# 13 Distributed generation

|  |
| --- |
| Key points |
| * Distributed generation produces power close to the point of consumption. This can avoid or defer network investment by helping to relieve network congestion, meet peak demand or improve system reliability. * However, the current policy environment sends opposing signals to distribution networks and customers about the economic value of distributed generation. * On the one hand, the capacity for local generation to substitute for network investment is constrained by regulatory obstacles, although some of these — such as a lack of information about network constraints and uncertainty about connection charges — have been, or are soon to be, substantially resolved. * On the other hand, government schemes (some now scaled back) to encourage renewable energy and reduce emissions have greatly increased the take-up of some forms of distributed generation, particularly rooftop photovoltaic (PV) units. * The take-up of rooftop PV units has produced minimal network savings as existing non‑time varying tariffs do not encourage householders to orient units to maximise generation in periods of peak demand. * The effective use of distributed generation to help reduce network investment needs to ensure that take-up is maximised in those parts of the system subject to the greatest constraints. Current subsidies do not assist that outcome (and some impose costs on network providers) and should be removed as soon as practicable. * Current pricing rigidities discourage efficient network use in peak periods. Eliminating these rigidities by introducing cost-reflective pricing would require major reform. Together with the introduction of carbon pricing, such reform would also make redundant an assortment of inefficient distributed generation subsidy arrangements, such as elevated PV feed-in tariffs and the Renewable Energy Target scheme. * Distributed generation can impose costs on the network — for example, where it requires investment to meet safety and reliability standards. * While significant in some areas, overall this appears a relatively minor concern, and recent regulatory changes mean that medium-scale distributed generators will now bear those costs. This provides improved signals for investment. * The immediate prospects for large network savings from the efficient use of distributed generation are low; some networks claim it has led to no deferral of network expenditure to date. It is anticipated that network savings should rise as regulatory obstacles to its uptake (including restrictions on cost-reflective pricing) are eliminated, and with technological change. * The use of benchmarking to achieve some theoretically efficient level of investment in distributed generation by network providers is impractical and would in any case be of limited assistance in promoting efficient network costs. |
|  |
|  |

In Australia, electricity supply is dominated by large generators that are remote from customers and, accordingly, must supply power to end users through a network of transmission and distribution lines. The vast network is a consequence of Australia’s geography; the economies of scale in generation; the advantages of generator proximity to large low cost energy sources; and the difficulties in finding suitable space for generators in major cities. Historically, the picture was starkly different. In Sydney for example, electricity was initially entirely generated within its environs, and even in 1958 internal supply still accounted for 75 per cent of its power needs (Wilkenfield and Spearitt 2004). It is a fraction of this today.

However, new technologies and policy decisions are slowly reversing the decline in local generation. Generation close to the customer (distributed generation or DG, also referred to as embedded generation) offers the scope for locally produced power to substitute for electricity delivered from the grid (demand replacement) and supply any surplus power into the grid. DG thus offers the potential to reduce network investment otherwise needed to service peak demand. DG can also, depending on circumstances, increase or reduce the need for network augmentation to ensure the reliability of electricity supply.

This chapter explores the role that DG might have in achieving efficient network costs. It outlines participants’ concerns about regulatory and non-regulatory obstacles to its use by network providers as an efficient non-network alternative to meet system constraints, and the state of regulatory reforms to address those concerns. Finally, the chapter considers whether there is a role in the regulatory framework for benchmarking specifically to achieve an efficient level of DG use by network providers (as part of a broader aim of achieving efficient network costs).

(Chapters 11–12 cover the implications for network investment from demand management options generally.)

## 13.1 What is distributed generation?

There are many definitions of DG (box 13.1) although most refer to generation located close to users and connected directly to the distribution network (rather than the high voltage transmission system). Chapter 10 of the National Electricity Rules defines a distributed (or embedded) generating unit as ‘a generating unit connected within a distribution network and not having direct access to the transmission network’.

|  |
| --- |
| Box 13.1 Definitions of distributed generation |
| Purchala et al. (2006) identify a range of definitions, including:   * The Institute of Electrical and Electronic Engineers defines DG as the generation of electricity by facilities that are sufficiently small to allow interconnection at nearly any point in a power system. * The International Energy Agency makes no distinction on generation capacity and defines DG as units producing power on a customer’s site or within local distribution utilities, and supplying power directly to the local distribution network.   The EU Electricity Directive considers DG to include all power plants connected to the distribution system (Scheepers et al. 2007, p. 10).  In the Australian context, the CSIRO notes:  Distributed generation refers to technologies generating electricity that are located in the distribution network. …. Generally, the technologies are connected at low voltage (<22 kV) and in a number of cases may provide additional energy in the form of hot or cool water for a variety of applications [i.e. co- or tri-generation]. (2009, p. 94) |
| *Sources*: CSIRO (2009); Purchala et al. (2006); Scheepers et al. (2007). |
|  |
|  |

DG covers a multitude of technologies: predominantly combustion engines using liquid or gaseous fuel, but also micro-turbines, solar power, wind power, biomass power and fuel cells (Ledwich et al. 2011, p. 9).

While most DG is comprised of units producing from a few kilowatts (kW) to units producing up to 10 MW, some DG units produce well in excess of this. However, as noted, the defining characteristic of DG is connection to a distribution network rather than the scale of generation (Ackermann et al. 2001, p. 201). Table 13.1 shows the Australian Energy Market Commission’s (AEMC) classification of DG units according to their installed capacity.

Table 13.1 AEMC classification of distributed generation units

|  |  |  |
| --- | --- | --- |
| Classification | Technical definition | Typical installation |
| Micro | Less than 2 kW and connected to low voltage network | Rooftop solar PV |
| Mini | Greater than 2 kW and up to 10 kW single phase or 30 kW three phase | Fuel cells; combined heat and power systems |
| Small | Greater than 10 kW single phase or 30 kW three phase, but no more than 1 MW | Biomass, small hydro |
| Medium | Greater than 1 MW but no more than 5 MW | Biomass, hydro, local wind generating units |
| Large | Greater than 5 MW | Co-generation, hydro, solar thermal |

*Source*: AEMC (2012e, pp. 162‑3).

