August 2007

Revised Demand Side Response and Distributed Generation Case Studies

NERA
Economic Consulting

Marsh & McLennan Companies

Project Team

Greg Houston, Director NERA Economic Consulting

Robert McMillan, Consultant NERA Economic Consulting

Peer Review

Jeff Balchin, Director Allen Consulting Group

NERA Economic Consulting
Darling Park Tower 3
201 Sussex Street
Sydney NSW 2000
Tel: +61 2 8864 6500
Fax: +61 2 8864 6549
www.nera.com

Contents

List of Tables

List of Figures

List of Boxes

1. Introduction

This report has been prepared by NERA Economic Consulting (NERA) and peer-reviewed by Jeff Balchin of the Allen Consulting Group (ACG). It forms the second part of the principal report[1] (Part One) reviewing the effect of the proposed initial National Electricity Rules (the Rules) for the regulation of revenue and pricing of electricity distribution service providers on incentives to undertake demand side responses (DSR) and distributed generation (DG). This will assist the Network Policy Working Group (NPWG) of the Ministerial Council on Energy (MCE) in its development of the initial Rules.

This second part to the above report considers six case studies with a view to identifying any distortions in the valuation and utilisation of DSR and DG arising under the existing Rules and related instruments. These six case studies are:

1. the large scale roll out of photovoltaic (PV) infrastructure to residential customers;
2. the roll out of advanced metering infrastructure with active load control (or pricing signals) to reduce peaks and support energy efficiency programs;
3. the installation of DG by large users that require back-up connection;
4. the use of mid-size DG to supply peak power and network support;
5. the use of a large scale DSR project to relieve network constraints in a central business district; and
6. the adoption of demand management techniques by large industrial users to reduce demand for network capacity.

These case studies are addressed sequentially in each of the following sections of this report.

Before examining the various case studies in detail it is helpful to summarise the framework developed in our principal report in order to identify any distortionary effects arising from the proposed distribution rules. As a general proposition, potential distortions in the valuation and utilisation of DSR and DG are likely to arise if the costs incurred by one party in the electricity supply chain can not be translated into an equivalent or greater level of benefits accruing to that party or another party in the chain. The framework we have therefore adopted for examining each of the case studies involves assessing the costs and benefits of each case, identifying to whom these costs and benefits accrue, and then assessing the extent of any inappropriate incentives arising from the potential misalignment of costs and benefits.

Applying this framework we have identified a number of regulatory impediments that need to be addressed in developing the initial Rules. In broad terms, our assessment reveals that regulatory limitations to the efficient pricing of network services are a significant impediment to cost and benefit alignment. For example, in most of the cases examined, constraints to efficient tariff rebalancing and to tariff reassignment limit DNSPs' ability to align their prices and/or revenues with the costs they incur.

---

1 NERA, *Part One: Distribution Rules Review – Network Incentives for Demand Side Response and Distributed Generation*, April 2007

These case studies were revised in May 2007 to reflect the proposed changes to the national frameworks for network planning, network connection arrangements and connection charges. The implication of these proposed frameworks on the case studies is set out at the end of each chapter.

2. Large scale PV roll out

Large scale PV rollout is an often discussed possible form of DG, particularly given anticipated future cost reductions in PV generation infrastructure. The Commonwealth government's Solar Cities program is an example of interest in pursuing this possibility and over the next few years will provide useful insights into the value of PV – particularly if it is structured so that it seeks to combine PV roll out with the facilitation of effective price signals for demand side response through advanced metering infrastructure (AMI).

This case study considers the implications for DSR and DG (PV being a form of DG) of large scale PV roll out such as that proposed under the Solar Cities program. This analysis is assisted by examining the results from examples of smaller-scale PV roll out projects conducted to date. However, it is useful to distinguish between these programs and Solar Cities. In particular, the latter will attempt to combine various aspects of AMI, price signalling, DSR and energy efficiency measures to gain enhanced understanding of the potential benefits of PV when integrated into retailer pricing arrangements. These examples are considered separately below.

2.1. Historic PV roll out examples

Newington Village and Kogarah Town Square, both of which are located in NSW, provide examples to date of PV rollout projects that have already been undertaken. These two projects have been subject to post project evaluations, the results of which provide some insight into the ability of PV to alleviate network constraints.

In summary, these evaluations found that PV installation had little influence on peak demand arising from residential customers. This was principally due to the timing of peak residential demand not coinciding with that of PV output. Therefore the ongoing requirement for stand-by capacity to cover times when PV output is insufficient to cover a residential customer's consumption needs remained largely unchanged.

It is possible that these findings may be influenced by the relatively limited scale of PV infrastructure installed in these roll outs – although it is not clear that increasing the scale of PV installation will improve the off-setting of peak *residential* customer demand. This is because PV output tends to peak between 10:00am and 2:00pm (in line with the positioning of the sun) while peak residential demand tends to occur between 6:00pm and 10:00pm.

PV installation may give rise to more potential in terms of avoided distribution network costs where demand in the relevant location is driven by industrial and commercial load, because such load tends to correlate more closely with peak PV output. However, the results of these evaluations further suggest that even where peak PV output corresponds with peak commercial and industrial demand, there was sufficient variance in PV output that it did not consistently mitigate peak demand. The scale of PV output (at least associated with the capacity of PV infrastructure installed in these cases) was also insufficient to alleviate network constraints or facilitate network augmentation deferrals.

It should be noted that the conclusions drawn from these two examples relate only to distribution network benefits; other benefits (not considered here) may have been realised by customers and/or their retailers.

The details of these two projects can be found in Box 2.1: Newington Village and Box 2.2: Kogarah Town Square.

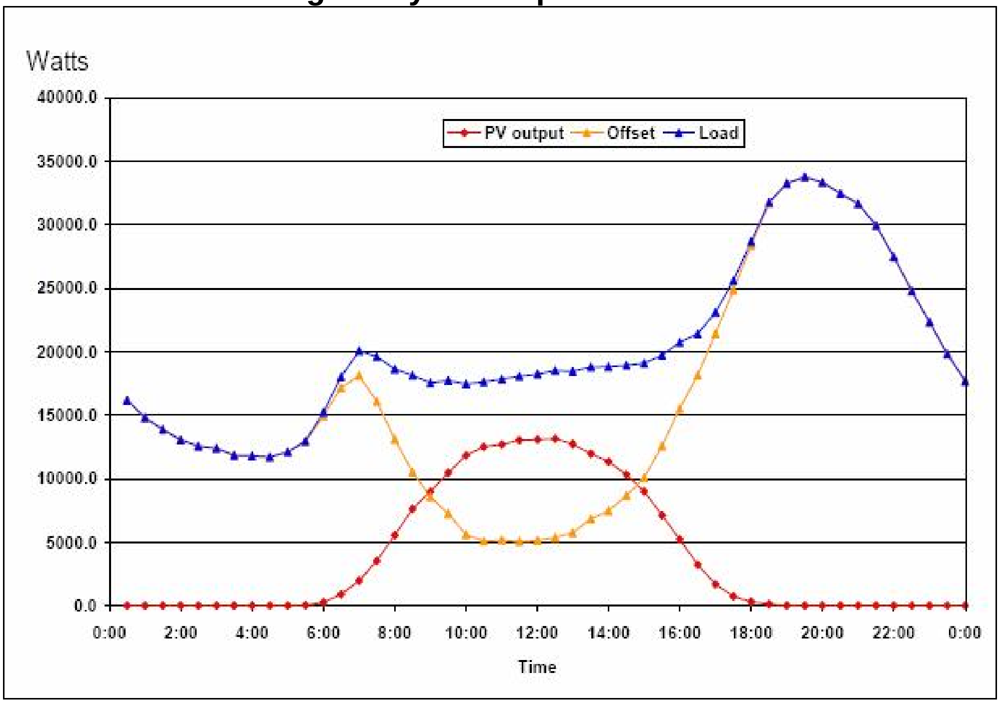
Box 2.1: Newington Village

Newington Village was established as an energy and water efficient development to accommodate athletes for the Sydney 2000 Olympics. All free-standing homes in Newington Village are equipped with PV systems and solar water heaters. By 2004, 780 homes had been built with 1000 Wp of PV each and 199 houses with 500 Wp each. Passive solar design features, energy efficient appliances and grey water systems are also used in all homes and were expected to reduce the houses' overall energy and water usage relative to established Sydney homes.[2]

The Centre for Energy and Environmental Markets at the University of NSW has assessed data from 30 Newington Village free-standing houses over the financial year 2004-05 as collected by the NSW Department of Planning. This assessment revealed that PV was ineffective in reducing the peak network capacity demand of residential households (see Figure 2.1) because:

- average daily PV output per household (3.16 kWh) accounted for 19.6% of daily consumption (16.12 kWh); and
- the timing of residential peak demand by household (between 6 pm and 10 pm) did not correspond to the PV peak output (10 am and 2 pm).

Figure 2.1
Average daily PV output and HH load

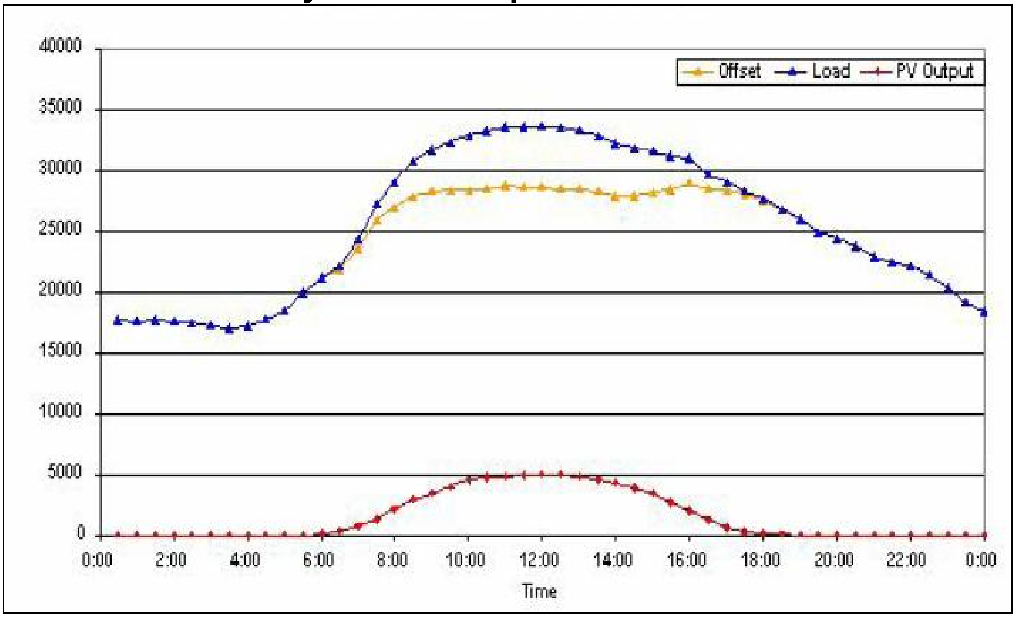


Source: Centre for Energy and Environmental Markets

[2] Centre for Energy and Environmental Markets, Newington Village: An analysis of photovoltaic output, residential load and PV's ability to reduce peak demand, February 2006, p.3.

While the assessment found that PVs did not reduce the peak network capacity demand of residential customers it did find that the PVs were effective in reducing the peak demand of the Homebush sub-station, which has a large industrial and commercial loads customer base. Specifically, the assessment found that the peak demand for the substation arose between 11 am and 2 pm which corresponded to the PV peak output period between 10 am and 2 pm. According to the results of this assessment 29.5% of PV output was contributing to reduction in the sub station peak demand as illustrated in Figure 2.2. We note that the PV output has been multiplied by a factor of 10 to make it visible on the chart[3]

Figure 2.2
Homebush Bay sub station peak demand and PV offset



Source: Centre for Energy and Environmental Markets

While the Newington investigation provided a favourable outcome at the sub-station level, it is worth noting that this outcome was extrapolated from residential PV output as a proxy for the actual output of the Homebush Stadium and other commercial PV installations.

It is also worth noting that the DNSP that owns the Homebush Bay sub-station, Energy Australia, has advised that despite the coincidence of peak PV output and peak sub station demand, the volume of PV energy exported at times of peak demand was so small as to be immaterial for their network planning purposes. In other words, the reduction was less than the error margin built into the demand forecasting for network planning purposes.

3 Ibid, pp. 3-7.

Box 2.2: Kogarah Town Square

Kogarah town square (KTS) is a mixed use development comprising 193 residential apartments, $2461m^2$ of retail space, $2176m^2$ of office space, $1405m^2$ of council space and 571 car spaces. The site was built with a 160kW PV power system (PVPS) at a cost of over $2 million. Energy Australia completed an investigation into the effectiveness of the KTS PVPS as a network peak reduction option.[4] It examined data collected over the period January to March 2004, ie, summer only, which corresponds with Sydney's summer peak.

The investigation identified that while the time of peak PV output and peak KTS site load correlated well (the load was primarily driven by commercial use), the PV output was only a fraction of its potential capacity and thus the demand reduction was much less than anticipated.[5] In fact, over the period, the reduction in peak demand represented only 9% of site peak demand and the PV output was highly volatile relative to customer load.[6] This reduction represented only 28% of the PV capacity that the KTS PVPS was, according to manufacturers, expected to produce.

A further conclusion of the investigation was that the 11 cents per kilowatt hour (11c/kWh) energy export tariff 'commonly offered' by incumbent NSW retailers is likely to overstate the actual (wholesale energy) value of exported energy. Using the spot prices that coincided with PV output the report found an appropriate price would have been 7c/kWh. The report noted that since it only examined energy and prices over the summer months, the actual annual value would be even less than this figure.[7]

Overall the review of the KTS project found significant variation in actual PV output during business peaks. In other words, the PV infrastructure could not be relied upon to consistently reduce the need for the provision of stand-by network capacity. This observation supported the conclusion that PV generation is of limited benefits as regards network alleviating network constraints.

2.2. Solar cities program

The Solar Cities program is an example of a proposed large scale roll out of PV infrastructure to residential and commercial users. Through this program, residents and companies located in Blacktown, Townsville and northern Adelaide will receive subsidies if they install PV infrastructure and invest in demand management and energy conservation measures. Principally, the program is designed to evaluate the benefits of combining PV with effective price signals (achieved through the concurrent roll out of AMI) and demand side measures. Specifically:

§ 3,000 solar photovoltaic panels will be installed on private and public housing and on commercial and iconic buildings;

---

4 Energy Australia, Kogara Town Square Photovoltaic Power System Demand Management Analysis, 1 September 2005.

5 Factors identified as contributing to this low level of output and demand reduction include the high failure rate of inverters, and the lack of effective monitoring and maintenance arrangements to ensure all inverters were working correctly. The PV cells were found to be relatively low maintenance.

6 Ibid, pp. 15-16.

7 Ibid, pp. 19-20.

- 2,400 solar hot water systems will be installed in private and public housing;
- 13,500 smart meters will give residential customers real-time information on energy use;
- 6,000 energy efficiency consultations will be conducted in households and businesses; and
- 70,000 energy efficiency packs will be available for households and commercial customers, to support their energy efficient choices.[8]

The nature of each of these solar cities projects varies in line with the benefits and beneficiaries anticipated. For example:

- the Townsville project is predominantly expected to deliver savings at the network level through the deferral of feeder upgrade to Magnetic Island; whereas
- the northern Adelaide project is driven by retail savings sought by the project partner Origin Energy.

