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Directions Paper on Economic Regulation of Network Service Providers

The Energy Supply Association of Australia (esaa) welcomes the opportunity to make a submission to the AEMC on its Directions Paper on Economic Regulation of Network Service Providers.

The esaa is the peak industry body for the stationary energy sector in Australia and represents the policy positions of the Chief Executives of 38 electricity and downstream natural gas businesses. These businesses own and operate some $120 billion in assets, employ more than 61,000 people and contribute $19.3 billion directly to the nation's Gross Domestic Product.

The rule changes proposals under consideration are undoubtedly driven by concerns over the rising costs of network services. Some of these costs are cyclical, such as the replacement of aging infrastructure, while others, such as rising peak demand will simply continue unless steps are taken to actively reduce them. One way to do this is to institute policy reform and enabling technology to both empower consumers and incentivise them to shift load away from the peaks. Better capital utilisation of the network has the potential to significantly mitigate network unit cost rises. However, this will require changes such as the following:

- introduction of digital ("smart") meters;
- tariff reform and retail price deregulation to allow flexible and innovative tariff structures that provide appropriate price signals to end users;
- advanced network communications infrastructure – not only to provide an interface with new meters, but also to facilitate management of the network in a way which allows for greater utilisation without compromising reliability; and
- enabling of direct control of specific loads suitable either for time-shifting (e.g. pool pumps) or cycling on/off without loss of amenity (e.g. air conditioners, refrigeration)

Other changes may be driven by consumer choices themselves, including electric vehicles and distributed generation. These have the potential to either exacerbate capital utilisation issues or to mitigate them, depending on the policy settings.

These changes will require network service providers (NSPs) to invest in new technology and to innovate in the way they operate their networks and engage with customers. Maintaining a regulatory framework that appropriately encourages investment and in particular innovative approaches to network operation where the benefits can be expected to outweigh the cost, will be important. This will need to be coupled with a regulatory approach that recognises the value of enabling tariff reform and protocols for direct load control. By contrast, a regulatory approach that focuses purely on driving allowed revenues lower in the short term is unlikely to result in the right incentives for NSPs to explore these opportunities.

These themes are explored further in two attachments to this submission. Attachment 1: *Electricity network innovation and the regulatory framework* expands on the arguments above to explain why the right economic regulatory framework for NSPs is a key component of the policy settings that will enable these opportunities to be realised. Attachment 2: *Analysis of initiatives to lower peak demand* is a report prepared by Deloitte for the esaa that estimates the potential financial gains from five initiatives to reduce peak demand, based on a synthesis of existing analysis.

The focus of these papers is on electricity distribution networks, which reflects both the particular initiatives discussed and the fact that the rule changes are largely aimed at these NSPs. However the general point that innovation by energy networks can provide valuable benefits that customers ultimately share in and that the economic regulatory framework should be designed to support such innovation applies equally to transmission and to gas networks.

Any questions about our submission should be addressed to Kieran Donoghue, by email to kieran.donoghue@esaa.com.au or by telephone on (03) 9205 3116.

Yours sincerely

Matthew Warren
Chief Executive Officer

Attachment 1: Electricity network innovation and the regulatory framework

Executive summary

This paper explores the interaction between regulatory arrangements for energy networks and innovation in the industry with a particular focus on electricity distribution network service providers (DNSPs). It notes that a suite of current and developing technologies, collectively termed the "future grid", provide an opportunity – or the requirement - over the ensuing decade for significant change in the way DNSPs operate and how consumers engage with the electricity system. Achieving this change as smoothly as possible will be very challenging.

It will entail innovative approaches from DNSPs that will require them to carry out research and development activity, to trial novel approaches and to engage with customers more than previously, whether directly or via retailers. Inevitably with new technologies and new approaches, there will be some initiatives and trials that do not pay off. Accordingly, the risk profile of the activity of building and operating a distribution network will likely rise during this period of change.

There are substantial benefits that can be obtained from widespread adoption of new technologies and tools for managing electricity use. Enumerating and valuing them all is a huge exercise, beyond the scope of this paper. One of the key benefits that impacts the costs of a DNSP is the opportunity to reduce demand at the peak. Peak demand has been rising faster than consumption for several years and is expected to continue to do so for the foreseeable future. Energy networks must build their infrastructure for peak demand in order to meet reliability standards and targets. Since network charges are largely on consumption, the trend towards lower capital utilisation is an important driver of increased electricity prices.

It follows that reducing peak demand, especially relative to consumption, can have significant price benefits. The esaa commissioned a report from Deloitte (Attachment 2) that seeks to estimate the potential benefit from a range of quantifiable initiatives in terms of reducing peak demand. Many of these initiatives will also deliver other benefits, which were not quantified in the report. Deloitte estimated that a gain of $1.6-$4.6 billion in savings could be achievable in the decade to 2022. For residential customers, this would equate to a saving of around $4-15/MWh in 2022. Given that the capital avoided has a useful economic of life of typically 40 years or more, these benefits could be sustained for many years beyond the period covered in the report.

For these benefits to be realised, the right policy and regulatory settings must be in place. A full consideration of these is beyond the scope of this paper; however, a key element is having the right framework for economic regulation of DNSPs. The current round of rule change proposals being considered by the AEMC aim to systematically restrict both the expenditure and the return on capital of the DNSPs. These proposals will serve to discourage DNSPs from uncovering innovative solutions to the challenges of the energy future.

The Productivity Commission has only just embarked on its review of NSPs (including transmission networks) and benchmarking. However, it is critical that the potential changes discussed in this paper are fully taken into account within this project. Different DNSPs may find that their move towards this future proceeds at different rates, driven by different rates of consumer take-up or different state and territory government policies. For example, take-up of PV panels and the consequent impact on DNSPs will vary both with weather patterns (PV will be a better prospect in Queensland than in Tasmania, for example) and government policies on subsidies for PV, which have varied widely between jurisdictions. Inappropriate use of benchmarking, particularly as these differences emerge and impact DNSPs' cost structures, could also have a stifling effect on progress in the sector.

The background to the current arrangements

The national regulatory framework for energy networks was created in response to various key reviews of the stationary energy sector that highlighted the benefits that could be obtained by moving from the existing patchwork of state-based regulation to a consistent, national framework. For example, the MCE's Reform of Energy Markets report argued that Australian governments should "streamline and improve the quality of economic regulation across energy markets, to lower the cost and complexity of regulation facing investors, enhance regulatory certainty and lower barriers to competition"[1]. During this period of reform, the advantages of light-handed regulation were recognised[2], along with the importance of creating a regime that would encourage the investment the sector needed.

The MCE commissioned an Expert panel on Energy Access Pricing and their final report in 2006 was influential in the design of the regulatory framework. Notably, one of the panel members submitted a dissenting commentary on the framework for regulatory decision making, arguing for less regulatory discretion to be embedded in the framework than his panel colleagues recommended. The rationale given was based on a greater weight being put on the inefficiencies and distortions of regulation. As an example of this, he cited the stifling effect of regulation in the gas industry on innovation (R&D):

"a decreasing willingness for the industry as a whole to invest in R&D - the cessation of R&D could be partly reflective of a perverse outcome from the R&D undertaken by the industry in the early 1990's which reduced the replacement cost of gas pipeline infrastructure, and in turn, exerted a downward influence on regulated prices once gas pipelines became subject to regulation".[3]

The transfer of economic regulatory responsibilities from states and territories to the AER has taken place progressively, with the final round of initial price control reviews taking place currently (Aurora is the final DNSP to have a price control set by the AER). This has coincided with a range of upward cost pressures that have contributed to significant cost rises for end consumers.

Recent cost drivers

The recent cost drivers are two-fold: requirements for increased capital expenditure and a rise in the cost of capital. The first of these is a result of a concurrent combination of factors: the need to replace ageing infrastructure (see figure 1 below); the need to meet peak demand requirements (see figure 2 below); the need to service population growth; and in some jurisdictions the requirement to meet more stringent reliability planning standards. The strength of these factors varies between DNSPs, but it is difficult to separate the impact of

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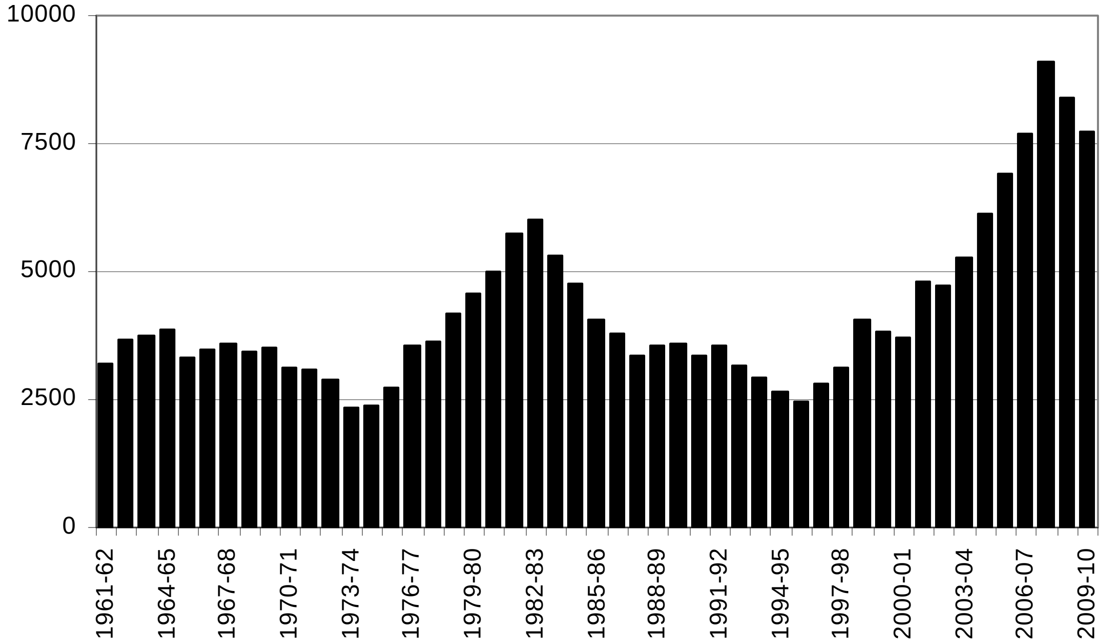
1 MCE report to COAG, Reform of Energy Markets, 2003

2 The Productivity Commission's Gas Access review of 2003, for example, contained a detailed chapter on the advantages of light-handed regulation

3 Euan Morton, *Dissenting commentary on chapter 5, Expert panel on Energy Access Pricing (Final report to the MCE)*, April 2006, p4