Electricity production from DG is usually too small to be centrally controlled or dispatched by the Australian Energy Market Operator (AEMO). However, where the supply from DG is sufficiently large or predictable (such as from industrial scale co-generation plants), it is required to be despatched into the market under National Electricity Market rules (Dunstan et al. 2009, p. 22). The general threshold for such scheduled generation is a capacity of 30 MW or greater (AEMO 2010c, p. 18).

Although DG can include generators with a capacity in excess of 30 MW, these generators face a regulatory environment similar to that for large-scale decentralised generation. Accordingly, where the Commission discusses obstacles to networks’ efficient use of DG (section 13.5), this is primarily of relevance to DG with an output of 30 MW or less.

## 13.2 Scale of distributed generation in Australia

While there is no complete record of installed capacity of DG in Australia, the 2010 *Survey of Electricity Demand Management in Australia* provides a detailed snapshot of its network incidence. That survey sought data from the 20 Network Service Providers in Australia on DG in the residential, commercial and industrial sectors within their networks. Ten network providers responded with data on DG (table 13.2). For those respondents, DG constituted 798 MW of installed capacity — with 624 MW in the commercial/industrial sectors and 174 MW in the residential sector (almost entirely rooftop photovoltaics (PV)).

Table 13.2 DG reported by responding Network Service Providers**a**

Number of DG projects and capacity, April 2010

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Organisation | Residential | | Commercial | | Industrial | | Other | |
|  | No. | MW | No. | MW | No. | MW | No. | MW |
| ActewAGL | 3 051 | 5.9 | – | – | *–* | *–* | *–* | 6.73 |
| CountryEnergy | 16 500 | 43 | – | – | 2 | 60 | *–* | – |
| Energex | 40 224 | 77 | – | – | *–* | *–* | *–* | – |
| Energy Aust | 25 000 | 45 | – | – | *–* | *–* | 43 | 268.50 |
| Ergon Energy | – | – | 3 | 3.360 | – | – | – | – |
| Horizon Power | 1 | 1.46 | 1 | 0.500 | – | – | – | – |
| Integral Energy | – | – | 1 | 1.300 | – | – | – | – |
| SP AusNet | – | – | – | – | 1 | – | – | – |
| Western Power | 4 | 2 | 1 | 0.012 | – | – | – | – |
| TOTAL | 84 780 | 174.36 | 26 | 37.170 | 3 | 60 | 43 | 275.23 |

a This table reports 546 MW of installed capacity of the 798 MW reported in survey returns. The missing data were the result of organisations requesting no public disclosure of certain projects.

*Source*: Ghiotto et al. (2011, p. 18).

Since that 2010 survey, residential PV installations (stimulated by government subsidies and generous feed-in tariffs) have accelerated, with AEMO estimating total installed capacity in February 2012 of 1450 MW and noting that ‘Installed capacity is forecast to reach 5100 MW by 2020 and almost 12 000 MW by 2031’ (AEMO 2012b, p. iii).

In addition, technological change and the potential for lower costs provide scope for DG to increase its share of generation:

A rapid cost reduction in some distributed generation technologies — in particular Solar PV — has the potential to dramatically re-shape the Australian energy landscape. (Clean Energy Council 2012, p. 8)

## 13.3 Potential benefits of distributed generation

The CSIRO (2009, pp. 16‑28) and Dunstan et al. (2011b, p. 10) have identified a range of possible benefits associated with DG in Australia, including:

* reduced peak electricity demand
* reduced transmission and distribution network losses
* lower greenhouse gas emissions (from increased fuel efficiency resulting from the use of ‘waste’ heat in cogeneration or trigeneration or renewable energy)
* improved reliability of electricity supply, with greater energy security and improved system ancillary services.

Other possible advantages associated with DG include:

* the ease of finding sites for small generators to meet demand
* shorter installation times than for conventional generation plants
* the ability to use energy sources such as waste products or renewable resources which might otherwise have no economic use
* greater flexibility in choosing combinations of total cost and reliability that offer a better fit to the requirements of individual consumers
* electricity at a lower price than that delivered from the grid, particularly in rural and remote locations.

Given the scope of this inquiry, the Commission has focussed only on DG’s effects on network costs. However, in doing so, the Commission has also considered some of the potential perverse incentives that could lead to the inefficient use of DG as a network alternative.

## 13.4 Effects of distributed generation on network costs

As noted, DG offers the potential to avoid or defer network investment by helping to meet peak demand, reducing network energy losses and improving system reliability, security and power quality. However, DG can also impose costs on the network, as integrating two-way energy flows can cause technical and safety problems for infrastructure that was originally designed to only handle one way energy flows from large decentralised generators to customers.

### Network cost implications from peak demand effects

The most significant effect of DG on network costs arises from its potential to avoid or defer network investment that otherwise would be needed to cater for peak demand growth. This effect arises where DG power is consumed at the site of generation, replacing power that would otherwise be carried over the network. As the Clean Energy Council noted:

The benefits of … [DG] … have been proven in a number of trials across Australia. Focussed at the distribution network level they represent significant opportunity for efficiency gains through demand reduction. (sub. 31, p. 6)

This view echoes that of Dunstan & Langham (2010, p. ii) who, in regard to the network investment in New South Wales planned for 2009-10 to 2012-13, claimed:

… much of this new investment could potentially be deferred or avoided if peak demand growth was slowed through measures such as energy efficiency, peak load management and *decentralised or local energy generation*. (Emphasis added)

At the Commission’s public hearings following the release of the draft report, Sustainable Rural Australia provided an example of this, referring to the experience of Magnetic Island:

They had two submarine cables that connected them to the mainland and they were looking at the requirement to upgrade to a third cable, which was a several million-dollar infrastructure upgrade. With the implementation of energy efficiency programs, peak-demand management programs and the use of mainly solar photovoltaics on the island, they have offset or they have avoided the requirement to upgrade to a third cable ... (trans., p. 64)