2.3. Costs and benefits

PV generation has the potential to serve two key purposes:

1. to enable the PV owner to substitute own-sourced energy for network delivered energy; and
2. to export small amounts of energy into the network for use by other users.

Both these outcomes will reduce the amount of energy delivery capacity required at times when the PV is producing energy. However, in order to give rise to network capacity cost savings, these reductions must coincide with times of peak network capacity usage, and do so predictably. Where this is not the case, PV's network benefits may be limited and may simply result in lower levels of network utilisation for the majority of the time.

The principal benefit of PV energy export that is not coincident with peak demand arises from reduced distribution losses. However, under current National Electricity Market (NEM) arrangements the cost of losses is borne by retailers and generators, rather than treated as part of the cost of distribution network services. In that sense, the treatment of losses is outside the scope of this report.

Nevertheless, at section 8.2.2.3 of our principal report we question whether the current treatment of losses – and, in particular that distributors have no financial exposure to losses – is likely to deliver an environment in which losses are optimised. However, it is not clear that the introduction of such an arrangement would assist or complicate arrangements for DG – including PV – to seek a return on the benefits it creates. Our Part One report recommends that further analysis be undertaken on whether the current treatment of losses is consistent with promoting efficient distributed generation projects.

Whether or not network benefits are achieved from PV will therefore depend upon:

8 Australian Government media release Solar Cities – The Facts to Date, 13 November 2006

- the extent and predictability of alignment of peak PV energy output with peak network usage; and
- the scale of PV generation capacity installed and producing relative to the scale of customer demand in that location.

Even where PV output does coincide with peak demand, it will only provide network benefits where this coincidence is firm, ie, where there is certainty that the PV output will occur at all times of coincident peak demand. Where there is uncertainty in PV output (ie, due to cloud cover or inverter or connection failure) this reduces or may even eliminate the network benefits since the network owner will still be required to provide sufficient capacity at those times when PV output is interrupted.

A key question regarding PV firmness, even amid large scale PV generation capacity is the common mode of generation, ie, the sun. Where there is cloud cover, all PV generating capacity may be reduced simultaneously. This is referred to as 'common mode failure' and may be viewed as equivalent to the generation impacts of a widespread interruption to gas supply, ie, the output of all gas-fired generators being constrained at the same time.

There is also a potential for PV to impose costs on the network, or at least to require the specification of PV connection rules and policies. For example, DNSPs may need to implement system protection and safety policies to cover:

- issues arising from scheduled works that require lines not be live, which is complicated by the fact that the DNSP does not have control over the PV energy exported into the system;
- metering requirements that facilitate the metering of energy exported into the network, ie, such as some of the options under consideration for the AMI roll out and being trialled through the Solar Cities program; and
- where PV output reaches a scale sufficient to provide network support, additional measures may be required to maintain the 'firmness' of that support, including:
  - scheduling of PV unit maintenance and downtime to avoid coincidence with times of peak demand; and
  - communication protocols to advise DNSP of faults and outages that may cause a spike in the customer's demand on the network (equally relevant to large users and distributed generators).

For large scale PV generation where the purpose of PV is for energy export rather than substitution of a customer's demand, DNSPs may also need to invest in network reconfiguration, reinforcement, or additional voltage variation management. The magnitude of any such consequences inevitable depends upon the configuration of load and of networks serving that load. For example, the network cost consequences of large scale PV rollout in the commercial sector – which operates with a load curve duration that is distinct from that applying to residential customers – may be quite different from that in residential-focused areas of a distribution network.

In any case, such costs (ie, deep connection costs) would be assessed and paid for via the terms agreed in the PV generator's connection agreement (see section 8.3 of Part One). Such large scale PV may be viewed as DG and attract costs and benefits similar to those examined in chapter 5, although the extent to which PV power can be scheduled at peak times is likely to depend upon the correlation of those times with the availability of sunlight, and/or the availability of energy storage technologies.

In principle, PV may have the potential to defer transmission system upgrades, since it represents a form of generation that does not require use of the transmission system. Whether or not large scale PV is likely to defer transmission upgrades depends again on the extent to which output is produced at times of system peak, whether or not it is predictable or reliable, and whether the quantum of energy produced is significant.

We note that where a PV generator is of sufficient scale as to attract avoided TUOS payments, the DNSPs will effectively pay TUOS charges twice over the course of two or more consecutive years, since such costs cannot ultimately be 'avoided' by DNSPs (at least in the short term). This is because TNSPs are regulated via revenue caps and so all prices simply adjust upwards to compensate for any reduced TUOS revenues. This double incidence of cost will arise where DNSPs are permitted to recover avoided TUOS payments as part of their overall TUOS cost pass through. Where this is not the case, the DNSP will face an incentive to avoid connecting such generation to its network due to the misalignment of avoided TUOS costs and benefits. This issue is discussed in section 8.4 of Part One.

Table 2.1 Summary of benefits, costs and affected parties

Potential benefit ***Materiality***	**Benefit recipient**	**Potential costs** ***Materiality***	**Bearer of costs**
Reduced demand for network delivered energy *Materiality will depend upon the share of the PV customer's demand that is met by its PV energy generation.*	PV customer	Lost margin *The materiality will depend upon the extent to which a DNSP's charges are weighted towards usage charges relative to fixed or capacity charges.* *Consequences will be greater for price cap regulated DNSPs due to forgone revenue impact.* *Based on the Newington Village and KTS examples, impact will be immaterial.*	DNSP
Potential savings in energy purchase needs at peak spot price times *Based on the KTS study, less than 7c/kWh when considered over a full year.*	Retailer	Forgone margin, hedge book imbalance *Immaterial impact because a PV roll out would occur gradually and imbalance would likely be symmetric. Given that a retailer's hedge book is built up over time, retailers would be able to take account of PV installation. Further, a short-term hedge book imbalance could be either a cost or a benefit depending on the direction of imbalance and the spot price at the time.*	Retailer
Potential savings in reduced need for generation augmentation *Materiality depends upon relative growth in customer energy demand and installation of PV generation capacity. It is likely to be immaterial as customer load growth can be expected to exceed the rate of PV generation capacity installation.*	Generators	Forgone sales *Immaterial for current generators as customer load growth likely to exceed the rate of PV generation capacity installation.*	Generators
Potential coincident peak demand reduction *Immaterial under current metering arrangements since this only provides a benefit where the customer faces capacity charges. Most residential customers are on accumulation meters and face no metered capacity charge.* *Materiality would change under capacity pricing facilitated by AMI roll out.*	PV customer	Reduced capacity charge revenues *Immaterial under current metering arrangements as this only provides a benefit where the customer faces capacity charges. Most residential customers are on accumulation meters and face no metered capacity charge.* *Materiality would change under capacity pricing facilitated by AMI roll out.*	DNSP

Potential benefit ***Materiality***	**Benefit recipient**	**Potential costs** ***Materiality***	**Bearer of costs**
Potential coincident peak demand reduction (only where this can be relied upon for all peak times) *Based on the Newington Village and KTS examples, impact will be immaterial.*	DNSP	Potential service reliability penalties where DNSP relies on PV to reduce peak demand, and the 'firmness' of peak demand reduction provides insufficient level of reduction thereby contributing to service level deterioration	DNSP
Export energy into the network *Materiality directly determined by whether the customer receives a payment for exported energy (eg, Energy Australia 11¢/kWh, Origin Energy same as usage rate)*	PV customer	Payment to customer for exported energy (to the extent that these are offered to the customer and are not offset by reductions in wholesale energy purchase costs or government subsidies) *Materiality will depend upon the difference between the retailer's avoided costs and the price paid to the customer for exported energy.*	Retailer / DNSP
Avoided TUOS payments *Materiality directly determined by whether the customer receives an avoided TUOS payment from its DNSP, and whether this is passed on by the retailer (some jurisdictions pay avoided TUOS charges to small scale PV customers for energy exported into the network, eg, Energy Australia pays 0.3¢/kWh for avoided TUOS)*	PV customer	Payment of avoided TUOS charges to PV customer and non-avoidance of TUOS charges via the application of the TNSPs' revenue control overs and unders correction mechanism thereby increasing prices in the ensuring year(s). Further, the revenue control correction is not likely to see these price changes smeared across multiple TNSP customers, but rather the same DNSP because TNSPs charge their customers on a locational basis. Thus the same DNSP that had to pay the avoided TUOS charges will also have to pay the higher TUOS charges in subsequent years (ie, double incidence of costs). *Materiality is high where the DNSP is unable to recover these costs via transmission cost pass through, but low where it can.*	DNSP
Potential savings in reduced need for generation augmentation *It is likely to be of modest impact.*	Generators	Capital costs of PV i) PV cells ii) Inverters iii) Metering infrastructure (varies by jurisdiction as to whether this costs is borne by the individual customer or the DNSP) iv) Installation of storage devices to smooth PV energy	PV customer PV customer or DNSP PV customer

Potential benefit ***Materiality***	**Benefit recipient**	**Potential costs** ***Materiality***	**Bearer of costs**
		production and use	
		Ongoing maintenance – inverters have a short life (approximately 5 years), PV cells may require cleaning (though evidence suggests the energy production difference that cleaning makes is not warranted given the value of the additional energy produced)	PV customer
Provision of back-up supply guarantee *Material where the customer is charged on a capacity basis, immaterial where this is not the case.*	PV customer	Stand-by capacity i) Network capacity charge (distribution and transmission) *Immaterial where the customer is charged on a capacity basis, material where this is not the case.* ii) Generation (when back-up capacity is used) *Immaterial since costs captured in the wholesale energy price.*	PV customer Generator/Retailer
Revenue from capacity provision (to the extent that DNSPs are able to efficiently bill residential customers for capacity ie, via fixed charges) *Material where the customer is charged on a capacity basis, immaterial where this is not the case.*	DNSP	Provision of stand-by capacity (to the extent that these costs are not passed on directly to the customers via capacity charges) *Material where the customer is charged on a capacity basis, immaterial where this is not the case.*	DNSP
		Compliance with system protection and safety protocols or additional connection asset costs	PV customer
		System protection, reconfiguration and reinforcement (to the extent that these costs are not passed on directly to the customers via connection charges)	DNSP
Revenue from special metering and monitoring *Materiality depends upon ability to efficiently price these services.*	DNSP	Special meter monitoring costs, eg, if DNSP is engaged to monitor that PV cells are actually producing and that there are no apparent faults in the PV infrastructure	PV customer
		Special metering and billing (to the extent that these costs are not passed on directly to the customers) *Materiality depends upon ability to price these services efficiently.*	DNSP

2.4. Implications for rule development

The most effective mechanism to align the costs and benefits caused by PV installation with the costs and benefits received by the proponent is for DNSPs to structure their prices to end use customers efficiently. As discussed in Chapter 3 of Part One, efficient network charges could be expected to have significant emphasis on the extent of network capacity required by an end-user.

While the current evidence may lead one to question the extent to which PV may provide a benefit to network owners, the potential remains open. If DNSPs were to give greater emphasis to capacity-based charges, then PV proponents will be rewarded for the extent to which PV achieves a reduction in the use of network capacity (ie, usage at the network peaks), but the risk will reside with the PV proponent as to whether such a reduction in network capacity is actually achieved.

In addition, DNSPs will theoretically be indifferent to this form of infrastructure, where they are able to charge users on the basis of maximum capacity, thereby reflecting the costs of providing stand-by (or back-up) capacity to customers. Where the firmness and scale of PV generation are enhanced in the future, such that PV output aligns with times of peak demand and is able materially to reduce that demand, DNSPs can be expected to shift from indifference to preference for PV generation.

2.4.1. Regulatory or rule impediments

The initial Rules, as currently specified, contain a number of provisions that constrain DNSPs from establishing efficient prices. Aspects of the current rules that can impede the efficient valuation and utilisation of PV infrastructure include the following.

§ Tariff side constraints, which are included in many jurisdictional arrangements (at various levels of restrictiveness) and in the initial distribution pricing rules (at a rate of CPI+2%) for individual tariff components, are likely to prevent DNSPs from introducing efficient PV tariffs in a timely manner. Moreover, the side constraint of CPI+2% proposed for the initial rules is more restrictive than is currently applied in any jurisdiction (see Appendix A). The broader DSR and DG implications of such constraints are considered in section 7.8.1 of Part 1.

§ The tariff reassignment regulations currently applied by various jurisdictions may prevent the DNSP from reassigning customers to a PV tariff without prior customer consent. It may be difficult to get this consent where the PV tariff includes a higher weighting towards capacity rather than usage charging, even though this is likely to be efficient. Moreover, requiring consent adds to the administrative costs incurred in implementing the PV tariff. Such constraints are considered in section 7.8.2 of Part 1.

Additional regulatory impediments to the efficient uptake of PV that are beyond the scope of this review of the revenue and pricing provisions of the Rules may arise from:

§ Regulations on PV installation, operation and metering that vary across jurisdictions and as a consequence increase the costs incurred by PV proponents in encouraging its installation in different jurisdictions.[9] We understand that such impediments are currently being considered by the Utility Regulators' Forum in the context of its efforts to develop a code of practice for the connection of embedded generation.[10]

- Ambiguity in the market dispatch and settlement process with regard to the recognition of small scale PV exported energy, ie, it is unclear whether this energy provides any financial benefit to retailers as a form of unscheduled generation. While PV customers will continue to save money via substituting their own-sourced PV energy for grid delivered energy, the customer benefits may be increased where there is clarity in the attribution of any retail pool energy benefits and retailers are thereby motivated to place a value on such energy exports.

2.4.2. Incentive implications

The incentives for installation of PV arising from current and prospective forms of charging for network tariffs are dependent upon the metering technology that is in place or installed at the time of any PV capability. As discussed above, installation of PV will have three distinguishable effects on a customer's demand for network services, ie:

- a potential reduction in demand for network capacity at peak times;
- a reduction in energy drawn or imported to that customer's location, reflecting the role of PV in substituting for externally sourced generation; and
- the potential for energy to be generated by or exported from that customer's location, when PV output exceeds that customer's own demand.

Under the traditional form of accumulation metering present in many households, the first effect is immeasurable and so a customer is not in a position to benefit financially from any reduction in its demand for network capacity at peak times. However, the relevant reduction in energy usage at that customer's location will cause a reduction in the usage component of DNSP revenues and that customer's corresponding network charges. Given the generally high weighting given to usage charges for customers on accumulation meters, this effect is likely to weigh in favour of the PV customer.

Exported energy in the presence of an accumulation meter represents an extension of this effect, since the meter 'runs backwards' to the extent of the energy produced. In principle, a PV customer operating on an accumulation meter could receive a negative energy charge (ie, cash payment, rather than a reduced bill), although currently it remains unclear as to whether or not any DNSP's allow this to happen. In any case, the results of the PV trials discussed above suggest it is very doubtful that many such instances in fact arise.