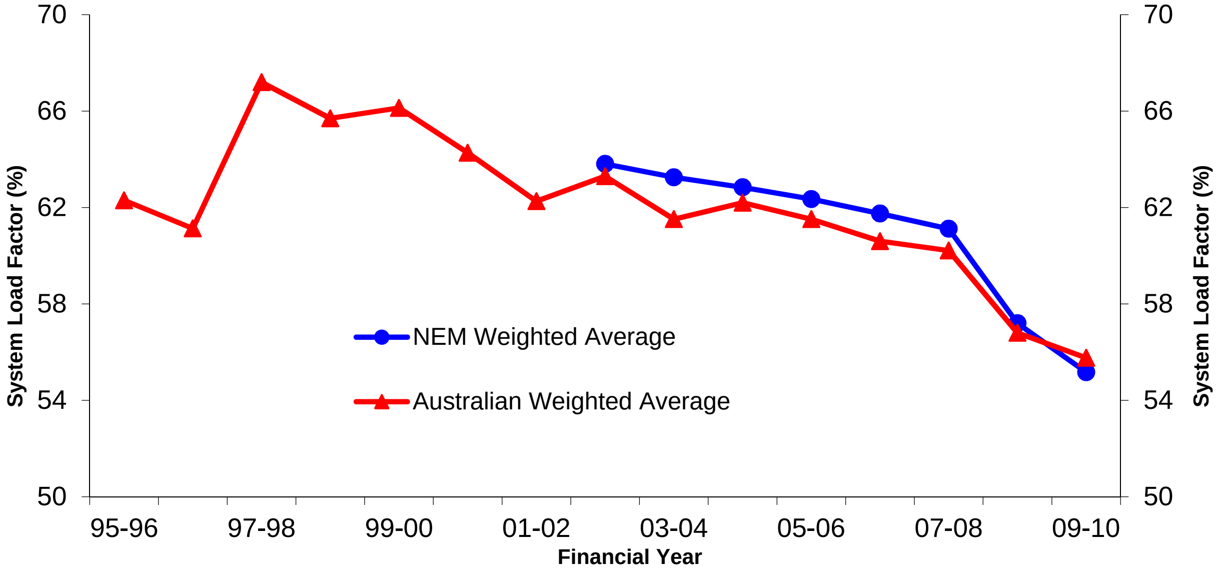
each of them out. Decisions about the most efficient timing of replacement will be affected by the stresses on the network and whether an upgrade is required regardless of replacement. Peak demand projections will be further exacerbated by population growth and may lead to the need for upgrades or for larger greenfield projects than otherwise. The cost of meeting increased reliability planning standards will be higher if the DNSP has to build to meet higher peaks.

Figure 1 – Electricity supply: Real capital investment, 1961-62 to 2009-10 ($ million, constant 2006-07 dollars)[4]



[4] Productivity Commission staff working paper *Productivity in Electricity, Gas and Water: Measurement and Interpretation*, Vernon Topp and Tony Kulys, April 2012, p62

Figure 2 - System load factor Australia and NEM regions, 1995-96 to 2009-10[5]



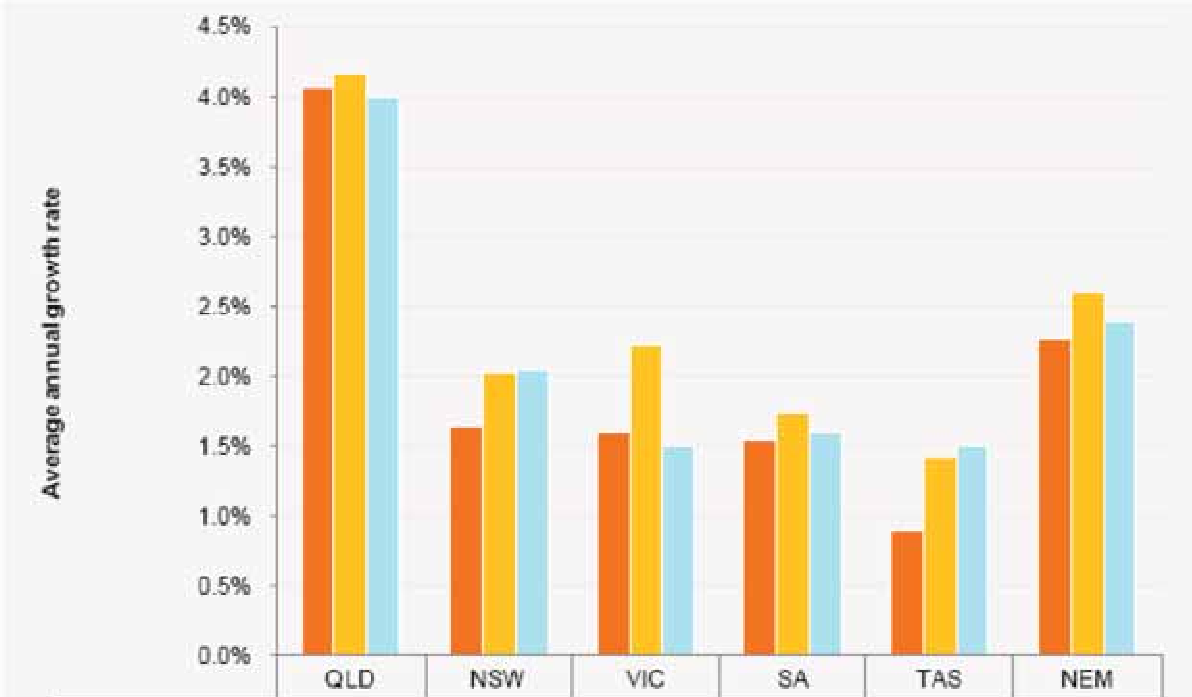
The general trend of these factors affecting capital expenditure is clear from a number of independent reviews. The Productivity Commission recently published a review of productivity in the Electricity Gas, Waste and Water industries. Their analysis of the electricity industry identified the cyclical nature of asset expenditure in the industry and the decreasing capital utilisation of the system.

They also noted that the conventional productivity measurement did not capture improvements in the quality or amenity of the service. In this respect they noted the increasing trends for undergrounding of distribution cables, in line with the community's preferences. Naturally this approach is more costly.

Looking to the future, while the asset cycle will in time turn down and reliability standards are not expected to increase further, capital utilisation is forecast to deteriorate further. Figure 3 shows AEMO's forecasts as per the 2011 Electricity Statement of Opportunities.

[5] Source: *Electricity Gas Australia* (various years), esaa

Figure 3 AEMO estimate of annual maximum demand growth and energy growth to 2020-21[6]



	QLD	NSW	VIC	SA	TAS	NEM
Energy (GWh)	4.1%	1.6%	1.6%	1.5%	0.9%	2.3%
Summer MD (MW)	4.2%	2.0%	2.2%	1.7%	1.4%	2.6%
Winter MD (MW)	4.0%	2.0%	1.5%	1.6%	1.5%	2.4%

This is therefore an area that it is important to address in order to mitigate cost pressures on the industry.

The cost of capital

The years running up to 2008 were characterised by the availability of very cheap capital. This led to debt being widely available at low costs even at high levels of gearing. This was recognised in jurisdictional price control decisions that referenced benchmark debt costs, and consumers benefited from the low capital costs.

However, the global financial crisis led to a re-rating of risk by lenders. The availability of credit was greatly reduced and the costs increased. This occurred at the time that the AER was measuring debt risk premia for its first round of price controls. These increases fed into revenue determinations, in accordance with the Rules.

The combination of higher levels of investment and higher costs of capital than in the previous price controls led inevitably to upward pressure on network prices. Even so, the impact varied across jurisdictions. On the one hand, Queensland and NSW networks typically saw large increases. However, the networks in both these states had been through a period of very low investment during the 2000s and so there was a consequent requirement to catch-up for that lack of investment. This was bolstered by more stringent reliability planning requirements following customer dissatisfaction with service interruptions due to the period of low investment.

[6] AEMO Electricity statement of opportunities 2011, executive briefing, p16.

By contrast networks in Victoria did not require such a large increase for their ongoing network expenditure. The DNSPs there had been privatised some years previously and so had been subject to arms' length regulation for a longer period that arguably fostered a more stable investment environment. However, the Victorian government mandated an accelerated replacement of existing meter stock with Advanced Metering Infrastructure (AMI) that was largely concurrent with the AER's first price control. This has been a significant driver of increased electricity prices in Victoria.

The opportunities and challenges that arise from innovation

Technologies that are essentially available today but that are not yet widely deployed in Australian distribution networks or by their customers provide a range of opportunities for all parties (NSPs, retailers, generators, energy service providers and consumers). They include opportunities to mitigate the rising cost of running networks, to improve capital utilisation by arresting the rise in peak demand; to empower consumers by giving them richer information about their energy use and the attendant costs; giving them the opportunity to generate, store and export electricity; giving DNSPs better information about the performance of the grid and the stresses it is subject to; and improving the quality of electricity supply by minimizing outages and voltage fluctuations.

Smart grids

Some of these opportunities are straightforwardly within the purview of the DNSP. These are typically grouped under the term "smart grid" and broadly can be considered as the digitisation of the network. This can include various forms of distribution automation, which includes volt/VAR control, fault location, isolation and service restoration. It can also include AMI ("smart meters"). A common theme through the various smart grid applications is enhanced information and communication technology.

Advanced distribution automation schemes can deliver a number of benefits to the network, for example:

- They can allow substation relays to detect many high-impedance faults that cannot be detected with conventional distribution protection.
- Feeder reconfiguration enhances reliability by sectionalizing the smallest portion of the system when a fault occurs and maintaining service elsewhere. Automatic network reconfiguration allows the grid to "self-heal," keeping the lights on for most consumers and rerouting power automatically around a faulted area. Using synchrophasor measurement throughout a system, even at the distribution level, helps identify instability quickly, so corrective actions can be made. Additionally, new fault location technology quickly guides crews to the precise fault point, so repairs can be made and service restored.
- They can monitor and determine the type of load on the system so that conservation voltage recovery can be implemented at times and in locations where it will be most effective. This will become more important with new stresses on the system like electric vehicles and distributed generation (DG).

Aside from the potential future cost savings, distribution automation recently carried out by Southern California Edison in the US led to a demonstrated reduction of 33 min (47%) to average Customer Minutes of Interruption (CMI) and 17% reduction of total CMI per circuit[7].

Smart meters are a necessary component of the system for implementing dynamic pricing (see below). The national review of smart meters carried out by NERA for the Ministerial Council on Energy estimated that nationally, the net benefits of smart meters could be as high as $3.7bn if a home area network interface was included in the rollout[8]. Although the potential net benefits of demand response arising from dynamic pricing were substantial, the majority of the net benefits came from business efficiencies and other benefits, such as: the lower cost of routine and special meter reading; the avoided costs of manual disconnections and reconnections; reductions in calls to faults and emergency lines; and avoided costs of customer complaints about voltage quality of supply. There were also expected to be some benefits over time for retailers, including lower bad debt costs, a reduction in call centre costs re billing enquiries and savings from improved settlement processes.