The Dynamic Avoidable Network Cost Evaluation model[[1]](#footnote-1) illustrates the scope for network savings that DG might provide. Using this model, Langham et al. estimated the annual marginal value of deferring network investment in capacity needed to meet peak demand growth. Their estimates indicated there were many areas where the deferral value of investment otherwise needed to supply critical peak capacity was between $300–1000/kVA/year and where non-network alternatives, such as DG in its various forms, could provide the most efficient option to overcome network constraints (Langham et al. 2011, pp. 6‑7). Box 13.2 provides an example of how network businesses assess such network/non-network alternatives.

|  |
| --- |
| Box 13.2 Management options to meet peak demand: Charlestown case study |
| In 2009, Energy Australia (EA, now Ausgrid) investigated if there were cost-effective alternatives to a $40.5 million investment in infrastructure needed to ensure the Charlestown zone substation would have the capacity to meet expected peak demand in the summers of 2010-11 and 2011-12. EnergyAustralia concluded that if it could reduce demand by 4.9 MVA by summer 2012-13 it could defer this investment by one year and lead to savings of $2.64 million or $540/kVA.  It identified a range of non-network options, listed below.   |  |  |  |  | | --- | --- | --- | --- | | Non-network options | Peak load reduction | Total cost to EA ($Net Present Value) | Cost to EA ($/kVA) | | Tri-generation | 3.6 MVA | 100 000 | 28 | | Relocatable generator 1 | 3.6 MVA | 1 100 000 | 295 | | Relocatable generator 2 | 2.4 MVA | 870 000 | 361 | | Relocatable generator 3 | 0.3 MVA | 650 000 | 368 | | Lighting efficiency | 0.015 MVA | 70 000 | 470 |   Energy Australia’s analysis concluded:  The preferred option is a network support agreement with a tri-generation project. An alternative … is the use of temporary embedded generation … These options will be developed to enable implementation for summer 2010-11 and 2011-12. |
| *Source*: Ausgrid (2010b). |
|  |
|  |

Networks will tend to pursue DG to address capacity constraints if it is cost effective to do so. The (limited) evidence from the *Survey of Electricity Network Demand Management in Australia* reveals that, to date, other non-network options (particularly load management) have generally been more attractive than DG. That survey showed that the two reported DG projects with costs of $223/kW/year[[2]](#footnote-2) or less accounted for 10.8 MW of peak demand reduction whereas load management projects with costs of $223/kW/year or less accounted for 258 MW (Dunstan et al. 2011a, p. 18).

However, Dunstan et al. (2011c) also provide a measure of the extent to which DG (as part of a broader suite of demand management options) might in future substitute for grid-delivered electricity and, in the process, reduce the amount of network investment. Using the Description and Costs of Decentralised Energy model,[[3]](#footnote-3) they aggregate the annualised capital and fixed costs of expanding peak generation and network capacity to establish the actual cost of delivering electricity from the point of production to the point of consumption.

Their results indicate that, in the period to 2020, there is the *potential* for DG to provide over 4000 MW of peak power at a lower cost than expanding centralised supply capacity (Dunstan et al. 2011c, pp. 65‑8). This represents about 10 per cent of peak power requirements. Their results also highlight that commercial/industrial standby generation and co- and tri-generation are the most cost-effective DG options (with capital and fixed costs of expanding peak generation and network capacity of around $0.3 million/MW or less) while rooftop solar PV is the least cost-effective option (with typical costs just over $1.5 million/MW).[[4]](#footnote-4) This compares with gas or coal fired centralised generators, where the cost of expanding peak capacity is between $0.4 million/MW to less than $0.6 million/MW (Dunstan et al. 2011c, p. 68).

### Network cost implications from reliability and security effects

Regulatory requirements for reliability standards are also driving projected network investment and augmentation (chapter 15). In this arena, some DG has the potential to meet reliability requirements and so reduce the need for network augmentation. For example, in a report commissioned by the AEMC, Futura Consulting found:

Other potential benefits [from DG] … include enhanced reliability and security of supply. Notably, the dispersed nature of DG systems means that a reduction in output in any one generating system will not have a marked impact on overall reliability of supply. Reliability of supply is also improved because consumers are less subject to outages caused by transmission and distribution failures. This is particularly true for rural and regional consumers who can be subject to outages and voltage variations arising from their position at the end of a long distribution feeder. (2011, p. 36)

In discussions with a network provider, the Commission was told that a DG solution was more cost-effective for ensuring reliability of supply for a remote coastal town than network solutions of augmenting sub-transmission lines or duplicating the single line to that town. The network solutions would have cost in excess of $20 million (pers. comm., 25 June 2012).

Further, DG can offer improved energy security through network benefits such as voltage support and reduced reactive power losses, as well as improved system ancillary services, such as ‘black start capability’ and ‘spinning reserves’ (Dunstan et al. 2011b, p. 10; Pacific Economics Group, sub. DR48, p. 9).

While there are no comprehensive estimates of network savings attributable to improved reliability from DG, discussions with distributors indicate that such savings are small relative to those from reducing peak demand.

Finally, it is important to recognise that integrating DG into a distribution network also has the potential to *add* to network costs.

Modelling by the CSIRO for large DG penetration on four actual distribution feeders in Australia has previously indicated that while these problems exist, they were unlikely to be significant in the period to 2050 (CSIRO 2009, pp. 30‑1). That work suggested additional network investment to address these problems was likely to be relatively minor overall, although costs could be concentrated in some areas.