---

9 Impediments to the Uptake of Renewable and Distributed Energy, Discussion Paper, MCE SCO, (http://www.mce.gov.au/index.cfm?event=object.showIndexPage&objectID=FF32A8E0-BCD6-81AC-19B5E8C841CE1EBE)

10 See http://www.mce.gov.au/index.cfm?event=object.showIndexPage&objectID=F701D099-65BF-4956-B9EC6FF27E9A17DC

In any case, the broad financial effect of PV installation ***that is not accompanied by simultaneous installation of AMI*** is likely to be negative for DNSPs, and so will discourage them from facilitating the connection or roll-out of PV.

Looking ahead, the Solar Cities program does contemplate the installation of AMI in conjunction with large scale PV, and so the above effects are likely to be modified by the probable enhancements to network tariff structures that will occur at the same time. In particular, it could be expected that DNSPs will or should be encouraged to adopt tariff structures that have a much greater peak capacity orientation, and give commensurately less weight to energy usage charges.

This development is likely to mean that customers installing PV will enjoy reductions in the capacity element of network charges, providing of course that PV is reliably able to reduce that customer's maximum demand. This is likely to improve the alignment of the costs and benefits of PV – as it relates to the provision and use of network capacity – between DNSPs and customers.

For the usage component of tariffs applying under AMI, the prospect of large scale PV is likely to encourage DNSPs to structure their network tariffs so as to reduce their dependence on such charges, since they are likely to overstate the magnitude of costs avoided (as compared with capacity orientated charges). The incentive to alter tariff structures in this way is consistent with a more efficient structure of network tariffs, and also with the alignment of the costs and benefits of PV-generated energy, as they fall between customers and DNSPs.

It should be noted that the network tariff incentives described above will not by themselves be guaranteed to influence the PV installation pay-offs faced by customers and efficient installation decisions. Rather, this will be determined by the extent to which retailers:

§ set final tariff structures that reflect the structure of their underlying network and energy components; and

§ offer energy payments or credits in the form of energy not taken (in the retail bill component) for energy exported into the grid.

At present only a few retailers offer retail tariffs to residential customers that include payment for energy exported into the grid, eg, Origin Energy and Energy Australia. However, subject to the constraints imposed by retail price caps, the presence of retail competition in most jurisdictions can be expected to result in retailers being encouraged to pass on any negative network usage charges provided to PV customers.

It should be noted that retail price caps are not applied to contestable market offers, and may therefore be irrelevant to the consideration of retailer PV-related tariffs. This presumption follows from the probability that customers who take such active energy related steps as to install their own PV infrastructure are also likely to consider contestable retail market offers (providing that retail price caps are not set so as to be artificially low).

Generally, connection of generation infrastructure to the distribution network is a non-standard service requiring specific negotiated terms and conditions. However, the connection of small scale photovoltaic (PV) generation to distribution networks by residential customers is likely to be at a scale threshold below which the costs of negotiating specific arrangements will outweigh the benefits of tailored connection terms and conditions. Given the above factors, it may be desirable for the Rules to specify that tariffs that allow for the use of small scale PV be regulated by means of direct control. This would need to be accompanied by a requirement that both the usage and capacity elements of such tariffs to PV customers are the same as those set for equivalent sized load, ie, to avoid price-based discrimination of PV.

Box 2.3
Rule recommendations

- The Rules should require that, once the appropriate form of regulation is determined for domestic distribution use of system charges, DNSPs should be required to allow such customers to install and use PV on the basis of the same usage and capacity tariff elements applying to equivalent sized load;
- Where tariff reassignment restrictions are to be included in the Rules, these should be limited to principles that ensure tariff assignment and reassignment are based upon:
  – customers' usage and connection characteristics, ie, the drivers of network costs; and
  – providing equal treatment to customers with similar usage and connection characteristics.

Box 2.4
Recommendations for consideration beyond the revenue and pricing Rules

- DNSPs should be encouraged or required to ensure that customers subject to large scale PV roll-out receive priority in the roll-out of AMI, thereby facilitating the development of network tariff structures that provide efficient signals for the installation of PV.
- Further analysis should be undertaken on whether or not the current treatment of losses is consistent with promoting efficient distributed generation projects.

2.4.3. Implications arising from the proposed national frameworks for electricity distribution network planning, network connection arrangements and connection charges

2.4.3.1. Implications arising from the proposed national framework for network planning

Under the proposed national framework for network planning, a mechanism will exist whereby a large scale roll out of PV cells can be considered alongside both network and other non-network solutions to alleviate an emerging capacity constraint.

Information on emerging constraints will be made available through two channels:

- the annual planning report; and

- the detailed request for proposals (RFP) issued by a DNSP when the network solution would require an estimated capitalised expenditure of $2m or more.

These planning documents should lower barriers to entry for proponents of a PV rollout by overcoming information asymmetries and making available:

- sufficient information early enough in the planning process to identify where such a scheme could potentially alleviate a constraint and lead to the deferral of a network upgrade;
- the distribution loss factor (current and forecast) that applies in the area of the constraint and which is therefore likely to apply to the PV scheme (see 2.4.3.4 for the implications of the loss factor); and
- information on the value of a deferral (in terms of $ per kVa per annum) and therefore the funds available for non-network solutions.

Furthermore, a DNSP will face a requirement to evaluate all proposals it receives on an equal footing, using clear and transparent criteria, and to publish the results of its analysis. Where PV represents an efficient option this process should provide a mechanism for it to receive equal treatment with other options. A mechanism will also exist for this analysis to be reviewed by an independent third party.

This evaluation would involve a cost benefit analysis that considers the wider network benefits such as reduced losses that a PV roll out could bring. However, to justify the deferral of a proposed augmentation any large-scale PV roll out would still need to satisfy the DNSP – to a reasonable standard – that the PV would reduce the peak loading on the assets where the constraint exists, and/or – if accompanied with a DSR program – that any reduction in demand would be available when required and coincide with the peak capacity load driving the constraint. Implications arising from the proposed national framework for network connection arrangements.

Under the proposed national framework for network connection arrangements PV cells will be defined as micro DGs and as such the owners of these cells will be able to connect to the distribution network using either the standard connection application process or the negotiated connection application process.

Where the standard connection application process is used the owners of PV cells will benefit from both:

- the reduction in the cost of connection as negotiation costs are avoided; and
- the stringent time lines that the DNSP must adhere to when processing the connection application.

The proposed framework will therefore have positive implications for the PV roll out case study.

If the negotiated connection application process is followed then the owners of PV cells will, like all other users, benefit from the inclusion of the technical requirements in the Rules, the streamlining of the connection process and the greater clarity provided by the single negotiation framework for standards, prudential requirements and where relevant connection charges.

2.4.3.2. Implications arising from the proposed national framework for connection charges

A large scale PV roll out may require some form of modification to shared network assets, arising from the need to provide export capabilities for suburbs that are producing energy and exporting to the network. In these circumstances, the proposed connection charging framework ensures that the PV owners only pay the dedicated costs associated with the provision of connection to the shared network. Implicit in this approach however is that a DNSP can require a PV energy provider within the connection agreement to constrain energy exports to the extent it impacts on the provision of network capabilities.

2.4.3.3. Implications arising from the proposed national framework for distribution loss factors

It is proposed that the distribution loss factors for distributed generators be a marginal loss factor, that is, reflecting the difference in the losses incurred with the generator operating compared to the situation without the generator. It is proposed that distribution loss factors for customers continue to reflect the average losses incurred in supplying energy to a particular area. The distribution loss factors that apply to distributed generation and customers will be static loss factors as at present (i.e. calculated in advance and applying for a year). As marginal losses tend to be greater than average losses, reflecting the non-linear relationship between losses and energy transported (losses on power lines increase with the square of the current), the DG distribution loss factor should be higher than the customer distribution loss factor.

As PV sites act both as a customer and an energy exporting distributed generator, the PV proponent will have the option of having two metered connection points so that the site is treated as a gross generator and gross consumer. The gross generation flows from the site will receive the ‘marginal’ distribution loss factor that applies to distributed generation and the gross consumption flows will receive the ‘average’ distribution loss factor that applies to customer distribution connections.

Distributed generators over a certain size, or those who request and pay the DNSP to calculate one, will receive a site-specific loss factor. For smaller sites – and hence more likely the case for a PV installation – the distribution loss factor should reflect a marginal loss factor averaged across the relevant geographic area, but estimated in a manner that keeps the computation burden to a reasonable level. For example, a ‘rule of thumb’ relationship between average and marginal loss factors could be used.

The distribution loss factor captures the benefit of avoided losses through its roles in the NEM’s dispatch (for scheduled generation) and settlement processes, of which settlement will be relevant to the PV installation. Energy exports from the PV installation would be treated as negative load for its associated retailer (and hence provide a benefit to the retailer) when it is settled, with the extent of load that is offset (and benefit to the retailer) reflecting the avoided losses calculated at the higher generation (marginal) loss factor. In contrast, the gross consumption will add to the retailer's load (and cost) – but with the losses reflecting only the average losses incurred in supplying energy to the area. More specifically energy exports by the PV will reduce the retailer's payments to the wholesale pool by an amount equal to:

- the value of the generation, being the product of the gross amount of energy generated at the PV site, the DG distribution loss factor, the regional reference price and the intra regional loss factor; minus

- the cost to the retailer of the customer's consumption, being the product of the gross amount of energy consumed at the site, the customer distribution loss factor, the regional reference price and the intra regional loss factor.

It can be seen from the equation above that even if the customer's consumption and generation at the site were identical, there would still be value created for the retailer so long as the DG distribution loss factor exceeds the customer distribution loss factor. With retail competition, it would be expected that the retailer would pass on the value created as a result of the PV exports to the owner of the PV installation.

The effects of the above changes will be to more properly value the avoided losses that a large scale PV roll out may achieve. Provided that the DG avoids losses on the distribution system, the use of a marginal loss factor should advantage DG compared to the previous position (except for the few DNSPs that already use a marginal loss factor for DG). The inclusion of distribution loss factors in the DNSPs' annual planning reports should ensure that the decisions of where to site a large scale PV roll out can respond to this important locational signal.

3. AMI roll out

Advanced metering infrastructure or AMI refers to an advanced meter that identifies electricity consumption in more detail than a conventional basic (accumulation) meter. AMI is capable of remotely reading consumption at intervals that reflect the frequency of NEM sales intervals. Certain forms of AMI will also enable load control capabilities for both retailers (for commercial management) and DNSPs (for safety and reliability management). This case study considers the roll out of AMI with active load control (and/or pricing signals) to reduce peaks and support energy efficiency programs.

Active load control may be considered as a substitute (or complement) to price signalling. For example, some large users who pay the spot price for their energy consumption and time of use pricing for network usage and capacity (such as smelters) may find it more efficient to have an interruptible tariff where the retailer or DNSP controls their load, rather than spending time monitoring these prices and managing their load themselves. This may arise because the billing period for customers does not provide price signals in a timely fashion thereby preventing the customer from voluntarily responding to the price signals. Hence the compromise arises by the customer allowing the DNSP or retailer to perform this role of managing usage response.

In this way, the economic benefits of active load control align with those arising from efficient pricing. Active load control may be viewed as a means of overcoming impediments to real time pricing, or as a form of price/service differentiation whereby customers are able to select a pricing option that is commensurately lower as to account for forgoing the right to manage their own load at certain times, ie, forgoing guaranteed supply.

Examples of AMI include the mandated advanced interval meter roll out in Victoria, Energy Australia's interval metering trial program and the AMI being installed in the three solar cities projects. All Australian jurisdictions have undertaken to participate in a national cost-benefit study regarding the roll out of AMI that reflects different circumstances in each jurisdiction, and to develop common specifications for any roll out. As yet no Australian jurisdiction has completed a study of the efficacy of AMI in achieving an actual reduction in demand by Australian customers.

Some network owners have commenced trials of AMI, though these have tended to trial the technical specifications and functionality of different forms of AMI rather than seeking to package these with pricing strategies, eg, Energy Australia's AMI trial.

3.1. Costs and benefits

The benefits arising from AMI relate primarily to the following key areas:

1. facilitation of time of use pricing (ie, more efficient and dynamic signalling of cost impost) assuming there are no constraints on DNSPs' or retailers' ability to change the structure of their prices, with consequent efficiency gains in the allocation of investment (both from users and electricity supply chain participants);
2. facilitation of network capacity-usage based charging;

3. enhanced information for network planning, NEMMCO generation scheduling (by means of more accurately specified constraint loss factor calculations and constraint algorithms), and retail energy purchase and hedging decisions; and
4. faster and cheaper network operations, eg:

– remote customer connection/disconnection;

– faster outage detection and management; and

– more efficient customer service and billing associated with customers switching retailers;

5. ability for individual customer DSR benefits to be metered and therefore captured by the customer/retailer rather than shared by all retailers.

The benefits arising from direct load control relate primarily to:

1. load control by retailers for commercial management purposes, ie, to enable greater differentiation of price offerings via interruptible supply tariffs and ability for retailers to reduce their exposure to energy spot prices; and
2. load control by DNSPs for:

– for safety and reliability management;

– greater differentiation of price offerings via interruptible supply tariffs;

– enhanced 'firmness' of customer DSR via ability to effectively control DSR at peak times; and

– the potential to aggregate individual customer load control DSR to facilitate a deferral of a network augmentation.

Table 3.1 Summary of benefits, costs and affected parties

Potential benefit ***Materiality***	**Benefit recipient**	**Potential costs** ***Materiality***	**Bearer of costs**
Greater visibility of time of use price signals to enable real time demand management, decisions by customers (or by retailers and DNSPs under load control tariffs) *Material impact where a customer's load is materially either more (negative impact) or less (positive impact) heavily weighted during peak consumption periods. Negative impact will be mitigated to the extent the customer can shift their load or reduce their coincident maximum demand.*	Customer	Additional metering charges (where these are higher than existing charges due to the relatively more expensive metering infrastructure) *Materiality will depend upon the manner in which AMI roll out charges are passed through to customers and the cost of the particular AMI specifications required in the roll out.*	Customer
Potential bill savings via load shifting or control i) Reduced capacity charging where peak capacity demand is reduced or lower than the average for that customer class ii) Reduced usage charges where demand is reduced or shifted to lower cost periods *Materiality as above.*	Customer	Potential bill increases arising from time of use pricing, ie, for customers who have greater than average peak consumption and who cannot shift this consumption	Customer
Facilitates time of use pricing thereby better ensuring that customers are paying for the costs they impose on the network (subject to any tariff side constraints or reassignment restrictions) *Material impact where such prices better ensures enhanced network utilisation, and peak demand growth at a rate that reflects revenue growth.*	DNSP		
Facilitates network connection capacity charging pricing thereby better ensuring customer are paying for the costs they impose (subject to any tariff side constraints or reassignment restrictions) *Material impact where such prices better ensures enhanced network utilisation, and peak demand growth at a rate that*	DNPS		

Potential benefit ***Materiality***	**Benefit recipient**	**Potential costs** ***Materiality***	**Bearer of costs**
reflects revenue growth.			
Revenues for AMI meter provision *Immaterial as cost and benefit should be aligned via regulation of AMI revenues.*	DNSP	Capital expenditure for meter provision *Immaterial as cost and benefit should be aligned via regulation of AMI revenues.*	DNSP
Improved system reliability and safety management through real time consumption data at point of use *Materiality will depend upon the specification of service incentive rewards and penalties.*	DNSP	Additional data and communications management *Immaterial as such costs should be allowed for in regulated AMI revenues.*	DNSP
Enhanced end-use customer consumption information to aid: i) energy purchase and hedging decisions ii) NEMMCO generation scheduling decisions	Retailer Generators/NEMMCO		
Network capital expenditure deferral achieved through load shifting and reduced growth in peak demand *Materiality will depend upon the:* - *ability for DNSPs to implant efficient price signalling* - *retailers' willingness to pass on such signalling* - *responsiveness of customers' demand* - *firmness of customers' response*	DNSP	Lost/reduced opportunity for business expansion	DNSP
Ability to complete final customer meter reads and implement new connections more rapidly *Materiality will be determined by the difference between the current cost of sending a network staffer out for the final meter read, meter disconnection and meter reconnection, and the additional cost of AMI roll out.*	DNSP/Retailer	Smoother customer churn processes	Retailer/customer

3.2. Implications for rule development

The realisation of the benefits made possible via AMI roll out requires that DNSPs are able and motivated to structure their prices more efficiently to end use customers and so other electricity supply chain participants are able to make use of the enhanced data and load control functionality provided by this infrastructure.