Dynamic pricing

Currently many customers including most residential customers do not face appropriate price signals relating to their demand at peak times. If they did, they would have an incentive to shift loads or to be more energy efficient with their use at peak times.

Dynamic pricing can take several forms. The most straightforward is a 2 or 3 part peak/(shoulder)/off-peak pricing structure (time of use or TOU) for predetermined periods in each week. The data necessary to bill on this basis can be captured using an interval accumulation meter and so does not require AMI.

However, the absolute peaks on each part of the system are typically only a few days each year. Energex estimates that 11% of its network investment is to meet a level of peak demand that only occurs 3 days of the year. Parts of Victoria and South Australia are peakier still. AMI enables pricing structures such as critical peak pricing (CPP) and critical peak rebates (CPR). These apply on a pre-determined number of days each year. Since the peak days depend on extreme weather conditions, forecasts are used to notify customers shortly before each day that it is a critical peak day. Under CPP a high price is levied for consumption that day. Under CPR, pricing is at normal (peak) levels, but customers can gain a reward for reducing their demand below expected levels. Psychologically the latter approach is often preferred by customers even though total electricity bills over the year will not necessarily be any less.

While these are the most widespread forms of dynamic pricing, other approaches are possible. As the Victorian experience has shown, however, the introduction of dynamic pricing can rise community concerns (although voluntary trials, such as some of those carried out by NSW distribution businesses have typically elicited a more positive response). This is an area where DNSPs and retailers will likely have to proceed carefully. Customer education and engagement will be critical and may require some form of bill protection if

[7] *Realizing the value of an optimised grid*, Gridwise Alliance, February 2012, p5

[8] NERA, Cost benefit analysis of smart metering and direct load control, May, 2008, p9

consumers prove particularly sceptical. Funding such bill protection will however be an issue.

Demand response and direct load control

One way to elicit demand response is via tariff structures, as discussed above. But this is only one of many ways that demand response may be procured. This area is of course already under review by the AEMC through its *Power of Choice* review. While it is important to confirm that the National Electricity Rules do not inhibit cost-effective demand-side management, other developments will be required to capitalise on the opportunities offered by current technology.

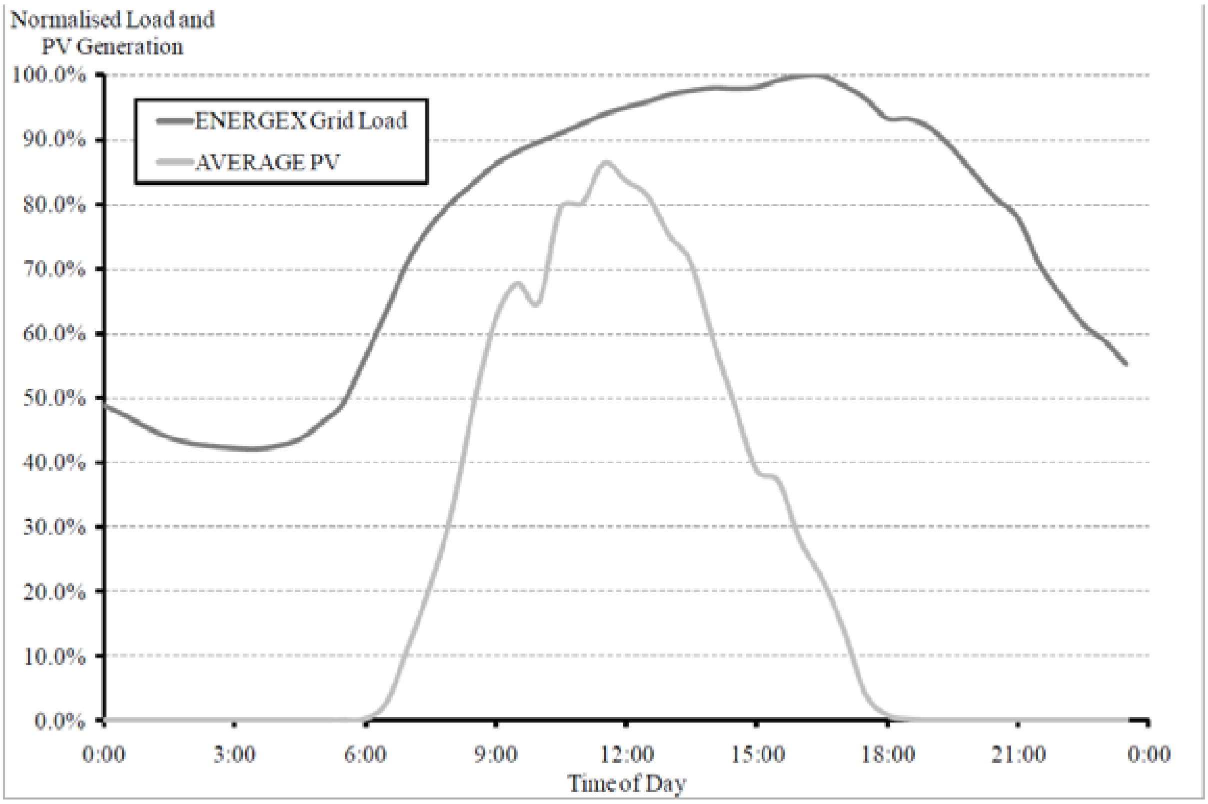
For example, direct load control (DLC) offers the possibility for DNSPs to manage periods of peak demand by shifting non-time dependent loads (such as pool pumps) to off-peak periods and by cycling time-dependent loads (such as air-conditioning). While DLC could be a tool used by other parties, it is likely to be a more effective tool for avoiding capital expenditure if the DNSP has clear visibility and certainty of its use. However, the right communications architecture has to be in place as well as having the functionality embedded (or retrofitted where feasible) into the relevant appliances.

Distributed generation and storage

A particular form of demand response is where consumers invest in their own generation and/or storage. Typically they will want to be able to export surplus power (especially if they do not have storage capabilities). The most common form of distributed generation is rooftop solar photovoltaic panels (PV). PV generation, especially in a localised area such as a residential feeder, tends to be coincident. It is of course also intermittent. Accordingly, higher levels of penetration can cause voltage fluctuations. At around 25 per cent penetration, these risk becoming uncontrollable. The issue may be even more acute on long rural feeders.

Supporters of PV argue that it reduces peak demand and thus provides benefits to the network. However, residential areas in particular often experience their peak demand in the evening when PV can contribute little. An example from Energex's network is shown below:

Figure 4: Solar PV output vs. day of peak demand in SE QLD (15 Feb 2010)[9]



Other forms of distributed generation may also place new stresses on DNSPs. Strengthening the grid to be resilient to two-way flows of energy is a relatively new requirement. Fortunately investing in some of the smart grid technologies described above can help. However, it is a tall order for a DNSP to forecast the efficient level of expenditure in this regards when they do not have control over the take-up of distributed generation. Changes in both federal and state and territory government policies for subsiding small-scale PV have in recent years driven a rapid boom in PV installation followed by a strong deceleration as the policies were scaled back or withdrawn at short notice. Planning for such policy changes is challenging.

Electric vehicles (EVs)

Penetration of EVs is low in Australia. Most major car manufacturers have at least one model of electric vehicle on the market, however, and there are some niche businesses that specialise in conversions from existing models. From an electricity system perspective, there are two types of EV to consider: Battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) as these have the capability to charge direct from the electricity system. So-called hybrid EVs do not and as such are not a relevant consideration.

From DNSPs' perspective, the impact of EVs will primarily be where, when and how quickly EVs are charged. The AEMC's Review of Energy Market Arrangements for Electric and Natural Gas Vehicles considered some of the main issues that could arise from increasing

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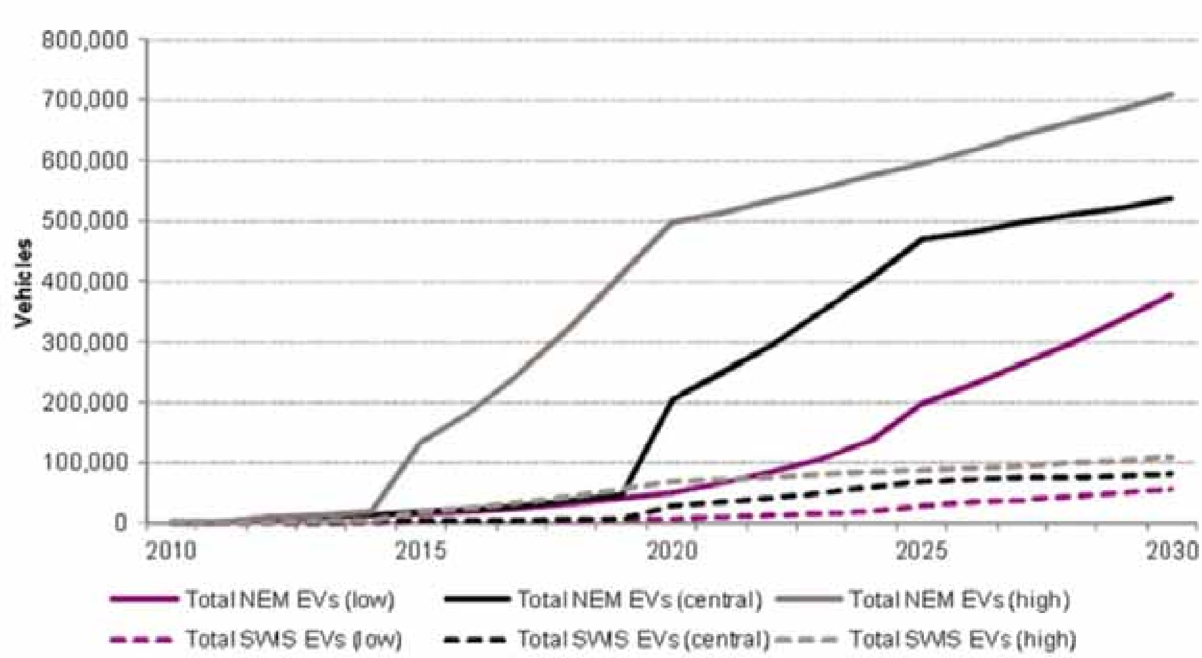
[9] Source: Energex, Evans & Peck, reproduced in AGL working Paper no. 25, *Australian residential solar Feed-in Tariffs: Industry stimulus or regressive form of taxation?* March 2011, p14

penetration of EVs. Figure 5 below shoes the potential penetration of EVs in the Australian market as modelled by AECOM:

Figure 5: estimated annual sales of EVs in the NEM and the SWIS[10]



What can be seen is the uncertainty of the timing and rate of uptake of EVs. Depending on market conditions for EVs, the high case suggests rapid take-off as early as 2015, while in the low case a similar level of annual sales is not reached until almost a decade later. The impact of rapid take-off on particular areas of the network will be exacerbated by the likelihood of “spatial clustering” of EV owners. If uncontrolled charging is allowed without price signals, AECOM estimate that under their central scenario, peak demand will be increased by over 7 per cent in 2020.[11] By contrast, if charging is either controlled or subject to price signals this can be avoided, But this will require investment in appropriate metering o DLC technology.