However, the massive (and largely unanticipated) growth in residential PV installations since 2009 is imposing added costs for some networks. For this type of DG, the AEMC has found that issues related to voltage rise and harmonic imbalances are a concern for the network where high concentrations of PV installations occur (Futura 2011, p. 11). Smart Grid Australia noted that the high level of solar PV on parts of the grid is causing issues of network stability and voltage control (trans., p. 252), while Ergon Energy noted:

Networks have not been designed to handle large export power flows at the distribution level … In Ergon Energy’s experience, high penetration levels of distributed generation have resulted in additional network augmentation costs. (sub. DR63, p. 8)

The Energy Networks Association has noted that these technical problems and associated network costs of DG integration should lessen as smart grids (box 13.3) evolve and are increasingly adopted (ENA 2010, pp. 1‑2; ENA 2011b, p. 7). This is particularly so for residential PV:

With electromechanical grids evolving to smart grids … as the grids become progressively smarter more aggregation will be possible, particularly with photovoltaics (PVs), [plug-in hybrid electric vehicles] and other distributed renewable energy sources.[[5]](#footnote-5) (ETSA Utilities 2010b, pp. 4‑5)

Further, the adoption of smart grid technologies (with their ability to provide real time scarcity pricing) would facilitate demand response and distributed generation when it is most needed (Hogan 2010, p. 7; Pacific Economics Group, sub. DR48, pp. 7‑8).

|  |
| --- |
| Box 13.3 What is a smart grid? |
| Building a smart grid involves transforming the traditional electricity network by adding a chain of new, smart technology. Examples of smart network components include:   * integrated communications infrastructure that enables near real-time, two-way exchanges of information and power * smarter measurement devices (including advanced metering infrastructure) that record and communicate more detailed information about energy usage * sensors and monitoring systems throughout the network that keep a check on the flow of energy in the system and the performance of the network’s assets * automatic controls that detect and ‘repair’ network problems * advanced switches and cables that improve network performance * IT systems with integrated applications and data analysis.   Smart technology can monitor, manage and maintain the network and enable two-way exchanges of energy and information, all in real time. |
| *Source*: ENA (2010). |
|  |
|  |

## 13.5 Obstacles to efficient network investment

Ideally, when network businesses consider how best to meet future demand, they should be neutral between network and non-network solutions to deliver the most efficient outcome. Unfortunately, this is not always the case.

Despite recent reforms aimed at facilitating the efficient network use of DG,[[6]](#footnote-6) participants highlighted areas that remain of concern and where further changes are needed.

### Participants’ concerns

Some participants contended that there is a general systemic bias towards network supply side solutions:

Current arrangements for investment at the distribution level do not drive innovation in the physical system. In particular, widespread rollout of demand side management, demand side participation, embedded generation technologies and supporting technologies seems unlikely whilst the regulatory framework incentivises network investment instead. (Clean Energy Council, sub. 31, p. 2)

However, networks have financial incentives to forgo DG investments whenever they reduce the network’s overall regulated asset base or reduce … energy sales. … Cost‑based, building block regulation creates inherent incentives for networks to forgo DG investments when these investments are more economical than network expansions’ (Pacific Economics Group, sub. DR48, pp. 10‑11)

Similarly, EnerNOC observed:

[Demand response] and distributed generation are effective substitutes for many types of network infrastructure. NSPs [network service providers] with efficient investment as their primary motivation would consider these on an equal footing with building new infrastructure, and choose the most efficient option. In the [National Electricity Market], this barely happens.

This suggests that there is a problem with the current regulatory framework: the overall balance of incentives seen by the NSPs do not result in them making the most efficient decisions. (EnerNOC, sub. 7, p. 2)

The AEMC noted concerns about the usefulness of existing rules regarding network planning to foster an efficient level of investment in non-network alternatives, such as DG and demand management:

Currently, Chapter 5 of the National Electricity Rules sets out a number of high level national requirements in respect of electricity distribution network planning. These requirements are general in nature and are supplemented by a range of state-based regulatory arrangements which differ significantly across jurisdictions.

As a result, there is a view that the lack of consistency and transparency associated with the current arrangements impedes efficient investment by distribution businesses and market participants. There is also a view that the current arrangements create a bias against the consideration of non-network alternatives in distribution network planning. (sub. 16, p. 4)

Similarly, SKM noted that although customers are becoming more active in self‑generation, they are not well informed about network costs and capability. This, it argued, leads to a situation where ‘integrated planning between customers and networks around embedded resources is inefficient’ (sub. DR61, p. 2).

Participants in concurrent reviews also had concerns about the adequacy of information on system constraints that is available to inform DG investment decisions, and about the obstacles presented by complex, costly and lengthy connection arrangements (VCEC 2012, pp. 44‑8; AEMC 2012e, p. 166). Participants to the recent Victorian Competition and Efficiency Commission (VCEC) inquiry into distributed generation also drew attention to barriers facing DG in the 100 kW to 5 MW range — after connecting to the network — in selling their surplus power into the retail market (VCEC 2012, p. 158).

EnerNOC noted that networks operating under weighted average price caps (as opposed to revenue caps) set by the regulator are still exposed to a disincentive to use DG as an alternative to network augmentation, despite efforts to counteract this effect (chapter 12 addresses this issue in depth):

When it comes to the use of demand-side alternatives, NSPs’ incentives are also muddied by the way the bulk of their revenue comes from per-kWh charges. This means that successful DR [demand response], embedded generation, or energy efficiency (EE) projects tend to decrease the NSP’s revenue and profits. …

Part B of the AER’s Demand Management Incentive Scheme is intended to reimburse NSPs to neutralise this effect. However, this is an awkward, inefficient approach, as each demand management project requires separate approval by the AER. As well as causing bureaucratic overhead, this leads to NSPs perceiving a risk that they will not be reimbursed. (sub. 7, p. 2)

The Energy Supply Association of Australia noted that many customers, including most residential customers, still do not face price signals that reflect the cost of the electricity they use (esaa, sub. 23, p. 9). Where this occurs, it distorts customers’ incentives to invest in DG as a substitute to consuming power from the grid (IPRA, sub. 36, pp. 6‑7). In turn, this restricts the choice of non-network alternatives that distribution businesses might choose from when deciding how best to meet system constraints. (Chapters 10 and 12 discusses this issue further.)