Where retailers cannot gain reasonably priced access to direct load control functionality, many of the retail benefits of AMI roll out will be forgone. Similarly, to the extent that AMI infrastructure is not owned by DNSPs, lack of reasonably priced access to direct load control functionality may also prevent the realisation of related network benefits (such as enhanced 'firmness' of DSR).

3.2.1. Regulatory or rule impediments

Currently and under the initial Rules (as currently specified) there are a number of rules that prevent the DNSP from setting efficient capacity-based time of use (TOU) prices and from ensuring that customers are reassigned to a TOU tariff upon installation of AMI. The requirement for DNSPs to be able to price their provision of network capacity and services means that several aspects of the current rules may limit the extent to which the full benefits of AMI are realised, including:

§ Tariff side constraints which may prevent DNSPs from introducing or rebalancing effective TOU and load control tariffs in a timely manner. This is arguably a greater concern under the initial Rules, which seek to impose more stringent constraints than are currently applied by any jurisdictional regulators (see Appendix A). Limitations on DNSPs' ability to set efficient TOU tariffs will tend to reduce their incentive to reassign customers to such tariffs upon installation of AMI at the customer's connection point.

§ Many of the network benefits of AMI will be forgone where DNSPs are unable to assign customers to a tariff that reflects the enhanced metering capability of AMI, eg, via ability to meter energy by its time of use or to meter capacity demand. Thus a potential regulatory impediment arises from tariff reassignment regulations that prevent DNSPs from reassigning customers to tariffs capable of delivering the benefits intended through AMI and direct load control without prior customer consent, eg, as was the case in Victoria prior to the 2006-10 electricity distribution price determination. Provisions for mandatory tariff reassignment following installation of AMI may be necessary as some customers who have greater than average consumption during peak times may face bill increases and may therefore be unwilling to consent to reassignment (see further discussion in section 7.8.2 of Part One). Further, requirements for consent add to the administrative costs incurred in implementing the facilitating tariffs.

§ There is currently a lack of clarity regarding the regulatory arrangements for AMI - most importantly, this surrounds the question of whether or not it is envisaged that competition may be promoted in the provision of metering assets, while at the same time mandating a roll-out of the meters. Moreover, while Victoria has sought to develop a regime for the cost recovery of AMI rolled-out in that state, the extent of certainty that it can provide investors in these assets is necessarily limited by the fact (or expectation) that at some time a national regime will replace the state regime, as well as from the lack of clarity at the national level as to the role that competition in the provision of these assets is expected to play in the future.

Additional regulatory impediments to the realisation of AMI benefits that are beyond the scope of this review of the revenue and pricing Rules may arise from:

- Technical meter specifications that may also impede the roll out and benefits obtained from AMI. For example, requirements for all installed meters to have manual read capability have delayed Energy Australia's AMI trial even though all other aspects of the metering (ie, including remote meter reading capability) were operational.

- Retail price regulation may prevent retailers from passing TOU network tariff signals onto customers. However, the extent of such constraint will depend upon the form of retail price regulation. The network plus retail ('N+R') form of regulation applied in NSW can be expected to allow retailers to pass through TOU pricing by DNSPs.

3.2.2. Recommendations

AMI offers significant potential market benefits by enabling more efficient pricing structures. To ensure the benefits of AMI are maximised, it may be desirable to implement the following requirements within the Rules:

- Require DNSPs to reassign customers to TOU tariffs following installation of AMI (see section 7.8.2 of Part One);
- Further work may be warranted to investigate whether DNSPs should be required to establish client relationships with their customers for the purpose of educating them about the costs of network constraints and so the potential benefits of DSR. The question of who is best placed to service this educational role (out of DNSPs and retailers) should be part of this consideration (see section 9.2.3 of Part 1); and
- Owners of AMI should be required to provide access to the direct load control infrastructure to retailers, DNSPs, TNSPs and other DSR intermediaries where the customer has been charged via a TOU or interruptible supply tariff, and the AMI is capable of providing such functionality.

These measures will assist to ensure the network and retail level benefits of AMI are realised.

Box 3.1
Rule Recommendations

- DNSPs should be required to reassign customers to a time of use tariff following installation of advanced metering infrastructure at the customer's connection point.

- Reassignment should be accompanied by a requirement for customer education regarding ways in which they can manage their demand to affect their bill. Further work is required to identify whether this is a role best served by retailers or DNSPs.

Box 3.2
Recommendations for consideration beyond the revenue and pricing Rules

- Where a direct load control facility is available at a customer’s connection point, consideration should be given to ways to ensure the controller of this infrastructure provides access (on reasonable or regulated terms) to that customer’s retailer, DNSP, TNSP or other DSR intermediary engaged by the customer for the purposes of load control.

3.2.3. Implications arising from the proposed national framework for network connection arrangements

While there are unlikely to be specific implications arising from the proposed network planning and connection charging frameworks in relation to an AMI program, there is one implication arising from the proposed recommendations on a framework for network connection arrangements.

Specifically, allowing a connection agreement to be modified without reviewing all elements of the agreement will simplify the process for including active load control measures that may become possible through the implementation of AMI, into the agreement.

4. Large user with DG that requires back-up connection

Customer-installed distributed generation or DG may provide an effective means of reducing that customer's reliance on energy imports. The reduced consumption of grid-provided energy reduces the customer's energy usage bill component. In this case, the large user has installed DG for most of its power needs, but requires ongoing back-up connection for its residual demand, and stand-by power when the DG is off-line. The requirement for a back-up (or stand-by) connection means the DG may not necessarily have a significant impact on the customer's network capacity requirement and therefore may not lead to a reduction in network charges.

In many ways, this case may be viewed as a larger scale version of the large scale PV roll out in that in both instances, the customer is effectively only reducing its demand for network delivered energy part of the time. In these instances, the residual demand for network capacity will be the driver of network costs and associated charges. If the peak capacity requirement does not differ from that required absent the DG, the network costs caused by the customer would be unchanged, and hence it would be efficient for its capacity-related network charge not to reduce as a result of installing the DG.

Examples of large users installing DG to meet most of their energy needs can be found in the large sugar mills of Queensland. Ergon Energy advises that a number of such mills have DG capacity installed on their premises to assist during the crushing season. While capable of generating moderate amounts of energy (up to 5MW) these generators tend not to run continuously, requiring down-time for maintenance (at least weekly), during which periods the customers draw entirely on the network for their energy needs.

These down-times therefore drive network costs in terms of the capacity that must be made available to the mills. Furthermore, variations in the level of export output from these mills can have impacts on the configuration requirements for the network. Consequently, Ergon Energy charges large users with DG the same tariffs as it charges other large users on the basis that 'whether importing or exporting, they are using the infrastructure to transport energy.' Arguably, this places DGs at a competitive disadvantage to transmission-connected generators who only pay shallow connection charges. Following the disaggregation of the Queensland energy supply system, DGs are now able to negotiate with Queensland retailers to receive some form of payment for their exported energy.

4.1. Costs and benefits

The benefits of DG primarily accrue to the customer owning the DG by means of reduced delivered energy charges. If there is a requirement for ongoing back-up connection and no commitment from the customer as to the availability of the unit, then the DNSP would be unable to defer network augmentation due to the lack of 'firmness' in the energy exporting capacity of the DG. Similarly, the need to maintain stand-by capacity to meet the customer's energy consumption needs implies that no network costs would be avoided. DNSPs can only rely on customer installed DG energy exports or covering all of the customer's energy demand where it is guaranteed at times of system peak. Moreover, where a large customer has back-up or residual demands on the system, the DNSP must make sufficient capacity available to meet the customer's back-up consumption needs, regardless of whether this capacity ends up being used at peak times.

Absent a guarantee by the customer that it will export at peak times, or (at least) that it will not draw on the network for its back-up consumption needs at these times, the DNSP will be compelled to proceed with network augmentations and thereby negate any benefit that may have arisen from the DG installation.[11]

Retailers will benefit from savings in distribution losses. These savings can be calculated as the product of the amount of energy generated by the DG and the applicable distribution loss factor (DLF). However, the value of these saving is likely to be immaterial given the averaging that occurs in the calculation of DLFs, and the fact that, generally speaking, user-installed DG produced energy accounts for less than the currently accepted error margins in DLF calculations.

[11] Note this compulsion will be lessened where DNSPs are permitted to conduct their network planning on a risk management basis and where service incentive arrangements are based predominantly on willingness to pay rather than prescribed standards such as ‘n-2’.

Table 4.1 Summary of benefits, costs and affected parties

Potential benefit ***Materiality***	**Benefit recipient**	**Potential costs** ***Materiality***	**Bearer of costs**
Reduced demand for network delivered energy *Materiality will depend upon the share of the DG customer's demand that is met by its DG energy generation.*	DG customer	Forgone revenue *The materiality will depend upon the extent to which a DNSP's charges are weighted towards usage charges relative to capacity charges.* *Consequences will be greater for price cap regulated DNSPs due to forgone revenue impact.*	DNSP
Potential savings in energy purchase needs at peak spot price times	Retailer	Forgone margin, hedge book imbalance *Hedge book imbalance is likely to be immaterial because a short-term hedge book imbalance could be either a cost or a benefit depending on the direction of imbalance and the spot price at the time.*	Retailer
Potential savings in reduced need for generation augmentation	Generators	Forgone sales *Materiality depends upon relative growth in customer energy demand and installation of user-installed DG capacity.*	Generators
		Capital costs i) DG infrastructure ii) Inverters iii) Metering infrastructure	DG customer (whether metering costs are borne by the DG customer or the DNSP varies by jurisdiction)
Provision of back-up supply guarantee *Material where the customer is charged on a capacity basis, immaterial where this is not the case.*	DG customer	Stand-by capacity i) Network capacity charge (distribution and transmission) *Immaterial where the customer is charged on a capacity basis, material where this is not the case.* ii) Generation (when back-up capacity is used) *Immaterial as costs captured in the wholesale energy price.*	DG customer
Revenue from capacity provision *Material where the customer is charged on a capacity basis, immaterial where this is not the case.*	DNSP	Provision of stand-by capacity *Immaterial where the customer is charged on a capacity basis, material where this is not the case.*	DNSP

Potential benefit ***Materiality***	**Benefit recipient**	**Potential costs** ***Materiality***	**Bearer of costs**
Potential coincident peak demand reduction *Materiality depends upon metering arrangements as this only provides a benefit where the customer faces capacity charges and such charges are efficiently reviewed and reset on a periodic basis.*	DG customer		
Export energy into the network (only provides a benefit where the customer receives a payment for exported energy, which for large users is usually determined via negotiation between the customer and their retailer) *Materiality will depend upon the energy purchase value agreed between the retailer and DG customer*	DG customer		
Potential for deferral of network augmentations arising from: i) Coincident peak demand reduction (only where this can be relied upon for all peak times) ii) Energy export at times of peak demand (only where this can be relied upon for all peak times) *Materiality will be determined by the level of network constraint in the network location that the DG customer is connected to, and the 'firmness' of the network support offered by the DG.*	DNSP		
Avoided TUOS payments (the current rules require avoided TUOS charges to be paid to embedded generators – however it is not clear that these are being paid to users who have DG so much as they are being paid to dedicated generation assets connected to the distribution network – this varies by jurisdiction) *Materiality directly determined by whether the DG customer receives an avoided TUOS payment from their DNSP, and whether this is passed on by their retailer.*	DG customer	Double incidence of avoided TUOS payments without any corresponding DNSP benefit (see Table 2.1)	DNSP
		Ongoing maintenance	DG customer
		Compliance with system protection and safety protocols or additional connection asset costs	DG customer
		System protection, reconfiguration and reinforcement (to the extent that these costs are not passed on directly to the customer in its connection charge)	DNSP

4.2. Implications for rule development

The alignment of costs and benefits for customer DG installation will provide for efficient outcomes only where DNSPs are able to set efficient price structures to end use customers. Setting aside the natural instinct of a business to seek growth opportunities, DNSPs will be:

§ largely indifferent to DG infrastructure relative to network infrastructure, providing they are able to set prices that reflect the (capacity-related) cost of providing stand-by (or back-up) capacity to customers; and

§ more motivated to encourage DG infrastructure where they have the ability to set prices that are efficient and the ‘firmness’ of a given DG option is sufficient to alleviate an identified network constraint and/or facilitate deferral of network expansion.

4.2.1. Regulatory or rule impediments

Various aspects of the current and proposed initial rules can be expected to impede DNSPs’ ability to price the network capacity they supply to DG customers efficiently, and thereby distort the relative incentives as between DG infrastructure and network infrastructure. Specifically:

§ Where network planning (or service reliability) standards are highly prescriptive, this may limit DNSPs’ ability or willingness to rely upon non-network solutions – because of the inherent lack of firmness of DG, relative to deterministic planning standards such as n-2;

§ The negotiate and arbitrate form of control is triggered for most DG’s connection to the distribution network by the fact that this connection requires non-standard service provision by the DNSP. However the DGs generally have limited countervailing buyer power and may therefore potentially be disadvantaged in the negotiation process. This gives rise to the need for additional regulatory scrutiny of DNSPs’ negotiating frameworks in order that checks and measures are included to balance any potential market power (see section 8.3 of Part 1).

§ Tariff side constraints may prevent DNSP from introducing financially rewarding yet capacity cost reflective DG tariffs in a timely manner. This issue arises because ongoing user-installed DG charges would fall under the direct control form of regulation once any specific connection charges have been negotiated.

§ Tariff reassignment constraints may prevent the DNSP from reassigning customers to the DG tariff (either at all or without prior customer consent).

§ The rules do not require DNSPs to review capacity usage and utilisation on a periodic (albeit infrequent) basis. While DNSPs in some jurisdictions have established and published protocols for assessing and reviewing capacity demand and charges, this is not the case with all DNSPs, thereby leading to customer confusion and frustration at their inability to affect change in their capacity charges.