Projecting further into the future, vehicle to home or vehicle to grid (V2G) discharging of the battery offers the possibility of EVs actually providing grid support. But optimising such capabilities will require investment, not just in communications and metering infrastructure, but also in understanding how to integrate such a power source most effectively into the grid.

Overall benefits of reducing peak load

Measures to curtail or shift peak load have great potential value in terms of reducing growth-related infrastructure spending and, therefore, constraining rises in electricity prices.

The esaa engaged Deloitte to undertake analysis of the potential benefits from initiatives to lower peak demand in Australia, based on high level estimates of the value of avoiding peak demand and publicly available results from trials and studies. Their report (Attachment 2)

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[10] Source: AECOM, reproduced in AEMC, *Energy Market Arrangements for Electric and Natural Gas Vehicles Issue Paper* , January 2012, p12

[11] Ibid. p32

presents the results of our analysis of the high level benefits of implementing selected Initiatives to lower peak demand. The initiatives include several discussed above plus the impact of building efficiency measures that can impact peak demand:

Table 1: Total estimated value of gross benefits, 2012-2022 (NPV $m)[12]

Initiative	Low case benefits ($m)	High case benefits ($m)
Time of use pricing	57.8	192.7
Critical peak pricing and incentives	385.4	1,271.8
Direct load control of air conditioners	200.0	1,338.4
Direct load control of pool pumps	188.0	230.8
Electric vehicles	59.7	537.2
Energy Savings Measures	360.6	486.3
Enhanced uptake of Solar PV	299.7	527.9
Total gross benefits	**1,551.3**	**4,585.2**

Details on the potential costs to achieve are also presented for each modelled initiative. It is not appropriate to compare the costs and the benefits, given the wide array of other benefits that each initiative brings that are not quantified. The analysis is a synthesis of publicly available trial results and models, based primarily on Australian data, to which Deloitte have applied their own expert judgement.

The report concludes that the economic value of the combined potential gross benefits due to peak demand reductions delivered by the six initiatives studied ranges between $1.5 and $4.6 billion, over 2012-13 to 2021-22. The estimated total demand savings from these initiatives ranges between 2,382 and 7,410 MW. These results do not represent the maximum achievable benefit from peak demand reduction, but Deloitte consider these to be a plausible range of outcomes based on a conservative set of assumptions and the evidence they reviewed.

Additional challenges to the business

Compared to the incremental changes in operational practices and network technology of recent decades, this suite of innovations represents a profound change in the way that DNSPs work. It is not simply a matter of understanding the new technology. One area of significant change that the DNSPs will have to manage is what the impact on their workforce will be. As a utility deploys smart grid technologies and systems, a variety of workforce challenges will be encountered, including managing an increasingly complex infrastructure, replenishing an aging workforce, and leveraging an increasing amount of field data, all while

[12] Source: Deloitte analysis, see attachment 2 for further details

continuing to operate a safe, secure and reliable network. Introducing smart grid technologies requires employees with different skills to support the implementation, maintenance and operation of the systems. Accomplishing this, in an environment where it is already difficult to get highly skilled employees with technical experience, will be challenging.

What Australian DNSPs are currently doing

Australian DNSPs are already actively trialling many of the new technologies and are engaging with consumers on demand side changes. The flagship project is Ausgrid's Smart Grid Smart City project, which has secured funding from the federal government. The funding is being suited to deploy a live, integrated, commercial size smart grid in the Newcastle area, with parts of the trial being carried out elsewhere in Ausgrid's network.

Several DNSPs are involved with the Solar City consortia spread across Australia. DNSPs are engaged in EV trial projects (ActewAGL have partnered with EV charging provider Better place for the initial roll-out of their charging infrastructure in Canberra). Direct load control is being trialled by a number of networks.

However, moving from trials and pilots to full-scale rollouts is a big step – the only example of the latter is the mandatory rollout of AMI in Victoria. To some extent, a government mandated technology upgrade is a more straightforward prospect for the DNSP to evaluate the cost of the program and for the regulator to satisfy itself that the cost proposal is efficient. For various reasons, the AMI program in Victoria has not been well received by the community. This may make it less likely that AMI will be mandated by other jurisdictions and so the penetration of AMI in those jurisdictions will need to be driven differently. For example, IPART has recently argued that any roll-out in NSW will need to be on a voluntary basis (regardless of whether this would actually be the most cost-effective way to do so)[13]. This will add to the complexity of rolling out smart meters and make it harder to determine both the costs and the timing of such a program *ex ante*.

Why the AER's proposed rule changes undermine the opportunities smart grids offer

AER proposal to have more discretion in setting capex/opex

The novelty of many of the technologies discussed above will make forecasting the appropriate amount of expenditure challenging, even for the DNSPs. It has always been the case that it is not realistic to consider that there is a "correct" level of expenditure that can be determined *ex ante* but it is even more so with smart grid investments and responding to the impact of new consumer behaviours. The DNSPs will be the ones working on a daily basis in this changing environment and will clearly have the best insight. The AER often engages engineering consultants to assess DNSPs' forecasts and to provide an alternative view. This approach can be problematic even for considering conventional investment decisions, since it boils down to setting one engineering view against another. But with more novel situations and investment proposals, the AER's consultants will have to have the right kind of experience to make a meaningful contribution to the review process.

Expenditure forecasting necessarily takes place in the context of uncertainty. The length of the price control period is a factor in that. This is not to suggest that it is inappropriately long

[13] IPART, *Changes in regulated electricity retail prices from 1 July 2012, Draft report*, April 2012

– there needs to be a trade-off against the regulatory burden of more frequent reviews. However, change may come more quickly than the five year regulatory cycle. Customer response can be significant over this period, and take-up rates of technologies/innovations can change unexpectedly, especially if public policy unannounced at the time of the regulatory review drives it. The rapid take-up of PV in jurisdictions such as NSW in response to government subsidies is a case in point. Contingency provisions can play a part in managing these risks, but also critical is an appropriate incentive rate and return on investment.

AER proposal to impose high-strength, asymmetric capex incentives

The AER's proposal is for only 60 per cent of any overspend to be rolled into the Regulatory Asset Base (RAB) in the next price control. This represents an incentive rate in excess of 40 per cent. The exact amount will depend on the timing of the overspend, the cost of capital and the rules for applying depreciation. For example, if a DNSP overspends $100m in the first year of a price control and its cost of capital is 10 per cent, the present value of the future revenues it is allowed to collect in respect of that asset would be c. $39m. Thus the incentive rate is 61 per cent.

A low rate of recovery on incremental investment, especially where an NSP has exceeded its allowance, will make NSPs risk averse. It also shifts the balance of trade-offs. This will distort decision-making, particularly in new areas where a flexible approach from DNSPs is desirable. For example, a DNSP may trial a new technology at small scale and either curtail it if it's not proving successful or seek to ramp it up if it's getting results. Efficient decision-making in such circumstances requires balanced, reasonable incentives on both over-and under-expenditure.

The AER's rule change proposal leaves some ambiguity as to whether depreciation will also be deducted from the RAB[14]. Most of the DNSP's assets are very long-lived and so this will make relatively little difference to the incentive strength – for example a 50 year asset would deliver an incentive strength of 64 per cent. However, many of the newer technologies under consideration are information and communications technology assets and will typically have a much shorter life span. A 10 year asset would face an incentive rate of 77 per cent if it were depreciated before having the 40 per cent penalty applied.

The AEMC's directions paper discusses the possibility of ex post review as a means of imposing regulatory discipline of capital expenditure. This would be an unfortunate step as the possibility of the regulator disallowing capital with the benefit of hindsight increases regulatory risk. Such assessment is unlikely to fully account for all the uncertainties faced by the DNSP at the time it made the expenditure decision. Again this issue will be particularly acute when carrying out expenditure on new types of equipment or on customer engagement. It also applies where DNSPs spend money in response to expected customer behaviour such as the take-up of EVs or exporting from distributed generation. The DNSP may do so in good faith based on reasonable forecasts that then do not come to pass. It should not be penalised for doing so.

[14] "Depending on the depreciation framework adopted… there may also be a loss of depreciation.", AER Rule change proposal, p42

AER and Energy Users proposals on the cost of capital

Reducing the return on investments will lead to risk aversion. Smart grid initiatives typically involve taking a step into the unknown – utilising technology for the first time, engaging with customers and other parties in the supply chain differently. Thus there are likely, if anything, to be more and new risks entailed, emphasising the importance of maintaining an appropriately adequate cost of capital. The rule change proposals would reduce the likelihood of this happening. Firstly, the Major Energy Users' proposal makes the false argument that a publicly-owned DNSP faces a risk profile equivalent to that of its shareholding government. This is demonstrably not the case. Their proposal to for privately-owned DNSPs is to base the cost of the debt on a trailing average index. The principle of using a trailing average for at least part of the cost of debt merits further investigation, although to fully consider the complex implications of such an approach requires a process that goes beyond the AEMC's current process. If such an approach was considered, it would need to eb carefully designed to avoid the risk that a backward-looking reference point may fail to take proper account of factors that may affect the expected future cost of capital. The AER's proposal will bring undue inflexibility to the cost of capital determination process. Setting the cost of capital once every five years does not allow for consideration of relevant material changes in financing conditions in the interim.

This applies equally to transmission and gas networks. For transmission networks, this inflexible process has proved problematic and therefore there is merit in moving towards a process where the cost of capital can be reconsidered as required at each individual review. This is already the case for gas networks and so there is no need for change to the Gas Rules.

The consequences of a retreat from innovation and policy remedies - Case study: GB energy networks

The gas and electricity industries in Great Britain have been subject to independent regulation from their privatisation in the late 1980s. Over time, competitive elements of the sector were deregulated leaving the energy networks as the only elements subject to price regulation. It became apparent that a tough regulatory regime had undermined the economic rationale for innovation, i.e. research and development. In 2002/03 R&D expenditure intensity (R&D/turnover) was only 0.1 per cent compared to a benchmark of 2.5% for UK industry generally[15].

Accordingly the regulator, Ofgem has developed a number of specific incentives to encourage greater innovation spending by energy networks. The first of these was the innovation funding incentive (IFI), which was a pass through of 80% of qualifying R&D expenditure up to 0.5% of allowed revenue. This was supplemented by a specific incentive to encourage the connection of DG. The increasing penetration of DG and the need to manage the implications of this were a clear driver for the incentive schemes.