The City of Sydney (sub. DR58, p. 8) and Origin (sub. DR64, p. 5) argued that disproportionately high network tariffs applied to exports of DG power into local distribution networks, and that these constitute a major barrier to precinct scale DG:[[7]](#footnote-7)

The economies of scale of having a larger sized generator that has spare capacity to supply thermal energy to other buildings in the vicinity is largely hindered if other off‑site clients have to pay full network charges. (Origin, sub. DR64, p. 5)

The City of Sydney noted that overseas this problem has been resolved by treating the local public wires of the distribution network as if they were private wires, and paying the distribution network operator ‘use of service charges’. For these charges:

… there was a standardised calculation method, … which sets out what the charge should be for distance travelled, the amount of energy being exported et cetera … there’s a very detailed formula that you could literally take off the peg and apply that to Australia. (trans., p. 103).

This solution appears predicated on the principle that users of electricity should only incur a network charge in proportion to that part of the network used by the electrons they consume. However, identifying the source of any electrons used by consumers and identifying that part of the network used in getting those electrons from generation to final consumption, is impossible. Moreover, paying a theoretical marginal cost or ‘use of service charges’ for transporting DG-produced power to nearby users ignores the cost of providing a network that can deliver power should that DG-produced power fail. These considerations underpin the existing postage stamp basis for network charges.

Jemena noted that a network business is exposed to ‘s‑factor’ penalties if a DG provider that it relies on for network support fails to perform and, as a result, contributes to an event that causes the DNSP to incur a penalty. In Jemena’s experience, DG providers are generally unwilling to indemnify DNSPs against this exposure. This, it notes, has been a barrier to the development of network support arrangements with DG providers (sub. DR77, pp. 18‑9).

However, this situation appears to describe the freedom of DG providers to make commercial decisions on whether to enter into agreements to indemnify the DNSP, rather than any ‘barrier’ to DG providing network support.

Albeit outside the regulatory framework governing the National Electricity Market (NEM), submissions also pointed to the plethora of government schemes aimed at encouraging renewable energy and reducing greenhouse gas emissions. These schemes — which, for example, in some cases provide inefficiently high feed-in tariffs and generous allocations of Small-scale Renewable Energy Technology Certificates (the sale of which subsidises installation costs) — are stimulating excessive (and inefficient) investment in some types of DG (especially rooftop PV units):

The Businesses have experienced a greatly increased number of connection enquiries and applications in relation to distributed generation in recent years, as a result of State and Commonwealth Government climate change policies, programs and incentive schemes which seek to encourage greater investment in renewable and lower carbon intensive generation. (ETSA Utilities et al., sub. 6, p. 52)

The takeup of solar photovoltaic systems has been faster than expected due to the incentives provided by government. The perverse outcome is that these incentives have promoted the inefficient use of this technology from a network perspective, causing investment in networks rather than deferring it. (Ergon Energy, sub. 8, p. 25)

Moreover, as esaa noted (sub. 23, pp. 10, 78), rooftop PV units offer minimal savings from deferred network investment as system peak times do not usually coincide with peak sunlight and PV generation. Contemporary evidence supports this view:

A recent research paper published by Ausgrid indicated that the impact of rooftop solar on its summer peak demand has been small to date, despite the substantial take up in NSW. Using interval data from 26 744 installed solar systems over its peak demand period in early February 2011, Ausgrid noted that system peak time differed from the solar peak time, with the estimated output of the sample solar PV contributing only 32 per cent of the total installed capacity of PV during the peak period. Ausgrid indicated that there has been no network investment deferral as a result of installed PV on its network. (Deloitte 2012, p. 55)

### Recent and imminent reforms address many of these concerns, but some remain

Recent and impending reforms to the NEM’s regulatory framework appear to address many of the obstacles to the efficient network use of DG identified in submissions. However, some major obstacles remain, as do material differences between jurisdictions in the implementation of regulatory reforms.

#### General systemic bias towards network supply side solutions

Regulators have acknowledged concerns about systemic bias to network investment in the regulatory framework governing the NEM and have introduced reforms to address that bias.

Fundamental reform began in 2008 with the introduction of national rules governing the economic regulation of electricity distribution networks. Those rules aim to balance the incentives and obligations for distribution businesses to invest in non‑network alternatives (such as DG) with those for network infrastructure, and to encourage adoption of the most efficient option. The new rules require the Australian Energy Regulator (AER), when assessing distributors’ expenditure forecasts, to take into account the extent to which they consider, and provide for, efficient non-network alternatives. The AER has the discretion to reject proposals for capital expenditure on network infrastructure if it concludes that non-network alternatives would be more efficient (MCE 2012a).

#### Poor information on network performance and investment opportunities

The AEMC recently considered a rule change request that, among other things, would require distribution businesses to publish an annual planning report that provides information on network performance and planned system augmentation. This would include a requirement for distributors to identify and describe any forecast system limitations for sub-transmission assets and zone substations so that DG proponents are more easily able to identify investment opportunities (MCE 2012b).

The AEMC released a final determination on this rule change request in October 2012 (AEMC 2012c). The VCEC has observed that this rule change would lead to better long-term planning to accommodate DG and would also require distribution businesses to more actively engage with DG proponents (2012, p. 76).

Some inquiry participants noted that some states already impose such obligations on distribution businesses and some network businesses already adopt this approach. For example, SP AusNet publishes a *Distribution System Planning Report* which details expected augmentation requirements for a 10 year and five year horizon, respectively. It also outlines network support payments that could be available to providers of innovative network support options (pers. comm., 15 June 2012). Similarly, CitiPower and Powercor publish a *Transmission Connection Planning Report* and a *Distribution System Planning Report* on their websites, which describe feasible options to meet forecast demand and network constraints and invite interested parties to express interest in providing non-network alternatives (ETSA Utilities et al., sub. 6, p. 47).

#### Complex, costly and lengthy connection arrangements

Recent and proposed reforms have sought to simplify and expedite the arrangements for DG connection to the network, including:

* new connection charge guidelines under chapter 5A of the National Electricity Rules (AER 2012v)
* proposals for rule changes under the Small Generator Aggregator Framework which seeks to simplify the registration of small generator projects[[8]](#footnote-8) (AEMC 2012e, p. 164)
* proposals for amendments to the National Electricity Rules for connecting DG (to streamline the connection process) (MCE 2012c).