4.2.2. Implications

At a network level it will always be efficient for a DNSP to charge the customer for the capacity that it is required to make available. If the DG's potential to export or meet the customer's energy needs is not 'firm,' then a DNSP will arguably derive little benefit from its installation. The 'firmness' of DG as a form of network support will, however, increase as more DG units are installed in a given location.

For example if three manufacturers in an industrial estate all install DG, then the risk that there will be no network support is reduced at any given time. This will increase the 'firmness' of the network support, and may enable the three customers to collectively enter into a network support agreement with the DNSP when an augmentation otherwise would be required in return for establishing protocols such that at least one of the DG units will always be running (or at least during weekday business hours). Alternatively, a DG customer may agree to not operate certain plant and equipment at times when its DG is off-line such that its capacity reduction can be assured.

It is efficient to charge for the provision of network capacity given its role as a major determinant of network costs (see chapter 3 of Part One), and even to weight tariffs more heavily towards capacity charging than usage charges given their relative contribution to costs. However, efficient customer response will only be elicited where customers can affect a change in their charges by altering their capacity demand, eg, by means of the examples provided above. To assist in motivating customers to enhance the 'firmness' of their capacity demand reduction, DNSPs should be required by the distribution pricing rules to publish protocols for the revision and resetting of capacity charges.

These protocols should be approved by the AER as part of annual tariff approval processes and should set a maximum period between a customer affecting a capacity demand reduction, and their network capacity being adjusted accordingly. This maximum period may be set at say 12 months (the period currently used by several DNSPs who have published protocols)[12] in order to ensure that the customer has made a permanent capacity demand reduction. This issue is considered further in section 7.9 of Part 1.

The capacity assessment reset period should be reduced (or the review made immediately) in circumstances where the customer installs load management infrastructure (approved by the DNSP) which is capable of guaranteeing the capacity reduction.

Where capacity charges are not efficiently reviewed and reset, a disconnect will arise between the benefits accruing to DNSPs and the costs incurred by customers in implementing DG (or DSR) solutions.

Additional implications for rule development may differ depending upon the size or density of DG customers and their residual demand for back-up connection. While it is efficient for DNSPs to charge for the capacity they make available to the DG customer, there may be situations where it is also efficient for them to pay the DG for network support. These

---

[12] Note this is also the period currently applied for the updating of distribution loss factor calculations (see clause 3.6.3).

situations will arise where the network support is sufficiently 'firm' as to enable the DNSP to meet its planning and reliability requirements.

Where a DG is of sufficient scale to provide effective network support, or there are enough smaller scale DG customers in a given area to increase the 'firmness' of network support to acceptable levels, then these customers may reasonably be expected to negotiate with their DNSP for network support payments.

DG customers may also benefit from entering into agreements with their retailers to sell energy they export into the grid. Due to the scope to reduce their wholesale energy purchases and benefit from avoided network losses, retailers will likely be motivated to pay DG customers up to the value of these two benefits (see section 8.2.2 of Part One).

To maintain a competitively neutral regulatory treatment for transmission-connected and distributed generators, the Rules should prevent DNSPs from charging DGs a positive usage charge for energy exported into the grid. Absent such a rule, DGs will be at a competitive disadvantage relative to other, transmission-connected forms of generation (see chapter 8 of Part One).

4.2.3. Recommendations

The above implications give rise to the following suggested Rule elements:

- Tariff side constraints should be specified in a manner that strikes a balance between the need for DNSPs' to price efficiently and the associated implications of effective DG valuation and utilisation, and the desire to manage the transition to more efficient pricing.
- DNSPs should be required to submit to the AER for approval and to publish protocols for the assessment of capacity demand and determination of capacity charges including:
  - the period over which capacity demand will be reassessed before capacity charges are reset (this should be limited to say 12 months); and
  - a list of approved load management infrastructure that once installed, and notified to the DNSP, will trigger an immediate capacity charge reset.
- DNSPs should be prevented from charging a positive usage charge on DG exported energy in order to ensure equal treatment with transmission-connected generators.

Box 4.1
Rule Recommendations

- The requirement for the periodic review of side constraints should be retained in the initial Rules.
- DNSPs should be required to submit to the AER for approval and publish protocols for the assessment of capacity demand and determination of capacity charges including:
  - the period over which capacity demand will be reassessed before capacity charges are reset (say, every 12 months).
- The initial Rules should not permit DNSPs to levy on DGs either positive DUOS charges for energy exported to the grid or deep connection costs.

Box 4.2
Recommendations for consideration beyond the revenue and pricing Rules

- It is important that jurisdictional standard setters be cognisant of the DSR and DG incentive implications of network planning or service reliability standards. Consideration should be given to the use of probabilistic standards and their relative costs and benefits as compared with deterministic standards.

4.2.4. Implications arising from the proposed national frameworks for electricity distribution network planning, network connection arrangements and connection charges

4.2.4.1. Implications arising from the proposed national framework for network planning

Under the proposed national framework for network planning, a mechanism will exist whereby a large customer with DG that requires back-up connection could offer DSR and/or generation export into the grid in return for payment if it were likely to reduce peak capacity and make possible the deferral of a network augmentation.

Information on emerging constraints will be made available through two channels:

- the annual planning report; and
- the detailed request for proposals (RFP) issued by a DNSP when the network solution would require an estimated capitalised expenditure of $2m or more.

These planning documents should remove information asymmetries between distributors and providers of demand management solution by making available:

- sufficient information early enough in the planning process to identify where such a scheme could potentially alleviate a constraint and lead to the deferral of a network upgrade;

- the distribution loss factor (current and forecast) that applies in the area of the constraint and which is therefore likely to apply to the DG (see 4.2.4.4 for the implications of the loss factor); and
- information on the value of a deferral (in terms of $ per kVa per annum) and therefore the funds available for non-network solutions.

A DNSP will face a requirement to evaluate all proposals it receives on an equal footing, using clear and transparent criteria, and to publish the results of its analysis. Where DG represents an efficient supply option this process should provide a mechanism for it to receive equal treatment with other options. A process will also exist for this analysis to be reviewed by an independent third party.

To overcome regulatory impediments that potentially undervalue the efficient utilisation DG, this evaluation process would involve a cost-benefit analysis that explicitly includes the wider network benefits – such as reduced losses – that DG supplying into the network could potentially offer. However, as with the case of the PV roll-out, a large user offering to reduce demand and/or supply DG into the network would need to satisfy the DNSP – to a reasonable standard – that generating capacity would be available when required and coincide with the network's peak capacity load.

4.2.4.2. Implications arising from the proposed national framework for network connection arrangements

The large user with DG that requires back-up connection will also benefit from the inclusion of the small and medium technical requirements in the Rules, the streamlining of the connection process and the greater clarity provided by the single negotiation framework for standards, prudential requirements and where relevant connection charges.

4.2.4.3. Implications arising from the proposed national framework for connection charges

A large user with DG that is supplying power for its own consumption will not be affected by the proposed framework, as it would not be connected the DG to the shared distribution network, as it would only reduce the demand for energy for its own use.

However, if it also exported energy during some periods thereby requiring connection to export to the network, then as for a mid-sized distributed generator, it would benefit from not being required to fund any upstream augmentation that might be required to the shared network. This also ensures that it is placed on a competitively neutral footing compared with generators connected to the transmission network.

Clarifying charges for connecting a DG constructed by a large user to the network will ensure that large users take the possibility of selling energy into the network at certain times into consideration when making a DG investment. The framework ensures that the costs are limited to the provision of any dedicated or extension assets necessary to connect the large user's DG to the network.

4.2.4.4. Implications arising from the proposed national framework for distribution loss factors

A large user with DG that requires back-up connection will enjoy the same benefits from the proposed framework for distribution loss factors as apply to a large scale PV roll out (see section 2.4.3.4 above).

5. Mid-size DG supplying peak power & network support

Distributed generation or DG provides an alternative to base-load generation that tends to be located large distances from users. Because DG is located closer to the point of consumption and connected directly to the distribution network rather than the transmission network, it requires less network transportation capacity, is likely to involve reduced losses, and may be used to assist in the economic deferral of some network augmentations or reduction in energy losses.[13]

DGs that produce less than 5MW of energy may follow several paths in order to derive value from this production including:

§ negotiating to sell this energy to a local retailer with no NEMMCO involvement;

§ negotiating to sell this energy to a local DNSP with no NEMMCO involvement;

§ entering arrangements with a licensed generator whereby that party manages the NEMMCO interface on the DG's behalf; or

§ registering with NEMMCO as a market participant and being paid directly by NEMMCO for meter energy exports.

All DGs above 30MW are required to be registered with NEMMCO and to have their load scheduled[14].

The case study under consideration in this chapter is of a mid-sized DG supplying peak power and network support that is capable of deferring network expansions. For our purposes (ie, assessing the distribution revenue and pricing rules) it is irrelevant as to which of the above paths the DG has taken to sell its energy.

By way of example, Infatil's Lonsdale Power Station in South Australia has been contracted to provide network support for ETSA Utilities. Similarly, some DNSPs have entered into collaborative arrangements with other DNSPs or related parties to establish DG (and EG) facilities. An example of this is the gas-fired Somerton Power Plant in Victoria which is owned and operated by AGL Power Generation, and receives avoided TUOS payments from two DNSPs, AGL Electricity and SPAusnet.

Furthermore, many DNSPs own their own movable DGs, which they use as temporary solutions to network constraints when they are short of the necessary resources to undertake the network augmentation or to allow additional time for planning of network solutions. For example, Ergon Energy owns a number of DG units that it uses for mining sites while the network infrastructure to bring grid energy to the site is being constructed.

---

13 Distribution losses are energy losses incurred at the distribution level. These account for approximately 10% of delivered energy.

14 An exception to this requirement exists for large scale intermittent load such as wind farms.

There has also recently emerged an intermediary, Energy Response, that provides DG scheduling and aggregation services to DNSPs and TNSPs. This intermediary enlists customers with back-up DG and pays them to provide scheduled (by NSPs not NEMMCO) generation for network support.

5.1. Costs and benefits

The benefits of a mid-size DG supplying peak power and network support capable of deferring network expansions are substantial as evidenced by:

- the contracting of such network support that has occurred in most jurisdictions;
- DNSPs' own use of DGs as short-term solutions to network constraints; and
- the emergence of intermediaries to provide scheduled and on-call network support from various back-up DGs installed in commercial premises.

The extent to which network deferrals will be facilitated by a mid-sized DG facility will be influenced by the:

- 'firmness' of the peak generation capacity (ie, the reliability of generation at times when the DNSP calls upon it);
- pace of growth in customer demand in the locality; and
- cost of the generated energy and the generator infrastructure relative to grid energy and a network solution.

For example, while Ergon Energy uses diesel-fired DG units to initially meet the energy needs of new mining sites, these are rapidly replaced with network connections due to the relatively high cost of diesel fuel.

A substantial cost for DNSPs arising from DG is the double incidence of avoided TUOS payments without any commensurate benefit in avoided or deferred TUOS costs (i.e., in situations where avoided TUOS payments are not able to be passed through the remainder of the customer base).

DGs are also likely to affect the costs and benefits of network losses through:

- the displacement of more distant transmission-connected generation;
- a reduction in losses through more efficient utilisation of the distribution network; and
- the reduction in retailers' purchases of energy (and its associated loss factors) from outside sources.

Table 5.1 Summary of benefits, costs and affected parties

Potential benefit ***Materiality***	**Benefit recipient**	**Potential costs** ***Materiality***	**Bearer of costs**
Network support payments *Materiality will depend upon the firmness of the DG output or reduction in customer demand at peak times, the location of the DG and extent to which this coincides with a network constraint, and the scale of DG output or customer load reduction at peak times.*	DG owner	Network support payments *Immaterial because payments are specified by reference to the associated benefits.*	DNSP / TNSP
Potential savings in reduced need for transmission-connected generation augmentation	Generators	Forgone sales *Materiality depends upon relative growth in customer energy demand and installation of DG capacity.*	Generators
Avoided TUOS payments (the current rules require avoided TUOS charges to be paid to embedded generators) *Materiality will depend upon the scale of substitution of DG energy for transmission delivered energy at peak times and the value of TUOS charges levied on the relevant DNSP at the relevant transmission connection point.*	DG owner	Double incidence of avoided TUOS payments without any corresponding DNSP benefit (see Table 2.1)	DNSP
Export energy into the network (only provides a benefit where the DG receives a payment for exported energy –ie, where the load is scheduled, payment has been negotiated with a retailer, or the DG is registered with NEMMCO) *Materiality will depend upon the:* *i) energy purchase value agreed between the retailer and DG ; or* *ii) wholesale energy spot price; and* *iii) any network support payments agreed between the DG and relevant DNSP and/or TNSP*	DG owner	Payment for exported energy *Immaterial because payments are specified by reference to the associated benefits.* Capital costs i) DG infrastructure ii) Inverters iii) Metering infrastructure (varies by jurisdiction as to whether this costs is borne by the customer) *Can be material depending upon the form and scale of generation installed.*	Retailer / NEMCO / DNSP DG owner
Payment for network connection costs	DNSP	Connection costs (established via negotiation with the DNSP) *Materiality will depend upon the extent to which deep connection costs satisfy the regulatory test, and negotiated connection charged outcomes.*	DG owner

Materiality will depend upon whether deep connection costs satisfy the regulatory test.		Network connection costs such as system protection, reconfiguration and reinforcement (to the extent that these costs are not passed on directly to the customer in its connection charge)	DNSP
		Compliance with system protection and safety protocols	DG owner
		Ongoing maintenance	DG owner
Network augmentation deferral where DG provides coincident peak demand reduction by energy exports at times of peak demand *Materiality will depend upon the firmness of the DG output or reduction in customer demand at peak times, the location of the DG and extent to which this coincides with a network constraint, and the scale of DG output or customer load reduction at peak times.*	DNSP	Provision of stand-by capacity *Materiality will depend upon the extent to which these costs are passed on to the DG in its capacity charge where the DG requires back-up connection (eg, to power-up the generator following periods of being off-line for maintenance)*	DNSP
Network reliability improvements *Materiality will depend upon the firmness of the DG output or reduction in customer demand at peak times, the location of the DG and extent to which this coincides with a network constraint, and the scale of DG output or customer load reduction at peak times.*	DNSP / Customers		
Saving in network losses *Materiality will depend upon the level of avoided transmission losses and any reduction in distribution losses. Since losses account approx. 10% of NEM energy, this is likely to be highly material.*	Retailer	Forgone sales for transmission-connected generators	Transmission-connected generators

5.2. Implications for rule development

The efficient valuation and utilisation of DG will be influenced by:

- the 'firmness' of such generation at times of coincident peak demand;
- the extent to which efficient connection charges or payments can be fairly negotiated; and
- the ability for DNSPs to have network support payments recognised in regulatory revenues so as to give unbiased incentives for choices between network (capital) and non-network expenditure.

Further facilitation of DG will arise from the provision of network constraint information in a timely manner that enables DG proponents to identify opportunities to provide support to network service providers.