The IFI was extended from DNSPs to other energy networks and has continued into the subsequent price control period. However, the challenges of the future energy grid led Ofgem to add a further incentive, the Low Carbon Networks fund. The fund is paid for by a levy on all electricity distribution customers and DNSPs bid for a share of the total funding

[15] Ofgem, *Regulatory Impact Assessment for Registered Power Zones and the Innovation Funding Incentive*, March 2004, p5

available ($500m). This will allow DNSPs to carry out "trials to operate the network differently in order to increase the capacity of current network assets to facilitate the connection of Electric Vehicles, heat pumps and photo voltaic micro-generation; how best to provide timely and efficient connection for distributed generation; and the role that demand side response and electricity storage can play in future network operation."[16]

Such incentives may be worthy of consideration in the Australian context as the underlying objectives of the incentives match well with the sort of innovation that will be required of energy networks here. However, the right general regulatory settings for economic regulation of DNSPs may reduce the requirement for bespoke incentives. It's notable that under the existing Rules, DNPs have engaged in a wide range of initiatives, as described above. While some of these have benefited from government funding, DNSPs have still contributed resources whether direct financial inputs, or "in-kind". In other cases, the DNSP has funded the initiatives itself.

Customer engagement

The development of the future grid is highly dependent on customer choices and behaviour. Firstly, they will be the drivers of how the network is used through their consumption patterns, including the impact of self-generation, export, distributed storage and take-up of electric vehicles. It is important for them to understand the impact that these decisions have on the costs of the network and it is important for DNSPs to be able to accurately forecast take-up.

Cost is not necessarily the only impact. Customers consistently indicate that they value high levels of reliability. Maintaining these high levels may be challenging in the face of changing consumption and increased two-way flow. Smart networks technology can be an important part of the solution, but customers will need to recognise that reliability comes at a cost and that there are trade-offs to consider.

Further, the penetration of demand response tools such as dynamic pricing and direct load control will be dependent on customer understanding and acceptance of these tools.

Finally, these changes will not necessarily deliver cost and benefits equally across customers. Some may be worse off and where these are vulnerable customers it is important that appropriate protections for them are built into the policy frameworks.

These factors all point to the value of increased customer engagement and communication. This applies whether the DNSPs seek to have greater contact with end users directly or whether retailers (who already have a more direct relationship with users) act as an intermediary. While this will need to happen on an ongoing basis, it will also be valuable in the context of the price control process, since it is the outcomes of this process that will govern a DNSP's spending programme for the subsequent five year period (noting that the DNSPs will need to retain the flexibility to respond to changing circumstances). The value of customer engagement in price-setting processes was highlighted in Professor Littlechild's advice to the AEMC on the Rule change proposals. He notes that this is "increasingly playing a role in other regulatory jurisdictions".

[16] http://www.ofgem.gov.uk/Networks/ElecDist/lcnf/Pages/lcnf.aspx

Noting that small customers will need to be represented indirectly and that their representatives will need to be appropriately resourced to engage effectively in the process, this area is worthy of further exploration by the AEMC and stakeholders in the regulatory process. If the right from of engagement can be found, then DNSPs can be confident that their spending plans are line with customers' needs and expectations while customers can have confidence that their needs are recognised while understanding the cost of servicing those needs.

Innovation and benchmarking

Central to the Productivity Commission's review of Electricity Network regulation is the scope for greater benchmarking of NSP costs (the paper covers both distribution and transmission). The issues paper poses the question "is imperfect benchmarking still useful?" Imperfect benchmarking is in practice the *only* benchmarking available. Attempting to compare two different networks is fraught with complexity.

Firstly obtaining the relevant data on a suitably conformed basis is a significant exercise in itself and one that cannot be carried out exactly. Different businesses legitimately organise themselves in different ways and so their reporting systems do not necessarily record costs or operational data in exactly the same way.

Secondly, there are a number of relevant differences between networks and the conditions in which they operate that are hard to effectively control for. Australian NSPs operate over very different topographies and in very different climate conditions. Customer density varies very widely – from 4 customers per Km of network to 50[17]. Jurisdictional differences mean that they have to conform to different reliability planning standards, different planning and approvals processes for new infrastructure, different safety regimes, etc. Historical decisions on technology and varying timing of investment may have legacy impacts on maintenance costs and replacement cycles. These factors lead to a greater degree of heterogeneity than in other regulatory regimes where benchmarking is used, for example Great Britain, where the networks are much closer geographically, in size, density, and the regulations to which they are subject.

Thirdly, output measurement can prove challenging. In particular, accurately measuring the long-term condition of the network is difficult. Short-term reliability indicators may not be sufficient (and need to be adjusted for uncontrollable events such as extreme weather).

Fourthly and especially for transmission networks, investment can be very "lumpy", which hinders fair comparisons.

On top of these difficulties, the move to the grid of the future will add more dimensions of variability. On the one hand, networks may proceed at a different pace, particularly if they are reliant on government legislation to carry out full-scale rollouts of AMI, for example. This will mean that they spend more on certain activities, such as metering and communications in order to save money on others. Where networks choose to carry out a particular initiative, then one can expect that they have chosen what is an ultimately lower cost option. But there may be a timing mismatch between the cost and the benefits, so that what can be a more expensive choice in the short–term (and so appear less efficient on a simple snapshot

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[17] The Brattle Group, *Approaches to setting electric distribution reliability standards and outcomes*, January 2012, p25

comparison of costs) is cheaper in the longer term. Additionally, some of the benefits may be societal and so not captured by the DNSP, so that a more expensive option for the DNSP may deliver greater benefits overall.

On the other hand networks may be facing quote different operational challenges if consumer behaviour is different across different networks. An obvious example here is the issues arising from high penetration of PV, which may vary quite widely across networks depending on whether the climate is favourable and what jurisdictional subsidises are available. This adds another variation to control for.

None of this is to suggest that benchmarking cannot offer some insight into relative network performance, simply that any conclusions from benchmarking analysis must be treated with caution and not regarded as definitive.

Energy Supply Association of Australia

Analysis of initiatives to lower peak demand

Final Report

April 2012

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Contents

Executive summary

Introduction

Customer demand for electricity in Australia is closely related to weather. At times of extreme heat or cold (such as might occur over a few hours in each year) when a large proportion of people require more electricity to cool or heat their homes and businesses, the electricity supply system can become constrained.

The impact of this 'peak' demand is similar to a busy highway at peak hour. Adding an extra lane on the highway can alleviate congestion at peak times. However, outside of peak hour the additional lane is superfluous. Significant investment is made to upgrade the highway to cater for peak hour traffic, which is not used for most of the time.

Similarly, increasing the supply capacity of the electricity system to cater for extreme peak demand can alleviate supply congestion issues. However, the costs of augmenting the electricity system are significant, and like the additional lane on the highway, the additional capacity is only used for those times of extreme peak demand, which is typically only a few hours or days per year.

With the continued rapid growth in residential air conditioner penetration, the trend of strong growth in peak demand over the past decade is set to continue, driving increases in the costs of supplying electricity. Accordingly, measures to curtail or shift peak load have significant future potential value in terms of reducing growth-related infrastructure spending and, therefore, constraining rises in electricity prices.

The Energy Supply Association of Australia (ESAA) engaged Deloitte to undertake analysis of the potential benefits from initiatives to lower peak demand in Australia, based on high level estimates of the value of avoiding peak demand and publicly available results from trials and studies.

Initiatives considered in our study include:

- Dynamic pricing – time of use and critical peak pricing and incentives
- Direct load control of air conditioning and pool pumps
- Vehicle to Grid (V2G) capability of Electric Vehicles (EVs) and Plug-in Hybrid Electric Vehicles (PHEV)
- Energy efficiency measures targeted at reducing the drivers of peak demand, including:
    - Air conditioner appliance efficiency standards
    - Improvements in building standards for retrofitting
- Small scale solar generation.[1]

This report presents the results of our analysis of the high level benefits of implementing these initiatives to lower peak demand. Details on the potential costs to achieve are also presented for each modelled initiative. Our analysis was carried out by desktop research of publicly available trial results and models, based primarily on Australian data.

[1] We note that our analysis of improvements in building standards are related to savings generated by commercial customers and small scale solar savings will be delivered by both residential and commercial customers.

Results of our analysis

Our analysis has estimated that the economic value of the combined potential gross benefits due to peak demand reductions delivered by the six initiatives we have studied ranges between $1.5 and $4.6 billion, over 2012-13 to 2021-22. The following table summarises the estimated gross benefits for each initiative.

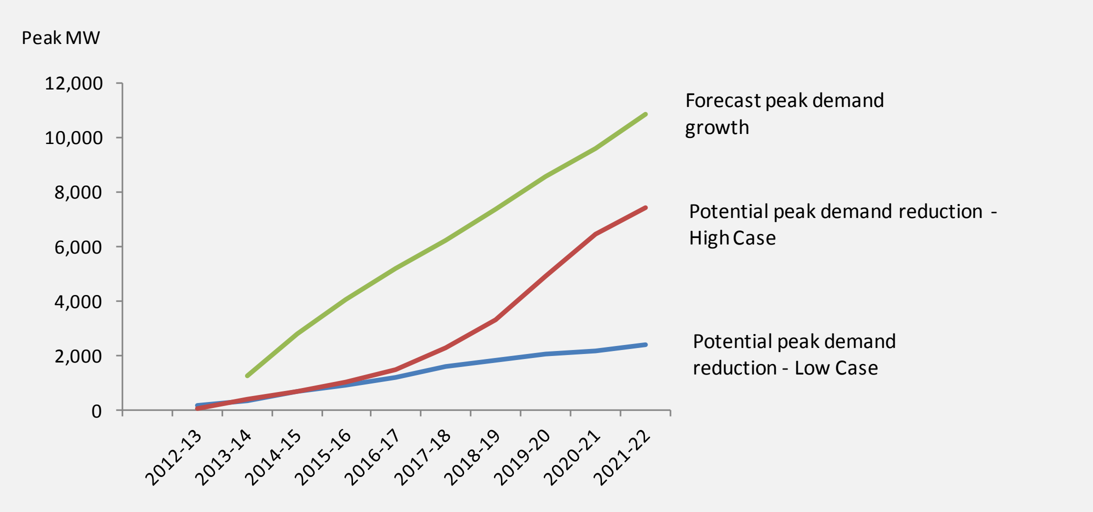
Table 1: Deloitte conclusion – Total estimated value of gross benefits 2012-13 to 2021-22 (NPV, $m)

Initiative	Low case benefits ($m)	High case benefits ($m)
Time of use pricing	58	193
Critical peak pricing and incentives	385	1,272
Direct load control of air conditioners	200	1,338
Direct load control of pool pumps	188	231
Electric vehicles	60	537
Energy Savings Measures	361	486
Enhanced uptake of Solar PV	300	528
Total gross benefits	**1,551**	**4,585**

Source: Deloitte analysis. Note that totals may not sum due to rounding.