The VCEC’s final report for its inquiry into distributed generation observed that these reforms will address many of the barriers to the connection of DG (VCEC 2012, p. 93). The AEMC has expressed a similar view (AEMC 2012e, pp. 165, 168; AEMC 2012h, p. 39).

#### Barriers to on-selling surplus electricity from DG projects

The National Energy Customer Framework — introduced in the ACT and Tasmania on 1 July 2012 and South Australia on 1 February 2013 (and in New South Wales and Victoria as soon as practicable) — is intended to address regulatory constraints facing small to medium-scale DG in selling power surplus to their needs in the retail market (VCEC 2012, p. 159).

Under the framework, those selling electricity (including electricity from DG) are now subject to an authorisation regime, administered by the AER. Under this regime, sellers are required to either have a retailer authorisation or be exempt from the requirement. The AER has released an *Exempt selling guideline* (AER 2011c), which sets out its approach to retail exemptions and the types of exemptions it will allow.

In developing the guideline, the AER noted that distributed generators would need to apply for an individual retail exemption on a case-by-case basis. However, the AER:

… will grant exemptions in these situations where the initiative is in the long term interests of energy consumers having regard to all of the criteria and factors we are required to assess. (AER 2011c, p. 24)

While this reform aims to address retail licencing issues that might otherwise discourage DG, the Clean Energy Council (sub. 38, pp. 2‑5) argued that it leaves significant obstacles unresolved and creates new barriers to DG connections. It also noted that the reform is not yet universal across the NEM, as some jurisdictions have refused to implement the new arrangements (citing customer protection as their key concern).

#### Misalignment between networks’ profit drivers and the efficient use of distributed generation (as part of non-network alternatives more generally)

The AER has implemented a Demand Management Incentive Scheme[[9]](#footnote-9) to address systemic bias against non-network alternatives. In New South Wales, for example, the scheme consists of two parts. One part is a demand management innovation allowance (that provides a payment for demand management related activities), and the other is a provision for the recovery of foregone revenue where demand management initiatives reduce electricity consumption and where revenue is at least partially dependent on the quantity of electricity sold (for example, under a CPI-X price cap). It achieves this by raising the price cap above adjustments for the consumer price index and the X factor (AER 2012b, pp. 7, 17).

However, despite regulatory reforms and schemes aimed at neutralising systemic disincentives for networks to embrace DG, the current regulatory framework still fails to align the profit incentive of network businesses with a socially efficient level of investment in DG (AEMC 2012b, p. 1). In this regard, the problem of network price caps acting as a disincentive to using DG identified by EnerNOC (sub. 7, p. 2) is yet to be resolved.

Options to address these failings were the subject of the AEMC’s Power of Choice review, which released its final report in November 2012 (AEMC 2012u).

#### Lack of cost-reflective pricing

The lack of cost-reflective pricing referred to by esaa (sub. 23) and IPRA (sub. 36) is a fundamental obstacle to the efficient level of network adoption of DG. As Origin Energy noted:

The introduction of more cost reflective network pricing [would] make a material improvement to the business case for individual building and precinct cogenerated electricity. (sub. DR64, p. 5)

This issue though is particularly applicable to households and small businesses:

[For] large consumers, … tariffs tend to be bilaterally negotiated, but time of use tariffs are much more prevalent for these consumers. … For smaller businesses, some time of use tariffs are available, but tariffs are generally similar to those available to residential consumers. …

For large consumers who have a direct contract with the NSP, a capacity charge based on peak demand in a year is common … For most consumers, NSPs charge a flat price for each unit consumed. (AEMC 2012e, pp. 57‑60)

Residential consumers and small businesses are subject to some peak/non-peak tariffs (AEMC 2012e, pp. 60‑1). However, a more comprehensive use of cost-reflective pricing for these customers requires the support of governments to allow this and the widespread introduction of enabling technologies (such as smart meters). Loy Yang Marketing Management Company (sub. 25, p. 3) was sceptical of securing this support:

What is clear is that exposure to efficient prices is likely to be the most significant driver of change to end use electricity demand. However, this is unlikely to happen whilst retail price setting remains largely in the hands of [state] government.

As discussed in chapters 10–12, the Commission has recommended changes to facilitate the introduction of more cost-reflective pricing.

#### Government schemes promoting renewable energy and emission reductions

As noted, government schemes to encourage renewable energy and emission reductions have resulted in the rapid (and generally inefficient) growth of rooftop PV units. These schemes, though, aim to encourage aggregate electricity generation (to replace the greatest amount of electricity — and emissions — otherwise produced by fossil fuel-based generators) and have little regard for maximizing power output at times of peak demand or locating PV units in areas where network system constraints are most acute. The general absence of cost‑reflective pricing compounds this lack of incentives for the efficient location and use of rooftop PV units.

While these schemes continue, factors largely outside the control of distribution businesses will drive the level of investment in PV installations in any network.[[10]](#footnote-10)

The Commission has previously argued that rooftop PV units, supported by these schemes, have also been a relatively high cost option for reducing greenhouse gas emissions (PC 2011d, 2011e). The latter PC report estimated that the implicit abatement subsidies from these schemes for small‑scale PV were in the range of $177–497/t CO2 (PC 2011e, p. 15). However, as some participants noted, for *future* small-scale PV these costs would be significantly less as premium feed-in tariffs are progressively removed (TEC, sub. DR50, p. 6). The Commission’s latest estimates confirm this view. Taking into account current (January 2013) policy settings for feed-in tariffs and subsidies under the Renewable Energy Target scheme, the implicit abatement subsidies from these schemes for *new* small scale PV are likely to be in the range of $22–252 per tonne of CO2. The wide range arises because some jurisdictions have abolished or reduced their premium feed-in tariffs (that subsidy is now zero) whereas other jurisdictions still have relatively generous feed-in tariffs (South Australia, Tasmania, the ACT and the Northern Territory).