5.2.1. Regulatory or rule impediments

The following regulations and rules are likely to act as impediments to the efficient valuation and utilisation of DG:

- Current requirement for DNSPs to pay avoided TUOS payments to DGs may create incentive for DNSPs to avoid connecting DGs to their network in instances where they are unable to pass through the costs of avoided TUOS payments on to customers. This arises because:
  - such costs may effectively be incurred twice by DNSPs;
  - the TUOS charges are not actually avoided due to the application of revenue caps to TNSPS; and
  - the relatively lumpy nature of transmission network augmentation may further limit the extent to which transmission costs are avoided over successive regulatory periods (see section 8.4 of Part 1).

  Further, this requirement may permit DGs to be rewarded twice for deferring transmission network augmentations, ie, once through the avoided TUOS charge and again if a network support payment is able to be negotiated thereby offering an undue advantage relative to transmission-connected generators.

- Tariff side constraints which may prevent the DNSP from introducing a financially rewarding, yet viable, DG tariff in a timely manner. This only applies to the extent that the DG is also a DUOS user.

- Where the DG is solely a generator, DNSPs should be able to negotiate network support payments; however, their incentive to do so will be directly affected by the way such payments are recognised in the DNSPs' regulated revenues. Unless the incentives arising from the treatment of either form of expenditure are neutral, DNSPs' willingness to make network support payments (see section 5.2 of Part One) may be impeded.

- Relative incentives for operating expenditure and capital expenditure under the building block form of control may cause DNSPs to favour capital expenditure (ie, network expansion) over operating expenditure (ie, network support payments to the DG). This may arise from different efficiency incentives for operating expenditure and capital expenditure, including through the existence of a regulatory WACC that is greater than the DNSP's own (or perceived) WACC (see section 5.2 of Part One). Accordingly, at least in the short term, resort to scrutiny of planning decisions (ie, through the regulatory test process) will be required.

- Deterministic network planning and or service standards may limit DNSPs' ability or willingness to rely upon non-network solutions that have a lower level of 'firmness' than network solutions. These may be overcome by greater use of probabilistic standards (see section 6.2 of Part One).

- Poorly calibrated service reliability incentive arrangements (ie, targets, penalties and rewards) may contribute to the DNSP's unwillingness to rely on non-network solutions that have a lower level of 'firmness' than network solutions or may not sufficiently motivate improvements in service levels that may be efficiently achieved through DG (see section 6.1 of Part One).

- Service incentive arrangements may prevent DNSPs from contracting out liability for service performance in instances where third party providers of non-network service solutions such as DG are engaged to provide network support.

- Lack of competitive neutrality in the rule treatment of DG connection charges relative to transmission-connected connection charges may impede efficient decisions regarding optimal generation investment. Specifically, current rules differ in the incidence of 'deep' connection costs.

- DG's are likely to contribute to a significant reduction in distribution (and potentially transmission) losses, but the potential for this to be recognised and then to be rewarded is problematic (see section 8.2.2.3 of Part One).

5.2.1.1. Network planning regulations

DNSPs may face incentives to favour network solutions over non-network solutions such as DG as a result of differences in the regulatory revenue incentive placed on operating expenditures (such as network support payments) and capital expenditures (such as network augmentations). However, as discussed in sections 5.4 and 6.2 of Part One, these incentives may also arise from, or be exacerbated by, deterministic network service and planning standards.[15]

These factors may motivate DNSPs to withhold information from the DG market regarding emerging network constraints in order to:

- reduce the efficacy of DG investments, and thereby increase the case for greater use of network solutions and/or reduce the case for network support payments; or

---

[15] See NERA January 2007, DSR and DG Rules Review, sections 4.2 and 4.4.

§ to advantage their own related party DG providers.

In light of these potential incentives, a number of jurisdictions have established network planning and reporting requirements that require DNSPs to provide information to the market in a timely manner regarding emerging constraints, and in some instances to publish requests for proposals for non-network solutions to such constraints.

For example, South Australia requires ETSA Utilities (ETSA) to publish an Electricity System Development Plan annually that identifies network constraints likely to arise over a three year horizon. In addition, ETSA is also required to publish a request for proposals for alternative solutions to all network constraints with a capital cost of more than $2 million. To date, 12 such requests have been published with only three proposals having been submitted, none of which were adopted by ETSA. Guideline 12 was recently revised by ESCOSA and ETSA is now only required to issue a request for proposal if a network solution is expected to cost more than $2 million and if it concludes that a non-network project is likely to be economically viable or technically feasible. If a proposal pass this 'reasonableness test' then ETSA Utilities is required to publish a comprehensive request for proposal.[16]

5.2.1.2. Negotiated DG connection charges

DG connection charges can be expected to fall under the negotiate and arbitrate form of regulation. This is generally by virtue of the relevant connection services being of a non-standard nature, rather than because of the systematic existence of significant countervailing or buyer power. It follows that DNSPs are likely to retain a degree of market power capable of adversely affecting negotiated outcomes. Measures to balance this potential market power are discussed in section 8.3 of Part 1 and include a requirement for DNSPs to submit a negotiating framework to the AER for approval.

However the current regulatory arrangements give rise to some important barriers to DG through the incidence of shallow and deep connection costs.[17] Transmission-connected generators are only obligated to pay for shallow connection costs. Deep connection costs that satisfy the regulatory test are met by transmission customers (load). When any deep connection costs don't satisfy the regulatory test, the generator may either pay these (with no firm right to the resulting enhanced energy transfer capability) or face being constrained in its energy export capability (through NEMMCO's scheduling arrangements).

In contrast, the current distribution Rules permit DNSPs to charge DGs for both shallow and deep connection costs. Moreover, a range of incentive and information asymmetry issues exist that may impede the efficient negotiation of DG connection charges. These are considered further in section 7.3 of Part One.

To ensure efficient investment in generation infrastructure, and that DGs are not disadvantaged relative to transmission-connected generation, the initial Rules should afford

---

[16] Essential Services Commission of South Australia, June 2007, Review of Electricity Industry Guideline 12: Demand Management for Electricity Distribution Networks – Final Decision.

[17] These costs are defined in section 8.2.1.1 of Part One.

DGs equal treatment regarding the incidence of deep connection costs. This is discussed in greater detail in our recommendations relating to a national connection charging framework.

Further, while TNSPs are not permitted to charge generators a usage charge for their energy exports, there is evidence that DNSPs are levying such charges on DG energy exports in some jurisdictions. Neutrality requires that the Rules prevent the negotiation framework from supporting the imposition of such charges.

5.2.2. Recommendations

To maintain an even regulatory treatment for both transmission-connected and distributed generators, it is necessary that the Rules:

§ prevent DNSPs from charging DGs a usage charge for energy exported into the grid;

§ apply equivalent treatment of deep connection costs to those applying to TNSPs;

§ do not require the payment of avoided TUOS charges, but instead retain provision for negotiation of network support payments between DGs and TNSPs and/or DNSPs.

Absent such rules, DGs are likely to be at a competitive disadvantage (or advantage in the case of avoided TUOS payments) relative to other forms of generation, with the consequential distortion in the optimisation of investment in competing forms of generation.

In addition to the neutrality argument above, because there is no direct benefit accruing to DNSPs from avoided TUOS payments, and these may be incurred twice, the rules should not require DNSPs to make avoided TUOS payments. Any network deferral benefits (either transmission or distribution) should be negotiated between the DG proponent and the relevant network service provider.

To counter potential incentives for DNSPs to withhold information from DG proponents (and other DSR proponents more generally) during connection negotiations, the initial rules should include requirements for DNSPs to publish annual network planning reports that identify emerging network constraints.

Box 5.1
Rule Recommendations

- Provision in the Rules for the inclusion of payments made by DNSPs for 'network support' expenditure in the derivation of the building block revenue requirements should be retained.
- The method for recognising network support payments in the derivation of the building block revenue requirement should provide unbiased incentives for the efficient substitution of network support for network augmentation.
- The initial Rules should not permit DNSPs to levy on DGs either positive DUOS charges for energy exported to the grid or deep connection costs.
- Voluntary payments from DGs to DNSPs should be permitted where a DG agrees to pay for upstream augmentations in order to increase energy transfer capability, in the same way that a transmission connected generator can pay for upstream augmentations for the transmission system.
- The Rules should retain a requirement for DNSPs to submit their proposed negotiating framework for DG connection charges to the regulator for approval and subsequent publication. The Rules should require the AER to be satisfied that this framework:
    - provides for a robust procedure for the negotiation of connection agreements, including information exchange;
    - requires DGs only to fund shallow connection cost, where shallow is defined as the nearest point of the existing shared distribution network; and
    - provides for DG proponents to be made aware of the options for the funding of deep connection cost or the connection constraint consequences of these not being funded (either by DG or customers), including measures to ensure the provision of sufficient information to apply the regulatory test so as to determine the extent of any appropriate user-funded network augmentation.
- The Rules should remove the requirement for DNSPs to make avoided TUOS payments to DGs.
- The Rules should continue to provide for both TNSPs and DNSPs to make network support payments to DGs, EGs, or DSR providers, where the planning and regulatory test obligations under the Rules establish that such non-network solutions represent the most efficient means of alleviating a network constraint.

Box 5.2
Recommendations for consideration beyond the revenue and pricing Rules

- It is important that jurisdictional standard setters be cognisant of the DSR and DG incentive implications of planning standards. Consideration should be given to the use of probabilistic planning standards and their relative costs and benefits as compared to deterministic standards.
- A review of the information requirements in Chapter 5 of the Rules is necessary to ensure that:

- DNSPs provide DG proponents with the information necessary to apply the regulatory test to a DG connection proposal
- DNSPS provide information on the emergence of network constraints as well as areas of substantial under-utilisation existing transfer capabilities in order to allow DGs to identify and sit in the best location by reference to:
  - alleviating network constraints (and potentially earning network support payments); or
  - maximising energy transfer capability without incurring additional deep connection costs;
- DG proponents reveal their intended energy export levels such that DNSPs can accurately assess deep connection costs and formulate any connection constraint conditions that are required to protect network performance where:
  - the DG does not satisfy the regulatory test; and
  - the DG proponent chooses not the fund the deep connection costs.

§ Further analysis be undertaken on whether the current treatment of losses is consistent with promoting efficient distributed generation.

5.2.3. Implications arising from the proposed national frameworks for electricity distribution network planning, network connection arrangements and connection charges

5.2.3.1. Implications arising from the proposed national framework for network planning

Under the proposed national framework for network planning, a mechanism will exist whereby a mid-sized DG supplying peak power and network support can be considered alongside both network and other non-network solutions to alleviate an emerging capacity constraint. Financial incentives can be made available to secure this generating capacity if it is likely to reduce peak capacity and make possible the deferral of a network augmentation.

Information on emerging constraints will be made available through two channels:

§ the annual planning report; and

§ the detailed request for proposals (RFP) issued by a DNSP when the network solution would require an estimated capitalised expenditure of $2m or more.

These planning documents should lower barriers to entry for DG proponents, by overcoming information asymmetries and making available:

§ sufficient information early enough in the planning process to identify where such a scheme could potentially alleviate a constraint and lead to the deferral of a network upgrade;

- the distribution loss factor (current and forecast) that applies in the area of the constraint and which is therefore likely to apply to the DG (see 5.2.3.4 for the implications of the loss factor); and
- information on the value of a deferral (in terms of $ per kVa per annum) and therefore the funds available for non-network solutions.

Furthermore, a DNSP will face a requirement to evaluate all proposals it receives on an equal footing, using clear and transparent criteria, and to publish the results of its analysis. Where DG represents an efficient supply option this process should provide a mechanism for it to receive equal treatment with other options. A process will also exist for this analysis to be reviewed by an independent third party.

To overcome regulatory impediments that potentially undervalue the efficient utilisation DG, this evaluation process would involve a cost benefit analysis that explicitly includes the wider network benefits – such as reduced losses – that DG supplying into the network could potentially offer.

5.2.3.2. Implications arising from the proposed national framework for network connection arrangements

As with the owners of PV cells, the mid-sized distributed generator supplying peak power and network support will benefit from the inclusion of technical requirements for small and medium DGs in the Rules, the streamlining of the connection process and the greater clarity provided by the single negotiation framework for standards, prudential requirements and where relevant connection charges.

5.2.3.3. Implications arising from the proposed national framework for connection charges

For a mid-sized DG, there are significant benefits arising from the proposed framework for connection charges. The removal of any requirement to fund upstream augmentation ensures that distributed generators are placed on a competitively neutral footing compared with generators connected to the transmission network.

In this example, the mid-sized DG would only be required to pay for connection assets from the connection point, as defined by the AER, to the DG. This is known as the dedicated assets. If an extension to the existing network is required to connect the DG, then these potentially shared assets would be fully paid by the DG, who would be entitled to recoup the costs of the extension assets in the event that subsequent users connect to the extension assets up to seven years from the initial commission of the assets.

Finally, there is unlikely to be a need for any shared network augmentation arising from this connection, because the mid-sized DG is providing network support services, thereby reducing the need for shared network augmentation. In any event, the framework would not require the mid-sized DG to pay for any shared network augmentation.

This framework thereby provides competitive neutrality between the mid-sized DG and generators connecting to the transmission network.

5.2.3.4. Implications arising from the proposed national framework for distribution loss factors

A mid-size DG supplying peak power and network support may enjoy benefits from the proposed national framework for distribution loss factors in addition to the settlement benefits described in the large scale PV roll out (see 2.4.3.4 above). This will depend on how it sells the energy produced. If it does so without NEMMCO involvement then there will be the described settlement benefits alone, and rather than obtaining the benefits directly from the pool it would need to negotiate with a retailer or other participant to obtain the benefits it creates. If, however, the DG enters into arrangements with a licensed generator whereby that party manages the NEMMCO interface on the DG's behalf, or registers with NEMMCO as a market participant and is paid directly by NEMMCO for meter energy exports, then there may also be benefits through an improvement in its place in the merit order for dispatch and the settlement amount that the generator is paid.

When determining which generators are dispatched, the NEM takes into account the losses incurred (or avoided) by embedded generators in (notionally) transporting energy to the regional reference node, including losses deemed to be caused (or avoided) on the distribution network. The use of a marginal loss factor rather than one based on average losses will improve the delivered price attributable to the DG (provided that it is in a position where it will avoid losses).

Similarly, the price that a scheduled embedded generator gets paid reflects the losses incurred (or avoided) when transporting electricity from the regional reference node to its transmission connection point and the quantum of energy for which it gets paid reflects the losses that it causes (or avoids) on the distribution network. The use of a marginal loss factor rather than one based on average losses will increase the units of energy for which the DG gets paid and hence will deliver a financial benefit (provided that it is in a position where it will avoid losses).

In summary, the creation or avoidance of losses on both levels of the network (transmission and distribution) is taken into account when determining the merit order of generators and settlement (i.e. losses affect what they get paid), which will advantage generators in load-rich areas. And moving the DG distribution loss factor to one based on marginal losses, and therefore probably increasing it from its current value, will augment these effects.

The inclusion of distribution loss factors in the DNSPs' annual planning reports should assist project proponents to respond to this important locational signal for planned DG investment.

6. Large DSR project to relieve CBD network constraints

A large scale DSR project to relieve growing network constraints in a central business district, such as direct load control of commercial air conditioners, has the potential for substantial network cost savings due to the service interruption costs, and the alleviation of significant congestion in utility infrastructure access points/corridors to CBDs.