The estimated reduction in total demand from these initiatives ranges between 2,382 and 7,410 MW. The sum of potential peak demand reductions under the high and low case scenarios, as well as the forecast peak demand for Australia's two main electricity systems are presented in the following graph.

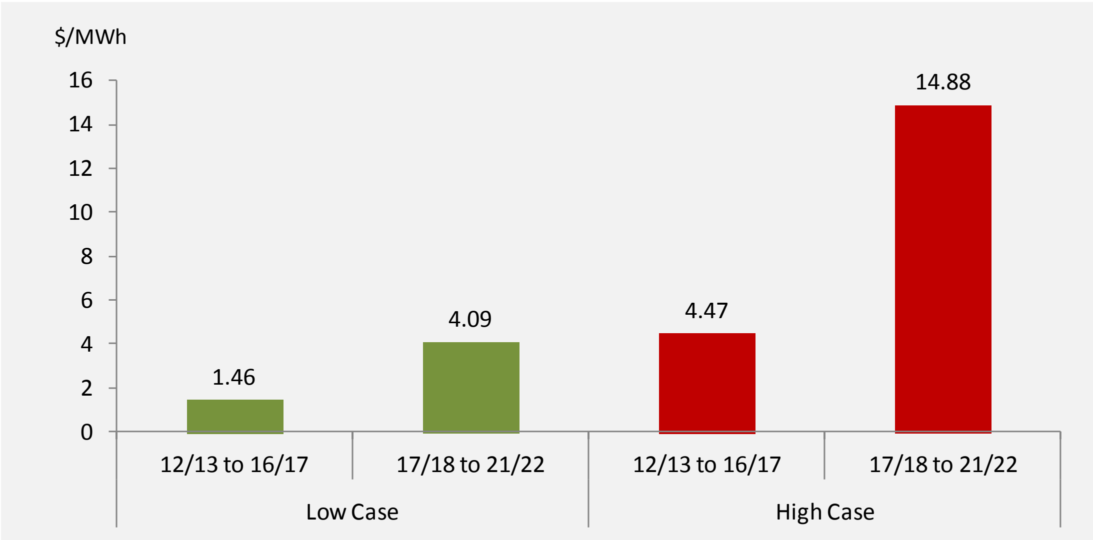
Figure 1: Conclusion –potential peak demand reductions (MW)



Source: Deloitte analysis

To determine the precise impact on electricity tariffs is beyond the scope of this study and depends upon the costs incurred to achieve these benefits. However, we have converted these calculated gross benefits into $/MWh estimates for the residential market, based on forecast residential electricity consumption.

Figure 2: Domestic gross benefits converted into $/MWh



Source: Deloitte analysis

The gross benefits translated into a $/MWh figure for residential customers range from an average of $1.46/MWh to $4.09/MWh under the low case scenario and $4.47/MWh to $14.88/MWh under the high case scenario.[2] It is noted that the net benefits actually realised by customers will depend upon the additional cost incurred in achieving these benefits, the regulatory framework and the competitive nature of the wholesale and retail markets.

Putting aside the benefits associated with improving the energy efficiency of existing commercial buildings, in making this calculation, we have implicitly assumed that all benefits accrue to residential customers.

This report has demonstrated that there are significant potential benefits associated with lowering peak demand in Australia. Accordingly, we recommend that industry, policy makers, regulators and consumer representatives undertake further analysis of these initiatives, including detailed cost benefit analyses incorporating peak demand impacts.

Peak Demand growth

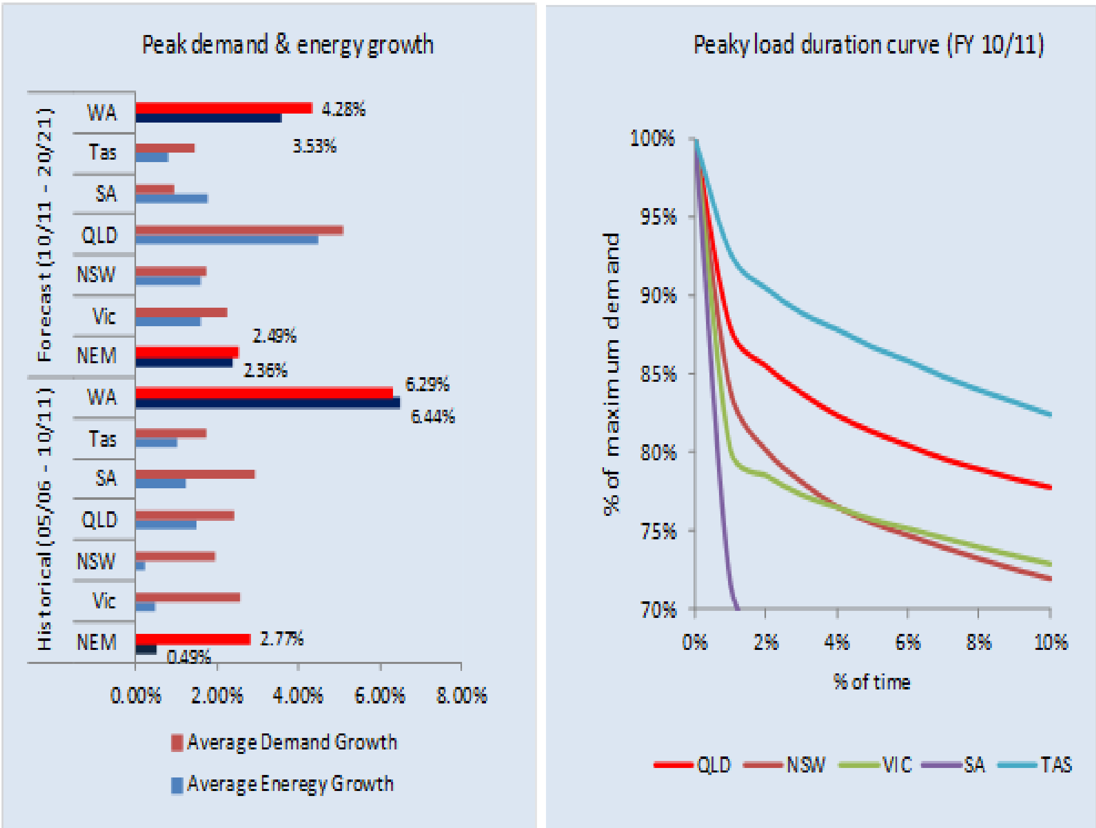
Peak demand growth is a major driver of investment for electricity network and generation businesses. In recent years, peak demand has grown faster than energy consumption, resulting in higher average prices for electricity. Slowing average energy consumption has been attributed in various analyses to a downturn in economic growth affecting both commercial/industrial and residential energy consumption as well as a general economic shift away from the more energy intensive manufacturing sector towards the services sector in Australia. It is also likely that energy efficiency measures have started to impact energy consumption. Despite slower energy

[2] In undertaking this calculation, we have assumed that the average residential customer consumes approximately 7 MWh per annum.

consumption, peak demand has continued to grow and this relationship is partly responsible for energy prices in many States rising faster than in the recent past.[3]

The following graph presents historical and forecast energy and peak demand for each state in the NEM and the Western Australian SWIS over 2005-06 to 2020-21. Load duration curves for each NEM state are also presented, which reflect the proportion of time over which peak demand is occurring. The needle-peaks on the load duration curves highlights that the top 20% of maximum demand occurs for less than 2% of time. This implies that assets which are built to meet peak demand are significantly underutilised.

Figure 3: Peak demand and energy growth - NEM and SWIS



Sources: AEMO 2011 SOO, IMO 2011 SOO, Deloitte analysis of Net System Load Profile data for the NEM.

Over the period 2011 to 2021, peak demand is forecast to grow at an average of 2.49% in the NEM and 4.28% in the Western Australian SWIS, driving the need for investment in network and generation assets. Therefore, given the peaky nature of the load duration curves, considerable cost savings can be achieved if initiatives to reduce peak demand are implemented.

The value of reducing peak demand

As detailed market modelling was beyond the scope of this project, for the purposes of analysing the potential financial value of initiatives to reduce peak demand, we have adopted a high level estimate of $200 per kW per annum as the value of avoiding an incremental kW of demand.

In selecting this value, we have taken into account the long run marginal cost (LRMC) of electricity network and generation investments, as well as high level estimates used in similar previous studies.

[3] Other drivers of electricity price growth include increased reliability standards and rising input costs. Growth in asset replacement expenditure has also contributed to higher energy prices.

We have also taken into account a number of factors relevant to the specific initiatives under analysis, and accordingly would caution the use of this high level estimate for other purposes.

We note that investment in electricity assets is driven by load at diverse sections of a network, and accordingly, reducing coincident peak demand will not result in avoided investment at every point of constraint on the network. In addition, planning for network and generation augmentation investment is needed several years prior to peak demand exceeding capacity. Reducing peak demand may not result in an immediate deferral of investment, but it should reduce investment in the long term.

In addition, in order to defer investment, network operators, generators and retailers need to be confident on the potential reduction in demand occurring at times of peak, given the commercial implications of not having the capacity or not being contracted to meet peak demand.

Traditionally, demand side participation is valued based on firm contracts between demand side providers (customers) and market participants. Most of the demand reductions associated with initiatives discussed in this paper (such as Dynamic Pricing) will not be underpinned by contracts requiring firm demand reductions. Rather, they will be based on incentives to change behaviour. Therefore, for market participants to incorporate demand reductions into their investment planning, historical data reflecting reliable demand reductions due to the initiatives will be needed. This will only occur over the longer term, reducing the value of avoided investment in the 10 year timeframe of this analysis.

Initiatives to reduce peak demand

Following our research and consultation with the esaa, we have selected five core policy initiatives for the focus of this review, including:

- Dynamic pricing – time of use and critical peak pricing and incentives
- Direct load control of air conditioning and pool pumps
- Vehicle to Grid (V2G) capability of Electric Vehicles (EVs) and Plug-in Hybrid Electric Vehicles (PHEV)
- Energy efficiency measures targeted at reducing the drivers of peak demand, including improvements in building standards for retrofitting
- Small scale solar generation.

In the process of selecting these core policy initiatives, several other initiatives were identified and researched, however, a lack of reliable, recent research prevented quantification of potential benefits.

Dynamic pricing

Economic theory suggests that charging customers prices that reflect the different costs of supplying electricity at different times of the day (sometimes known as flexible pricing) is one of the fundamental ways to reduce peak demand and ensure economically efficient consumption behaviour. There are a number of different ways that flexible pricing can be undertaken, which for convenience we have grouped together as Dynamic Pricing.