The Commonwealth Government’s introduction of a price on carbon should obviate the need for these schemes on abatement grounds. As the Independent Pricing and Regulatory Tribunal of New South Wales has noted:

In our view, the introduction of the carbon price and a move towards an emission trading scheme … removes the need for the RET [Renewable Energy Target] (and ultimately electricity customers) to continue to subsidise investment in the renewables sector. The RET is not complementary to the carbon price and does not cost effectively address any other significant market failure. (IPART 2012c, p. 1)

More importantly, even allowing for the falling cost of solar technology, rooftop PV units are an expensive way of delivering peak power (section 13.4) and these schemes penalise those in the community without solar PV systems with materially higher electricity costs. The latter occurs because energy retailers recover the cost of these schemes through higher power bills. In the case of the Renewable Energy Target scheme, for example:

IPART estimates that in 2012/13 the cost of complying with the RET [Renewable Energy Target] adds on average $102, or 4.8 per cent, to an indicative regulated electricity customer’s bill in NSW. This is significantly higher than was forecast when the RET scheme was amended in 2009 and 2010 … (IPART 2012c, p. 1)

Accordingly, the Commission considers that the current subsidies and the RET are inappropriate and governments should phase them out as soon as practicable. In practice, this would be likely to involve grandfathering existing subsidies and phasing in new arrangements to lessen industry disruption and consumer concerns.

Some states in the NEM have already acted to reduce feed-in tariffs that were grossly in excess of the tariff for power taken from the grid (VCEC 2012, p. XXV).

* South Australia’s price regulator made a determination in 2011 for net feed‑in tariffs applying to small-scale solar PV, which reduced the tariff by 27 cents per kWh (to around 23 cents per kWh).
* In New South Wales, in 2012, the Independent Pricing and Regulation Tribunal recommended removing the obligation for retailers to offer a gross feed‑in tariff of 20 cents per kWh for small-scale solar PV units and suggested that an appropriate net tariff would be in the range of 5.2–10.3 cents per kWh.
* In Queensland, in 2012, the new government announced it will reduce its net feed‑in tariff from 44 cents to eight cents per kWh from 9 July 2012.

And in Victoria, the government has committed to a new net feed‑in tariff to replace existing tariffs for rooftop solar PV, effective from 1 January 2013. This tariff will provide a minimum of eight cents per kWh, which reflects the adjusted wholesale price of electricity (O’Brien 2012b).

However, realising the potential of small-scale DG (and rooftop PV in particular) to reduce network costs and so benefit all electricity consumers requires more than this. Regardless of whether governments decide to remove these current subsidies, they need to change the basis on which small-scale DG is remunerated so that it reflects the actual value of providing power to the local grid.

From a conceptual point of view, this remuneration should encompass feed‑in tariffs that match the value of electricity produced and exported into the grid and payments that reflect the value to the network of relieving localised network constraints.

The VCEC examined this matter extensively in its inquiry into feed‑in tariffs and came to the same conclusion. Its report suggested that remuneration should be delivered by net feed‑in tariffs based on the wholesale value of electricity (adjusted for effects on system losses) and that the network value of DG be separately identified and paid for by distribution network service providers.[[11]](#footnote-11)

The VCEC also suggested that feed-in tariff schemes continue for existing customers of those schemes until those schemes expire, but be closed to new entrants within a specified time, and that a new feed-in tariff scheme (based on the wholesale value of electricity) be established to replace those discontinued schemes (VCEC 2012, p. XXI). The Commission endorses these suggestions.

Reimbursement on this basis would provide price signals that would better encourage the installation of rooftop PV units that maximized power output at times of peak demand and in areas where alleviating network constraints is most beneficial.

While remuneration along these lines could be expected to emerge should the cost reflective pricing envisaged in chapter 11 be introduced, in practice, introducing such pricing depends on the rollout of enabling technologies (chapters 10–11) and, thus, is not likely in the near term. Changing feed‑in tariffs to approximate the value of providing wholesale power to the grid at peak and non‑peak times is, however, not hostage to any such rollout and could be introduced for new rooftop PV units relatively quickly.

Introducing a separate payment by distribution businesses for the network value of DG is more problematic as this value will be time and location specific (esaa, sub. DR70, p. 5) — although the AER’s price reset process might be a vehicle to identify and permit such payments (VCEC 2012, pp. 85‑6).

In addition, EnergyAustralia observed that direct payment by distribution businesses to small-scale distributed generators is likely to be administratively inefficient and to undermine the relationship between the retailer and its customer. It suggested a preferable alternative might be for distribution businesses to publish tariffs and/or incentives for different DG types and areas, which retailers could then incorporate in product offerings to customers (sub. DR82, p. 6).

Similarly, while administrative complexity might rule out direct payments to small‑scale generators, this should not preclude an intermediary from making a business case for aggregating the contribution of small-scale distributed generators and seeking remuneration on their behalf.

Recommendation 13.1

Governments should, as soon as practicable, discontinue subsidies for rooftop photovoltaic units and other forms of distributed generation delivered via feed-in tariffs and the small-scale component of the Renewable Energy Target scheme.

State and territory governments should change the way small-scale distributed generators are reimbursed by:

* instituting arrangements for network businesses to remunerate such generators at a level that reflects the savings in network costs from distributed generation capacity and output, particularly taking into account the extent to which distributed generation reduces the requirements for peak network capacity
* setting feed-in tariffs that approximate the wholesale price of electricity at times of peak and non-peak demand.

To provide a transition to the new arrangements, current feed-in tariff schemes should continue for existing customers until the end of their contract period or until those schemes expire (whichever is earlier), but be closed to new entrants one year from the governments’ formal acceptance of this recommendation. Prior to that date, state and territory governments should develop replacement feed-in schemes with tariffs that approximate the wholesale price of electricity.