These benefits will be realised where the DSR project is effective in reducing growth in peak demand, and shifting energy usage to increase the utilisation of existing network capacity.

An example of a large scale DSR project comes from Energy Response. Energy Response acts as a DSR aggregator providing load curtailment services to Transgrid via its Security Response Program. This program identifies and tests customers who have units of 100kw/h of interruptible load and then provides a scheduling mechanism for interrupting this load and paying customers for doing so.

SP AusNet in Victoria also provides an interruptible supply tariff (NEE54 Medium Demand Multi-rate Interruptible) although its network area does not include the Melbourne CBD.

6.1. Costs and benefits

Broadly speaking the benefits of installing a large DSR project to relieve CBD network constraints would accrue to DNSPs only where the DSR was well enough subscribed/aggregated to by large users and where the network support achievable through direct load control is sufficiently 'firm' as to enable deferral of CBD network augmentation. This 'firmness' would be significantly strengthened by the fact that the DNSP has direct control over the load, thus the key variable in terms of benefit is likely to be the scale of load that the DNSP can control at peak times.

Where the required scale is achieved, DSR projects can provide significant net financial benefits to DNSPs in regards to deferral of costly CBD network augmentations and associated outages. However, the extent to which DNSPs are motivated to realise these benefits will be affected by various expenditure incentives arising under the building block form of revenue regulation and associated service and cost efficiency incentive arrangements. These issues are considered in chapters 5 and 6 of Part One.

In the example of CBD direct load control, it is not clear that the benefits that accrue to commercial CBD customers via reduced tariffs are likely to outweigh the costs of forgoing the right to uninterrupted supply. This is because large CBD customers may well have less price responsive demand than may be the case in other areas, ie, because the contribution of energy costs to their bottom line may be smaller relative to say industrial users. However, by using AMI to directly control load (and therefore supply interruption) to specific appliances such as air-conditioners, DNSPs can reduce the impact of supply interruption on commercial users and in the case of air-conditioner load, can potentially have only marginal impact on the customer.[18] Moreover, growth in the market for customer aggregation and DSR services

[18] For example, under air-conditioner load control, it is likely that the supply of temperature management functionality will not be interrupted because the AC will be say switched off for 30 minutes with the fan still going, or the temperate

should facilitate enhanced targeting of load control to elements of commercial usage that have a lower marginal value to customers than does the marginal gain in network savings.

In such cases, it may be efficient for the customer to agree to have its load interrupted where the delivered energy price rises above a predetermined level. This may include interruption for:

- Wholesale/retail energy price spikes triggered by generation constraint; and
- Network congestion constraints that trigger payment of network support by the DNSP or trigger constraint of a customer's capacity allocation given its agreed/assigned capacity charge.

---

control (target) will merely be raised a few degrees for a short period to reduce the power to the compressor. Thus temperature is unlikely to increase materially.

Table 6.1 Summary of benefits, costs and affected parties

Potential benefit ***Materiality***	**Benefit recipient**	**Potential costs** ***Materiality***	**Bearer of costs**
Preferential tariff i) Lower capacity charge ii) Lower usage charge *Materiality depends upon the amount of interrupted load and the value of network or retailer savings.*	DSR participant	No longer have guaranteed supply *Immaterial as customer can choose what aspects of its load are subject to control.* Lower tariff revenue *Materiality depends upon the amount of interrupted load and the relative value of network savings.*	DSR participant DNSP
Ability to ensure energy is only used when priced at levels that are cost effective for the customer without having to actively manage their own usage (ie, by allowing the DNSP to manage this usage). *Materiality will depend upon energy cost contribution to customer's bottom-line.*	DSR participant	Capital setup costs to facilitate direct load control *Costs may be immaterial, particularly when this DLC is included in the functionality specification adopted for any general Ami roll out.* Operational costs associated with managing the customers' load *Costs not likely to be material relative to benefits, and maybe covered by the margin earned by the aggregator.*	DSR participant/DNSP DNSP/aggregator
Network capacity augmentation deferral including savings in the need to gain access to infrastructure corridors *Materiality will depend upon:* *i) the scale of controllable load at peak times;* *ii) the relative cost of augmentation; and* *iii) applicable service standards and incentives.*	DNSP		
Network reliability improvements including reduced interruption to CBD supply and any associated service incentive reward payments *Materiality as above.*	DNSP / CBD customers		
Retailers may also realise benefits via reduce peak energy sales to the extent that the retailers are not sufficiently hedged against peak energy prices. *Materiality will depend upon* *i) the scale of controllable load at peak times and the corresponding spot price at those times; and* *ii) the extent to which the retailer is already hedged against such peaks.*	Retailers	Lost sales revenue	Generators

6.2. Implications for rule development

The efficient provision and uptake of interruptible supply tariffs and associated DSR for a large-scale DSR project to relieve network constraints will depend upon:

§ DNSPs' ability to set efficient tariffs;

§ the extent to which the regulatory framework provides unbiased incentives for the costs associated with implementing such tariffs (and managing direct load control) and the equivalent network (capital expenditure) solution; and

§ the extent to which applicable service standards and incentives affect DNSPs' willingness to rely upon non-network solutions.

6.2.1. Regulatory or rule impediments

A number of aspects of the current and proposed initial distribution revenue and pricing rules may impede both of the above conditions including:

§ Tariff side constraints may prevent the DNSP from introducing financially rewarding interruptible supply tariffs in a timely manner (see Appendix A and section 7.8.1 of Part 1).

§ Differences in the treatment of expenditures to implement DSR tariffs compared to network augmentation expenditure (eg, as operating expenditure or capital expenditure, and variations in the efficiency benefit sharing arrangements for each), and the extent to which the regulated WACC reflects the DNSP's actual WACC (see section 4.2 of Part 1).

§ Application of deterministic planning standards rather than probabilistic planning standards may impede DNSPs' willingness and/or ability to rely on this form of non-network solution over which it has less direct control and for which the 'firmness' is uncertain, ie, relative to network solutions.

6.2.2. Implications

The implications of the above considerations and current regulatory impediments for rule development will be affected by the extent to which DNSPs have incentives and ability to:

§ provide efficient tariffs and tariff structures; and

§ give equal consideration to both network and non-network solutions to network constraints.

Thus the rules must:

§ motivate or require DNSPs to price efficiently;

§ require and allow DNSPs to price efficiently; and

- provide equal incentive for both expenditure and expenditure efficiencies on both network (capital expenditure) and non-network (predominantly operating expenditure) solutions to network constraints.

The recommendations proposed in our earlier report on network pricing can be expected to achieve the first requirement. However, equality in expenditure incentives warrants further consideration. In this regard, it is important to retain provisions for network support payments to be recognised in the building block approach, and that the method for capturing such payments does not bias DNSP decisions either in favour of or against them. The method must retain incentives for network support payments to be substituted for network augmentations when it is efficient to do so. To achieve this, we propose the following arrangements:

- In regulatory period one, DNSPs should not be provided an explicit allowance for network support payments (that have not already been contractually engaged). Rather, capital expenditure should be set so as to meet the network service provision needs, but with substitution by means of network support arrangements permitted to take place during the period. Any network support payments made during this period should be excluded from the application of any operating expenditure efficiency benefit sharing mechanism.

- In subsequent regulatory periods, those network support agreements already contracted should be included in the expenditure forecasts. At the ensuing regulatory reset, any difference between actual and forecast payments should then be adjusted for via an NPV neutral adjustment to the DNSP's regulatory asset base, ie, including timing compensation.

In sum, this approach is directed to removing any bias towards or away from network support payments by allowing initial negotiation of network support arrangements to be motivated by the extent to which they can efficiently substitute for network expenditure, and then including contracted network support in the building blocks in subsequent periods with adjustment for under- and over-recovery of associated costs.

Box 6.1
Rule Recommendations

- Provision in the Rules for the inclusion of payments made by DNSPs for 'network support' expenditure in the derivation of the building block revenue requirement should be retained.

- The method of recognising network support payments in the derivation of the building block revenue requirement should provide unbiased incentives for the efficient substitution of network support for network augmentation.

Box 6.2
Recommendations for consideration beyond the revenue and pricing Rules

- A review of the information requirements in Chapter 5 of the Rules is necessary to ensure that:
  - DNSPs provide DG proponents with the information necessary to apply the regulatory test o a DG connection proposal
  - DNSPS provide information on the emergence of network constraints as well as areas of substantial under-utilisation existing transfer capability in order to allow DGs to identify and site in the best location by reference to:
    - alleviating network constraints (and potentially earning network support payments); or
    - maximising energy transfer capability without incurring additional deep connection costs
  - DG proponents reveal their intended energy export levels such that DNSPs can accurately assess deep connection costs and formulate any connection constraint conditions that are required to protect network performance where:
    - the DG does not satisfy the regulatory test; and
    - the DG proponent chooses not the fund the deep connection costs..

6.2.3. Implications arising from the proposed national frameworks for electricity distribution network planning, network connection arrangements and connection charges

6.2.3.1. Implications arising from the proposed national framework for network planning

Under the proposed national framework for network planning, a mechanism will exist whereby projects such as a large CBD DSR project can be considered alongside both network and other non-network solutions to alleviate an emerging capacity constraint.

Information on emerging constraints will be made available through two channels:

- the annual planning report; and
- the detailed request for proposals (RFP) issued by a DNSP when the network solution would require an estimated capitalised expenditure of $2m or more.

These planning documents should lower barriers to entry for proponents such as a DSR aggregator by overcoming information asymmetries between the network operator and the rest of the market. The process will make available:

- sufficient information early enough in the planning process to identify where such a scheme could potentially alleviate a constraint and lead to the deferral of a network upgrade; and
- information on the value of a deferral (in terms of $ per kVa per annum) and therefore the funds available for non-network solutions.

A DNSP will face a requirement to evaluate all proposals it receives on an equal footing, using clear and transparent criteria, and to publish the results of its analysis. Where a DSR solution represents an efficient option this process should provide a mechanism for it to receive equal treatment with other network options. A mechanism will further exist for this analysis to be reviewed by an independent third party.

However, to justify the deferral of a proposed augmentation any large-scale DSR scheme would still need to satisfy the DNSP – to a reasonable standard – that it can deliver a 'firm' reduction in demand coinciding with the peak capacity load driving the constraint.

6.2.3.2. Implications arising from the proposed national framework for network connection arrangements

As in the case of the AMI case study, the ability to modify the connection agreement for issues such as demand side response without having to review all the other aspects of the connection agreement will simplify the process for large DSR projects.

6.2.3.3. Implications arising from the proposed national framework for connection charges

There are no obvious implications for large industrial users actively engaging in demand side markets arising from the proposed national framework for connection charges.

6.2.3.4. Implications arising from the proposed national framework for distribution loss factors

A customer's DSR will reduce the purchases that a retailer needs to make on its behalf, including the amount the retailer needs to purchase in respect of losses on the distribution system. However, reflecting practicality and administrative cost considerations, the losses that will be deemed to be avoided will reflect the average losses incurred in supplying energy to the area (rather than the losses avoided by reducing the last units of consumption) and will be a single, time-average loss factor for the year (rather than one that varies with the time of use of DSR).

As with PV, with retail competition the benefits that accrue to the retailer from the DSR activity should be passed on to the DSR proponent.

7. Large industrial user actively engaging in demand side markets

There are a number of ways in which large users can engage in demand management to reduce their demand for network capacity. The extent to which these affect their network capacity requirements will be driven by the ‘firmness’ of their demand reduction at times of system peak.

The large user may, for example:

§ engage with a DSR intermediary, such as Energy Response or Reserve, to participate in scheduled or on-call load curtailment or cycling;

§ allow its DNSP to exercise direct load control; or

§ install power factor correction equipment (though this is generally considered passive rather than active demand management).

7.1. Costs and benefits

It should be noted up front that the benefits arising under this case study will largely approximate those considered in chapter 4. The impact of the above active engagement in relation to the user’s connection service requirements will largely be determined by two factors:

1. the extent to which this engagement can guarantee reduced usage at peak times, ie, the ‘firmness’ of the demand management; and
2. the scale and timeliness of any reduction in the user’s bill.

As set out in chapter 3 of Part One, efficient charges for the provision of network services can be expected to be based on network capacity usage (at least to the extent that metering infrastructure permits this). This means that users actively implementing DSR would benefit from reducing capacity usage, but only to the extent that it is reduced in a sustained manner.

Where the user’s demand management can be demonstrated to be sufficiently ‘firm’, the DNSP should properly adjust (reduce) the user’s capacity charge, insofar as it relates to shared network assets. However the time horizon over which such firmness is established and the charge reduced may pose a barrier to the user’s willingness to engage in demand management.

From a DNSP’s perspective, it makes available a certain level of capacity to the user and will seek to recover the costs of having done so. For very large users, this may involve network assets that, while still part of the shared network, may substantially be needed to serve the demands of a small number of customers. In designing tariffs levels and structures for larges users so as to recover such costs, a DNSP needs to avoid the risk of having assets become ‘stranded’ if, to the extent they are no longer required by the particular user, which may not be sufficiently utilised by others so as to justify their continued inclusion as part of the shared network (and so the relevant costs being shared amongst all users).

While there are no explicit provisions in the Rules for the 'writing out' of such assets from the regulatory asset value, the point remains that when a user's demand requires a specific investment to be made, that investment generally is irreversible. Hence, if the user subsequently changes its maximum demand, it may be that few or any costs can be avoided, at least immediately. Economic principles would suggest that the user who caused the investment should continue to pay for it.

On the other hand, where demand is growing, and the relevant capacity is not highly specific to a single user, the reduction in capacity usage from one customer may quite quickly be taken up by another (and permit the next augmentation to be deferred). Thus, there is a point at which economic principles would suggest that it is efficient and appropriate to reassess the capacity caused or required by individual users.

In contrast to a DNSP's cost recovery motivations, a user who has reduced its capacity requirements may expect an immediate reduction in their bill, as is the case where they reduce their energy usage. A lag between the user's implementation of demand management and the receipt of financial benefits via reduced capacity charges will affect the user's pay-off period for demand management, and may increase the level of savings required to motivate demand management.

It follows that there may be a disconnect between the motivations of users and the cost recovery realities faced by DNSPs. Moreover, where distribution codes and pricing rules are ambiguous about the rules governing the review of capacity charges, and the assumed capacity usage requirements underpinning these), relationships between willing demand side market participants and their DNSPs may deteriorate, thereby reducing user's willingness to engage in such markets.

For reasons such as inherited historic tariff structures and/or the influence of side constraints, it is possible that unlike the situation described above, DNSPs may not be charging on the basis of a customer's capacity usage, and may instead be relying upon usage-based charges. Where this is the case, active user participation in DSR may affect the revenue sufficiency of the DNSP, particularly where the DNSP is regulated via a price cap (see section 7.4 of Part One). This will tend to motivate the DNSP to discourage such forms of demand side participation.