For the purposes of our analysis, we have defined Dynamic Pricing as constituting the following:

- Three-rate TOU tariffs (peak, shoulder, off peak), for which rates may vary between seasons (winter, summer) however otherwise remain fixed for the contract period
- Critical peak pricing and/or critical peak incentives, which involve at least one-day ahead notification being sent to customers to advise them of a critical peak pricing event. During a critical peak pricing event, electricity prices would be significantly higher than normal TOU

peak prices. Alternatively, during a critical peak pricing event, customers could be paid an incentive for reducing their demand from a determined baseline by an agreed amount.

Trials of Dynamic Pricing are being undertaken by distributors and retailers in Australia and in many locations worldwide. We have reviewed a sample of trial and research results in estimating the potential value of Dynamic Pricing in reducing peak demand.

The range of Australian time of use studies and trial results we reviewed spans from 1.1% to 13% peak load reduction, while the range of results of international trials and studies spans from -4% to 18%. The potential peak load reductions achieved by critical peak pricing trials and studies we studied are significantly greater than those for time of use pricing, ranging between 10.6% and 36% in Australia and 4% to 40% internationally.

Based on our experience and research, we have selected the following high and low estimates of customer responses to Dynamic Pricing in calculating the range of possible benefits.

Table 2: Dynamic Pricing – Deloitte peak load reduction assumptions

	Low estimate (% response)	High estimate (% response)
Time of use tariffs	1.5%	5%
Critical peak pricing or incentives	10%	33%

Source: Deloitte analysis

Based on our analysis of Australian and international studies and trials, and the estimated value of reducing peak demand discussed above, we consider that the implementation of Dynamic Pricing across the NEM and SWIS over 2012 to 2022 offers benefits in the range set out in the table below. These values are based on maximum take up rates of 30% of customers being engaged in both time of use and critical peak pricing or incentives from 2017-18, which we consider is a reasonable estimate of achievable engagement over the period of analysis.

Table 3: Dynamic Pricing – estimated value of benefits 2012-13 to 2021-22 (NPV, $m)

	Low case estimate ($m)	High case estimate ($m)
Time of use pricing	58	193
Critical peak pricing / incentives	385	1,272

Source: Deloitte analysis

Direct load control

Direct load control has been used by electricity distributors to control residential electric storage hot water systems across Australia for over 30 years. It is not surprising, therefore, that direct load control of air conditioning and pool pumps – two of the major drivers of peak demand in Australia over the past decade – is now being trialled by distributors across the country.

The best-known and most extensive Australian trials of direct load control of air conditioning to date have been conducted by ETSA Utilities and Energex.

Since 2006, ETSA Utilities has conducted several direct load control trials targeting residential and commercial volunteer customers' air conditioning. Results of these trials indicated that the potential reduction in each customer's peak load ranges from 19% to 35%.[4] Energex's Cool Change Trial, which commenced in the summer of 2007 and is still in operation, involves trialling direct load control of over 2,000 customers' air conditioners. On average, participating customers reduced their demand by 13% over the 2009-10 summer peak.[5]

After reviewing the ranges of achievable reductions in published trials, we have adopted the peak load reduction assumptions as set out in the table below.

Table 4: Direct load control – Peak reductions per customer

	Peak reductions per customer - Low case (% per average customer peak load)	Peak reductions per customer - High case (% per average customer peak load)
Direct load control of air conditioners	11.7%	35.0%
Direct load control of pool pumps	27.0%	36.0%

Source: Deloitte analysis

Using a base assumption of average customer contribution to peak of 3 kW, ABS data on air conditioner penetration, and pool pump ownership forecasts developed by a consultant to the Department of Environment, Water, Heritage and the Arts, our estimates of the potential benefits of direct load control are presented in the following table.

Table 5: Direct load control – estimated value of benefits 2012-13 to 2021-22 (NPV, $m)

	Low case estimate ($m)	High case estimate ($m)
Direct load control of air conditioners	200	1,338
Direct load control of pool pumps	188	231

Source: Deloitte analysis

Vehicle to Grid – Electric and Plug in Hybrid Vehicles

Recent Australian studies on Electric Vehicles (EVs) and Plug in Hybrid Electric Vehicles (PHEVs) have optimistically forecast that customer take-up in Victoria will be in the order of 50% of new car sales (more than 100 000 EVs) by 2015, and a similar magnitude in NSW by 2018.[6]

Many research papers on EVs highlight the potential benefits for the electricity market and system that could be generated by the widespread adoption of EVs. In particular, several research papers suggest that EVs present an opportunity to support intermittent renewable generation with baseload storage.[7] However, to date there has been relatively little research done on the vehicle to grid (V2G) peak load support capability for EVs internationally, let alone in Australia.

[4] ETSA Utilities, Project EPR 0022 – Response to AEMC Issues Paper – Power of Choice, September 2011.
[5] Energex, Time for a cool change – Energy Smart Suburbs – Newsletter November 2010.
[6] AECOM, Forecast Uptake and Economic Evaluation of Electric Vehicles in Victoria, Final Report, May 2011; AECOM, Economic Viability of Electric Vehicles - Department of Environment and Climate Change (NSW), September 2009.
[7] Curtin University of Technology, Electric Vehicles and their Renewable Connection – How Australia can take part in the Green Revolution, presentation, June 2009.

The CSIRO and the Institute for Sustainable Futures are together undertaking a comprehensive assessment of potential EV uptake and use under Australian conditions. The Electric Driveway Project will run over three years and explore the potential synergies between the electricity and transport sectors presented by EVs.

Using the findings reported in a range of studies we have developed a range of potential battery capacity and assumptions regarding availability of cars and battery capacity for V2G supply. Our assumptions are presented in the following table.

Table 6: V2G capability - Deloitte Assumptions

Benefits assumptions	Low case	High case
Maximum capacity per vehicle	10 kWh	24 kWh
% cars available at peak time	40%	60%
% of each car's load available at peak time	40%	50%
Discharge time	8 hours	4 hours

Source: Deloitte analysis

In order to present the potential benefits that initiatives to support the take up of EVs could hold for Australia, we have examined the benefits associated with a take up rate in line with the EV and PHEV forecasts prepared by AECOM for NSW and Victoria, extrapolated for the other States. We consider that the penetration of electric vehicles in Australia over 2012 to 2022 offers benefits in the range set out in the table below.

Table 7: Electric Vehicles – estimated value of benefits 2012-13 to 2021-22 (NPV, $m)

	Low case estimate ($m)	High case estimate ($m)
Electric vehicles (V2G)	60	537

Source: Deloitte analysis

Energy efficiency measures – Implementing improvements in building standards

Improving the energy efficiency of buildings reduces their overall heating and cooling load, and also reduces peak demand.

In recognition of the potential savings due to lower peak demand delivered by energy efficiency, and the lack of research into these benefits in 2010 the Department of Climate Change and Energy Efficiency commissioned a national study into the peak demand benefits of various measures to improve the energy efficiency of buildings. The Building Our Savings study was jointly carried out by the Institute for Sustainable Futures and Energetics.[8] The focus of this study was on the savings generated by retrofitting existing buildings, particularly commercial buildings. Energy savings measures that were modelled as part of this study include:

- Commercial measures: Voluntary Energy Star Program designed to identify and promote energy efficient products; Maintenance and cleaning of filters and coils of air handling, air conditioning, pumping and electrical heating appliances; Fine tuning and maintenance of

[8] Institute for Sustainable Futures and Energetics, Building Our Savings: Reduced Infrastructure Costs from Improving Building Energy Efficiency, Final Report, July 2010.

lighting systems, sensors and controls; Installation of high energy efficiency air conditioning and dynamic lighting systems with controls; installation of more efficient air handling equipment

- Residential measures: Hot water demand reduction; Fridge buy-back scheme; Draught sealing; installation of new efficient lighting, hot water unit and air conditioners; installation of roof insulation
- Industrial measures: installation of new efficient lighting; Green-IT retrofits (affecting servers and power supplies); installation of LED lighting.

The study's estimates of the impact on summer peak demand are set out in the following table.

Table 8: Building Our Savings study – Reported results – summer peak demand

	Moderate scenario	Accelerated scenario
Maximum seasonal peak demand reduction (MW)	5,283	7,236
% of 2020 summer peak demand eliminated	10%	13%
% of 2010 to 2020 peak growth eliminated (Summer)	43%	58%

Source: Institute for Sustainable Futures and Energetics, Building Our Savings: Reduced Infrastructure Costs from Improving Building Energy Efficiency, Final Report, July 2010.

After reviewing the Building Our Savings study, we consider that the implementation of these measures to improve the energy efficiency of commercial, residential and industrial buildings over 2012 to 2022 offers benefits in the range set out in the table below.

We note the potential for further benefits associated with increasing the energy efficiency standards of new buildings, however, more research is needed to determine the peak demand savings from such measures.

Table 9: Energy Savings Measures – estimated value of benefits 2012-13 to 2021-22 (NPV, $m)

	Low case estimate ($m)	High case estimate ($m)
Energy Savings Measures from the Building Our Savings study – potential value of reduced MW	361	486

Source: Deloitte analysis

Distributed generation

There has been a rapid increase in small scale solar generation in Australia over the past decade, driven principally by a reduction in the upfront capital costs and government initiatives stemming from the Renewable Energy Target and other direct incentives, such as feed-in-tariffs.

While generation situated close to the point of demand has the potential to reduce the use of network to transport electricity, research suggests that the performance of small scale solar generation at times of peak demand is not close to capacity. This is because times of summer peak demand are not closely correlated with peak sunlight and PV generation. In addition, high temperatures reduce the potential output of PV.

Based on recent studies by Ausgrid, Western Power and the AEMC, we have developed a range for the estimated impact of solar PV on summer maximum demand, per MW of installed PV capacity, as presented in the following table.