## 13.6 Benchmarking to achieve efficient levels of network use of distributed generation

EnerNOC argued that network businesses should make more use of demand-side measures (of which DG is part) to meet peak loads. It noted that the top end of the load duration curve is most efficiently addressed through these means (sub. 7, p. 4) and, following from this, called for benchmark standards to achieve some target level of investment in demand response options to meet peak demand:

We would advocate explicit benchmarking of [network service providers] on the proportion of the extreme peaks in demand they face that they address through [demand response options], instead of by building infrastructure. (EnerNOC, sub. 7, p. 4)

For benchmarking to be a practical regulatory tool for fostering an efficient level of network usage of DG it must satisfy four conditions:

* it would need to be feasible to identify an efficient level of network investment in DG
* benchmarking some level of investment in DG would need to be consistent with efficient network investment generally
* network businesses would need to have substantial control over the level of DG connected to their network
* ‘like with like’ comparisons would need to be possible.

In practice, none of these conditions is satisfied.

Identifying some theoretically efficient level of network investment in DG to serve as a benchmark for networks to achieve is not practical as the level and form of DG connected to networks is not within the control of distribution businesses. This is exemplified by the substantial and growing residential uptake of PV units and the City of Sydney’s plans to supply 70 per cent of that local government area’s electricity needs by 2030 (City of Sydney, sub. 39, p. 2).

Despite major actual and impending reforms to the regulatory environment, there are still significant regulatory obstacles inhibiting network businesses’ use of DG. Further, these obstacles are not uniform across all jurisdictions in the NEM. Until these obstacles are resolved and networks in all jurisdictions face consistent incentives to use DG, setting a standard level of efficient investment in DG is not realistic.

Factors outside the NEM’s regulatory arrangements also exert a material influence on investment in DG (notably, a general lack of cost-reflective pricing and schemes that subsidise rooftop PV units). These factors, too, vary markedly between jurisdictions and effectively preclude identifying some optimally efficient level of DG that networks should aim to implement. As the esaa noted:

… it is a tall order for a [distribution network service provider] to forecast the efficient level of expenditure … when they do not have control over the take-up of distributed generation. Changes in both federal and state and territory government policies for subsiding small-scale PV have in recent years driven a rapid boom in PV installation followed by a strong deceleration as the policies were scaled back or withdrawn at short notice. Planning for such policy changes is challenging. (sub. 23, p. 11)

Moreover, setting a benchmark standard for the level of network investment in DG introduces a bias for DG as a solution to system constraints rather than allowing options to be chosen on their merits. This approach is inconsistent with a regulatory regime aimed at fostering network behaviour to deliver efficient costs.

As noted, distribution businesses have limited control over the level and form of DG within their networks. In these circumstances, benchmarking would be of little value in identifying ‘efficient’ behaviour with regard to optimal network investment in DG.

Finally, because the obstacles and incentives to invest in DG materially differ in each jurisdiction, ‘like with like’ network comparisons are not possible. Under such conditions, benchmarking networks’ investment in DG would be ineffective as a regulatory tool for achieving efficient network costs.

#### Benchmarking as a diagnostic tool

While benchmarking levels of DG should not be used as a measure of network efficiency, it may be useful in identifying broad trends between networks. For example, if one network used significantly less DG than similar networks, it would be worth investigating why this was the case. This investigation may find evidence on whether DG is being inefficiently ignored, a finding that could then be incorporated in revenue determinations.

This type of comparison may become more important if, over time, new generation and smart grid technologies lead to an increased uptake in DG.

1. This model was developed under the auspices of the Intelligent Grid Cluster; a collaborative research venture between CSIRO and the university sector. The application of the DANCE model to network planning was supported by Sustainability Victoria and assisted through cooperation with Victorian network businesses CitiPower–Powercor, Jemena Electricity Networks, United Energy Distribution and SP Ausnet. [↑](#footnote-ref-1)
2. kW/year and kVA/year are commonly used interchangeably. In practice, 1 kVA is equal to about 0.95 kW. The formula for conversion is ‘Power factor’ \* kVA = kW, where the power factor is a measure of the efficiency of conversion of electricity into ‘work’. [↑](#footnote-ref-2)
3. This model was developed under the auspices of the Intelligent Grid Cluster by a collaborative venture between CSIRO and five leading Australian universities. It also incorporates feedback from industry participants. [↑](#footnote-ref-3)
4. The Melbourne Energy Institute (sub. DR73, p. 2) noted that advances in technology are improving the cost-effectiveness of solar to provide distributed peak generation capacity, referring to an example of where a 20 MW solar power facility in the ACT is expected to deliver power at around $0.8 million / MW peak. [↑](#footnote-ref-4)
5. Plug-in electric vehicles provide a storage option and, thus, the expected future increase in their use offers the potential to improve the viability of residential-based DG from rooftop PV panels. [↑](#footnote-ref-5)
6. For example, reforms to the National Framework for the Economic Regulation of Distribution and the National Framework for Distribution Planning and Expansion (MCE 2012a, 2012b). [↑](#footnote-ref-6)
7. It is worth noting that Clause 6.1.4 of the Rules aims to ensure distribution-connected generation is treated equally to transmission-connected generation by prohibiting the application of charges for energy exported to the distribution network. [↑](#footnote-ref-7)
8. ‘Small’ in this context refers to generators that are less than 5 MW or otherwise subject to AEMO’s standing exemption from registration as a generator (AEMO 2009a, p. II). [↑](#footnote-ref-8)
9. This scheme includes distributed generation as per the AEMC Rule Determination, *National Electricity Amendment (Inclusion of Embedded Generation Research into Demand Management Incentive Scheme) Rule 2011 No. 11*, December 2011. [↑](#footnote-ref-9)
10. The Small-scale Technology Certificates solar multiplier offered under the RET scheme was reduced from two to one on 1 January 2013 (Combet 2012). The Climate Change Authority conducted a review of the RET scheme in 2012 and released its final report in December 2012. That report recommended that the Small Scale Renewable Energy Scheme continue and its broad structure remain largely unchanged (Climate Change Authority 2012, p. vii). [↑](#footnote-ref-10)
11. In Victoria, the Essential Services Commission’s Electricity Guideline No 15 already provides for this to occur (Jemena, sub. DR77, p. 18). [↑](#footnote-ref-11)