Table 7.1 Summary of benefits, costs and affected parties

Potential benefit ***Materiality***	**Benefit recipient**	**Potential costs** ***Materiality***	**Bearer of costs**
Preferential tariff i) Lower capacity charge ii) Lower usage charge *Materiality depends upon the amount of affected load and the value of network and/or retailer savings.*	DSR participant	Lower tariff revenue *Materiality depends upon the amount of interrupted load and the relative value of network savings.*	DNSP
Ability to ensure energy is only used when priced at levels that are cost effective for the customer via implementation of DSR at times of peak prices or via shifting of load from peak to off-peak consumption periods. *Materiality will depend upon energy cost contribution to customer's bottom-line.*	DSR participant	Capital or operating expenditure required to implement the DSR – eg: i) capital costs – cost of installing power factor correction infrastructure ii) operating costs – labour cost impact of shifting production to off-peak periods	DSR participant
Network capacity augmentation deferral *Materiality will depend upon:* *i) the scale of load reduction at peak times;* *ii) the relative cost of augmentation; and* iii) *applicable service standards and incentives.*	DNSP	Stranded assets or falling asset utilisation where there is insufficient demand growth from other customers to utilise the network capacity made available through the customer's active DSR. *Immaterial due to rules not permitting asset stranding or optimisation.*	DNSP
Network reliability improvements where DSR reduces capacity requirement of customer at coincident peak periods and any associated service incentive reward payments *Materiality as above*	DNSP / customers		
Retailers may also realise benefits by means of reduced peak energy sales to the extent that the retailers are not sufficiently hedged against peak energy prices.	Retailers	Lost sales revenue	Generators

7.2. Implications for rule development

7.2.1. Regulatory or rule impediments

The following regulations and rules are likely to act as impediments:

- Tariff side constraints that may prevent the DNSP from introducing a financially rewarding, yet viable, demand management tariff in a timely manner (see section 7.8.1 of Part One).

- Tariff reassignment constraints that may prevent the DNSP from reassigning customers to time of use tariffs without prior customer consent (see section 7.8.2.1 of Part One). Even where it may be possible to get this consent due to the financially rewarding nature of such a tariff, the requirement to gain consent adds to the administrative costs incurred in implementing these tariffs.

- Prescriptive rule definitions of what does and does not constitute network support can limit DNSPs' ability to make network support payments. Such definitions may limit the scope for DNSPs to make such payments and restrict innovation in the market for network support services. We note that this issue was raised by stakeholders in the AEMC's recent review of the transmission pricing and revenue rules. This resulted in a reduction in the level of prescription in the definition of network support between the draft and final rule determinations.

7.2.2. Recommendations

While the initial Rules include requirements for DNSPs to price efficiently, it is not clear that this also places requirements for capacity-based tariffs to be reviewed and revised in a timely manner. In fact, the only requirement for tariff review and adjustment is the annual tariff approval process which is to be assessed at a tariff class level.

It may therefore be appropriate for the rules to include a requirement for DNSPs to submit to the AER for approval their tariff reassignment and capacity charge review and adjustment procedures as regards individual customers and that these be published for customer reference.

Box 7.1
Rule Recommendations

- DNSPs should be required to submit to the AER for approval and publish protocols for the assessment and review of capacity demand and determination of capacity charges including:

  – the period over which capacity demand will be reassessed before capacity charges are reset (this should be limited to say 12 months).

7.2.3. Implications arising from the proposed national frameworks for electricity distribution network planning, network connection arrangements and connection charges

7.2.3.1. Implications arising from the proposed national framework for network planning

Under the proposed national framework for network planning, a mechanism will exist whereby financial incentives are available to large users to engage in demand side markets if by doing so they are likely to alleviate an emerging capacity constraint and defer the need for a network augmentation.

Information on emerging constraints will be made available through two channels

- the annual planning report; and
- the detailed request for proposals (RFP) issued by a DNSP when the network solution would require an estimated capitalised expenditure of $2m or more.

These planning documents should remove the information asymmetry between the network operator and the large user (or DSR aggregator) by making available:

- sufficient information early enough in the planning process to identify where such a scheme could potentially alleviate a constraint and lead to the deferral of a network upgrade; and
- information on the value of a deferral (in terms of $ per kVa per annum) and therefore the funds available for non-network solutions.

A DNSP will face a requirement to evaluate all proposals it receives on an equal footing, using clear and transparent criteria, and to publish the results of its analysis. Where a DSR solution represents an efficient option this process should provide a mechanism for it to receive equal treatment with other network options. A mechanism will further exist for this analysis to be reviewed by an independent third party.

However, to justify the deferral of a proposed augmentation any DSR scheme would still need to satisfy the DNSP – to a reasonable standard – that it can deliver a ‘firm’ reduction in demand coinciding with the peak capacity load driving the constraint.

7.2.3.2. Implications arising from the proposed national framework for network connection arrangements

The ability to modify the connection agreement for issues such as demand side arrangements without having to review all the other aspects of the connection agreement will simplify the process for large industrial users actively engaging in demand side markets.

7.2.3.3. Implications arising from the proposed national framework for connection charges

There are no obvious implications for large industrial users actively engaging in demand side markets arising from the proposed national framework for connection charges.

7.2.3.4. Implications arising from the proposed national framework for distribution loss factors

A large user's DSR will reduce the electricity purchases that it needs to make, including the amount that it (or its retailer) needs to purchase in respect of losses on the distribution system. However, reflecting practicality and administrative cost considerations, the losses that will be deemed to be avoided will reflect the average losses incurred in supplying energy to the area (rather than the losses avoided by reducing the last units of consumption) and will be a single, time-average loss factor for the year (rather than one that varies with the time of use of DSR).

Appendix A. Current and proposed side constraints

A significant constraint to efficient pricing of distribution services is the side constraints or 'tariff rebalancing constraints' applied in various jurisdictions and proposed for the initial rules. These limit the allowed annual movement in tariff class revenues or individual tariff component charges, and apply in addition to the applicable form of price control.

It is useful to note upfront that all consideration of distribution tariff side constraints (and their policy intents and practical outcomes) should be moderated by the understanding that the extent to which changes in distribution pricing affect customers will be determined by the extent to which retailers pass these price changes through to customers. This will in turn be affected by retailers' own commercial decisions regarding product differentiation and any applicable retail price caps.

The nature of distribution tariff side constraints (eg, expressed net or inclusive of consumer price inflation), the extent of their application (eg, to tariff components or to tariff classes) and the level of restrictiveness vary significantly across current jurisdictional arrangements. This variation is to be removed under the initial rules which propose a common constraint of:

- CPI+3.5% on each individual tariff component; as well as
- CPI+2% on the weighted average revenue from each tariff class.

This constraint may be viewed as more restrictive than the arrangements currently applied by the various jurisdictional regulators as shown in Table A.1. Current arrangements generally apply either one or the other of these forms of constraint, rather than both. Furthermore, even in those jurisdictions that currently apply specific nominal constraints to the fixed charge component of residential tariffs (ie, SA and NSW), the proposed constraint would be substantially more restrictive than existing arrangements (see Table A.2).

Note that for the avoidance of doubt, Appendix C of Part 1 provides an illustrative example of the tariff class terminology adopted in this discussion and the initial rule.

Table A.1
Current jurisdiction side constraints

Jurisdiction	Type of constraint	Level of constraint	Parameter constraint is applied to
NSW	real and	CPI+4.5%	Individual tariff components
	nominal	$30	Fixed residential tariff charges
Victoria	Real	CPI+2% (in addition to other annual price control formula adjustments for service incentive rewards/penalties and licence fee pass throughs)	Weighted average tariff class revenues
SA	real and	CPI+3.5%	Individual tariff components
	nominal	$5	Fixed residential tariff charges
Queensland	real	CPI+5%	Ergon's contestable customers' annual price movement
	real	CPI+4.5%	Energex's contestable customers' tariffs annual price movement
	No constraint is applied to franchise customers (including potentially contestable customer that have not elected to participate in the market)		
Tasmania	Constraints are currently applied at the (bundled) retail tariff level to the weighted revenue earned for a customer with the same consumption on each tariff. The constraints applied vary. For example, obsolete tariffs are permitted to increase by the annual increase inherent in the annual revenue requirement +6% whereas an additional constraint of no greater than CPI is applied to the fixed charge component of certain tariffs.		

Table A.2
Examples of fixed charge side constraint

	Fixed charge $/day	Fixed charge $/pa	Existing constraint $/pa	Proposed 3.5% constraint $/pa	Diff $	Diff %
SA - ETSA Utilities						
QRSR	0.235256	$85.87	$90.87	$88.87	$1.99	2%
MRSR	0.235256	$85.87	$90.87	$88.87	$1.99	2%
MRSRI	0.235256	$85.87	$90.87	$88.87	$1.99	2%
QRSROPCL	0.235256	$85.87	$90.87	$88.87	$1.99	2%
MBSROPCL - controlled load type 5 or 6 meter	0.235256	$85.87	$90.87	$88.87	$1.99	2%
MBSROPCL - controlled load type 1-4 meter	0.235256	$85.87	$90.87	$88.87	$1.99	2%
QOPCL	No applicable standing charge					
MOPCL - controlled load type 5 or 6 meter	No applicable standing charge					
MOPCL - controlled load type 1-4 meter	No applicable standing charge					
NSW - Integral						
Domestic (IBT)	0.20	$73.00	$103.00	$75.56	$27.45	38%
Controlled load (OP 1)	0.02	$7.30	$37.30	$7.56	$29.74	407%
Controlled load (OP 2)	0.02	$7.30	$37.30	$7.56	$29.74	407%
Domestic TOU - type 5 meter	0.47	$171.55	$201.55	$177.55	$24.00	14%
Domestic TOU - type 5 meter	0.21	$76.65	$106.65	$79.33	$27.32	36%
Domestic (IBT) + controlled load 1	0.22	$80.30	$110.30	$83.11	$27.19	34%
Domestic (IBT) + controlled load 2	0.22	$80.30	$110.30	$83.11	$27.19	34%

A.1. Parameter for Side Constraint Application

In addition to the actual rate of constraint (eg, 2%, 5%, etc), the tariff parameter to which side constraints are applied will affect the level of efficient tariff rebalancing that a DNSP can undertake. In this way, the parameter should be carefully chosen to reflect the intent of the side constraint.

As identified in Table A.2, currently different parameters are used in different jurisdictions. There are broadly three parameter approaches available.

1. weighted average tariff class revenues;

2. individual tariff components; and

3. average customer bill.

A.1.1. Weighted average tariff class revenues

This approach is more or less applied in the same way as price cap. However instead of being applied to the weighted revenues of all of a DNSP's tariff classes, it is applied separately to revenues from each individual tariff class. To illustrate this similarity, below are the distribution price control and distribution tariff side constraint formulae currently applied in Victoria.[19] The difference can be seen to be the absence of an additional summation sign that, under the price cap, aggregates the weighted average revenues of all tariff classes.

Price cap[20]

$$(1+CPI_t)(1-X_t)L_tS_t \geq \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} q_{t-2}^{ij}}$$

2% real side constraint[21]

$$(1+CPI_t)(1-X)(1+0.02)L_tS_t \geq \frac{\sum_{j=1}^{m} p_t^{j} q_{t-2}^{j}}{\sum_{j=1}^{m} p_{t-1}^{j} q_{t-2}^{j}}$$

Where:

- p_{t-1}^{ij} is the tariff component charge being charged in the year $t-1$ for component j of tariff class i;
- p_t^{ij} is the proposed tariff component charge for component j of tariff class i in year t; and
- q_{t-2}^{ij} is the quantity of component j of tariff class i that was sold in the year $t-2$.

Applying the side constraint to this parameter achieves the effect of constraining the growth in the revenues a DNSP can earn from a given group of customers (or single customer where the tariff class applies to only one customer).

---

19 Note that this is the specific side constraint applied for the movement between regulatory periods. The x-factor is not included in the side constraint applied within the regulatory period.

20 See clause 2.3.2 ESC (October 2005), Electricity Distribution Price Review 2006-10, Final Decision Volume 2 Price Determination.

21 See clause 2.4.2 ESC (October 2005), Electricity Distribution Price Review 2006-10, Final Decision Volume 2 Price Determination. Note that additional factors are also included in the side constraint to accommodate additional annual tariff movement arising from the service incentive scheme (S factor) and licence fee pass though (L factor).

A.1.2. Individual tariff components

This approach limits annual changes in the tariff applied to any given charging parameter. That is, it is applied separately to each: fixed, peak usage, off-peak usage and capacity charges. A formulaic representation of such a constraint is provided below.

$$(1+CPI_t)(1+0.035) \geq \frac{p_t^j}{p_{t-1}^j}$$

Where:

- p_{t-1}^j is the tariff component charge being charged in the year $t-1$ for component j; and
- p_t^j is the proposed tariff component charge for component j in year t;

Applied alone (ie without the overarching weighted average tariff revenue constraint proposed in the initial rules), application of a constraint to individual tariff components may have the aggregate effect of allowing greater customer impact than is achieved under a revenue based constraint. For example, SA applies a 3.5% constraint to all components. Consider now a situation where the DNSP raises all component charges by this amount. The resulting revenue impact would 3.5%.

Notably, this 3.5% outcome is greater than the 2% impact achieved under the 2% revenue based constraint applied in Victoria. However masked in this difference is the fact that DNSPs regulated under a revenue based constraint would have substantially more flexibility to rebalance individual tariff component charges in order to ensure these efficiently reflect the usage costs of different forms of consumption (be they related to time of energy use, capacity, or connection). In this regard, a revenue based constraint can be expected to afford DNSPs greater flexibility to adjust to new charging parameters made possible by AMI (than would a component approach) while still smoothing the transitional impact on customers.

A.1.3. Average customer bill

This approach is used in some jurisdiction for the application of pricing constraints on retail tariffs. Under this approach the annual movement in the revenues earned from a given tariff class are assessed by reference to the estimated annual demand of an average customer who is assigned to that tariff class.

This approach is similar in many ways to the weighted average tariff class revenues approach considered above save that:

- the weights are estimated weights for a single customer; and
- the allowed annual revenue movement is assessed per customer rather than collectively for all customers assigned to that tariff class.

This is illustrated by the following formula.

$$(1+CPI_t)(1+0.05) \geq \frac{\sum_{j=1}^{m} p_t^j q_{est}^j}{\sum_{j=1}^{m} p_{t-1}^j q_{est}^j}$$

Where:

- p_{t-1}^{ij} is the tariff component charge being charged in the year $t-1$ for component j of tariff class i;
- p_t^{ij} is the proposed tariff component charge for component j of tariff class i in year t; and
- q_{est}^{ij} is the quantity of component j of tariff class i that is estimated to be sold to an average customer on tariff class i in the coming year (ie, year t).

The estimation process required to give effect to this approach may introduce scope for greater manipulation of allowed pricing movement outcomes than is the case under the weighted average revenues approach where the weights are determined by audited historic tariff quantities. Issues associated with the choice of tariff weighting for price control and side constraint formulae are examined in more detail in section 6.4.1 of the NERA Distribution Pricing Rule Framework report.

NERA
Economic Consulting

NERA Economic Consulting
Darling Park Tower 3
201 Sussex Street
Sydney NSW 2000
Tel: +61 2 8864 6500
Fax: +61 2 8864 6549
www.nera.com

NERA Australia Pty Ltd, ABN 34 092 959 665

MMC Marsh & McLennan Companies