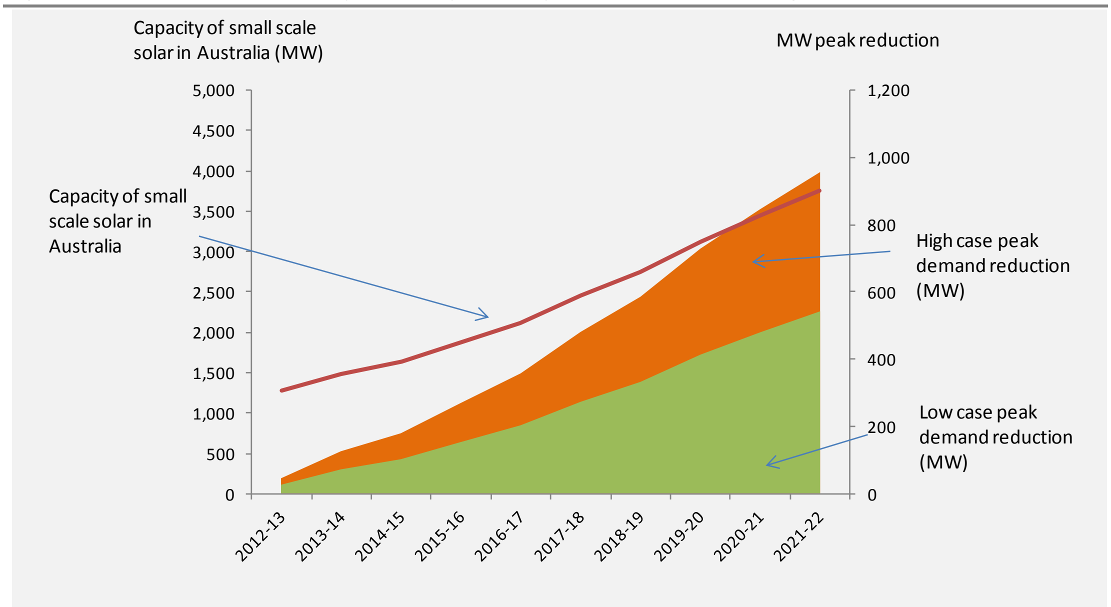
Table 10: Deloitte assumptions – Impact of PV on summer peak demand

	Low case estimate (%)	High case estimate (%)
Reduction at summer peak per MW of installed capacity - NEM	20.9%	34.9%
Reduction at summer peak per MW of installed capacity - SWIS	20.9%	51.6%

Source: Deloitte analysis

Using a publicly available forecast of Solar PV take up, extrapolated out to 2021-22, our assumptions regarding PV take up and the potential peak load reduction are presented in the following graph.

Figure 4: Small scale solar – Take up rate and potential peak load reductions – high and low case scenario



Source: Deloitte analysis

Using these assumptions, we consider that the Enhanced PV Uptake scenario over 2012 to 2022 could result in the range of benefits, as set out in the table below.

Table 11: Enhanced Uptake of solar PV– estimated value of benefits 2012-13 to 2021-22 (NPV, $m)

	Low case estimate ($m)	High case estimate ($m)
Enhanced uptake of Solar PV	300	528

Source: Deloitte analysis

Conclusion

In conclusion, our analysis of the available research and data relating to seven initiatives has yielded a total range of gross NPV benefits of between $1.6 billion and $4.6 billion over 2012-13 to 2021-22. The results are presented in the table below.

Table 12: Deloitte conclusion – Total estimated value of gross benefits 2012-13 to 2021-22 (NPV, $m)

Initiative	Low case benefits ($m)	High case benefits ($m)
Time of use pricing	58	193
Critical peak pricing and incentives	385	1,272
Direct load control of air conditioners	200	1,338
Direct load control of pool pumps	188	231
Electric vehicles	60	537
Energy Savings Measures	361	486
Enhanced uptake of Solar PV	300	528
Total gross benefits	**1,551**	**4,585**

Source: Deloitte analysis

The net benefits realised by customers will depend upon the additional costs incurred to achieve these benefits, the regulatory framework and the competitive nature of the wholesale and retail markets. For each initiative, we have presented an indication of the core costs that are likely to be incurred in achieving these benefits.

A significant proportion of the potential benefits are attributable to critical peak pricing incentives and direct load control of air conditioners. Under the high case scenario, we note that the take up rates reach a maximum of 30% for all residential customers for Dynamic Pricing and 16% for direct load control of air conditioning .

Assuming that the peak load reduction benefits of Dynamic Pricing and direct load control are delivered by different residential customers (implying that the maximum benefit can be derived from each initiative as each customer responds to each initiative to highest degree possible) results in 46% of residential customers being engaged. We consider this is a reasonable assumption, given the current technical, market and policy barriers to these initiatives.

If we assume that each residential customer is only engaged in a single initiative (either Dynamic Pricing, direct load control, V2G or solar PV), the result is a maximum of 59% of residential customers being engaged in 2021-22 under the high case scenario and 49% of customers under the low case scenario.

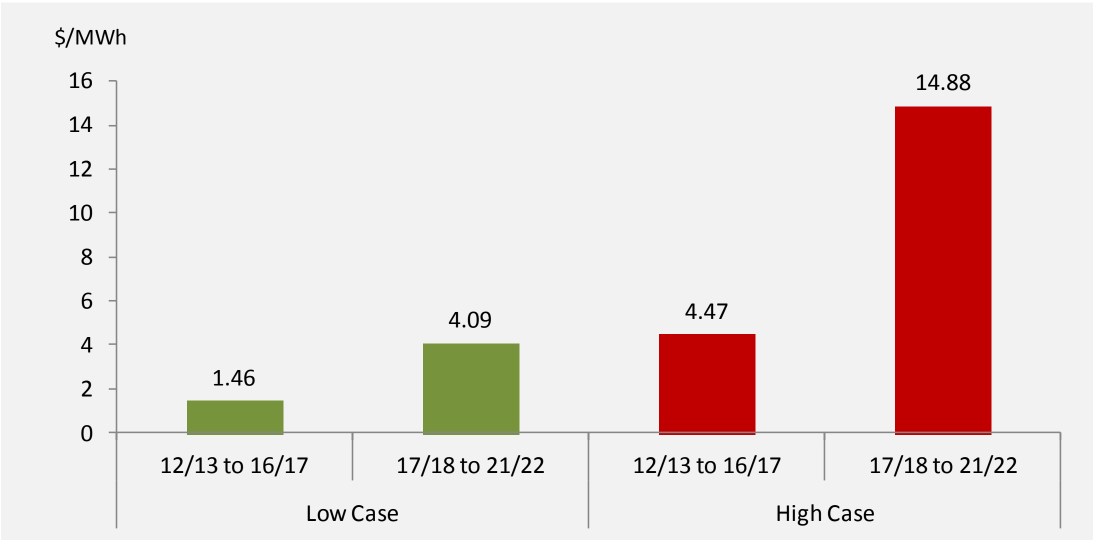
For building efficiency standards, the benefits we have estimated are to be delivered by retrofitting existing commercial buildings, targeting peak demand savings delivered by commercial customers.

We therefore believe that the benefits from the seven initiatives can be added without overstating the total benefits of reducing peak demand.

To determine the precise impact on electricity tariffs is beyond the scope of this study and depends upon the costs incurred to achieve these benefits. However, we have converted these calculated gross benefits into a $/MWh estimate for the residential market based on forecast residential electricity consumption. The results are presented in the figure below.

Putting aside the benefits associated with improving the energy efficiency of existing commercial buildings, in making this calculation, we have implicitly assumed that all benefits accrue to residential customers.

Figure 5: Domestic gross benefits converted into $/MWh

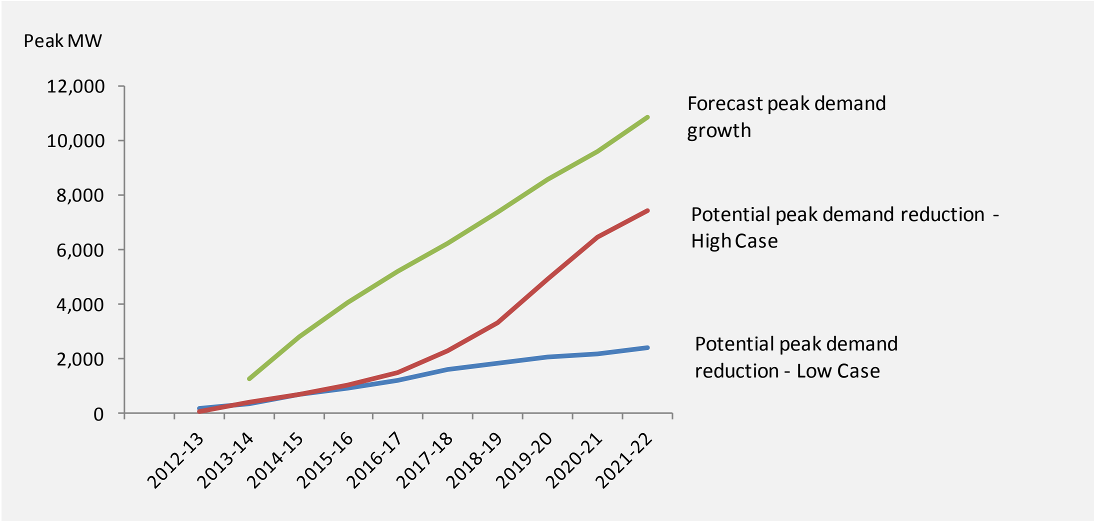


Source: Deloitte analysis

The gross benefits translated into a $/MWh figure for residential customers range from an average of $1.46/MWh to $4.09/MWh under the low case scenario and $4.47/MWh to $14.88/MWh under the high case scenario. The actual electricity price impact for residential customers will be lower due to the additional costs incurred in achieving these benefits. The electricity price impact will also depend upon the regulatory framework and the competitive nature of the wholesale and retail markets.

The sum of potential peak demand reductions under the high and low case scenarios, as well as the forecast peak demand for Australia's two largest electricity systems are presented in the following graph.

Figure 6: Conclusion –potential peak demand reductions (MW)



Source: Deloitte analysis

This report demonstrates that there is significant value to be pursued in initiatives to lower peak demand over the next decade. Under the high case scenario, we estimate that the initiatives considered could reduce peak demand growth by 68% by 2021-22.

1 Introduction

1.1 Peak demand in Australia

Significant, sustained growth in peak demand in Australia over the past decade has been a major driver of rising electricity costs. With the continued rapid growth in residential air conditioner penetration, driven in part by falls in the upfront cost of these appliances, this trend is expected to continue.

Analysis of load duration curves for 2010-11 published by AEMO, which show the proportion of time over which demand has occurred, indicates that for the 'peakiest' NEM regions of South Australia and Victoria, the top 20% of load occurs for less than 2% of the year, or around three days. The conclusion which can be drawn is that a significant amount of electricity network and generation assets which have been built to serve the top 20% of peak demand in these regions, are used for only around three days per year. In NSW and Queensland, the top 10% of peak demand is served over less than three days per year.

Accordingly, measures to curtail or shift this peak load have great potential to reduce growth-related infrastructure spending and, therefore, constraining rises in electricity prices. Network businesses across Australia have recognised this value and in recent years have undertaken a large number of trials and studies on ways to reduce peak demand, successfully lowering the costs of serving their customers.

This value has also been recognised by government, in particular the Ministerial Council on Energy (MCE) and the Australian Energy Market Commission (AEMC). Since 2007, the AEMC has been undertaking a detailed investigation into the potential for amendments to electricity regulations to support demand side participation in the NEM.[9] The Australian Energy Regulator (AER) has also developed a Demand Management Incentive Scheme (DMIS) which is applied to distributors in the NEM to encourage investigation of innovative ways to reduce peak demand.[10]

The purpose of this paper is to present, at a high level, the costs of meeting peak demand in Australia, and the potential value of a range of initiatives to lower peak demand. Our analysis is largely based on the findings of a range of Australian trials and studies, as well as international research outcomes that are applicable to the Australian context.

We note that while we have relied on many published trials and studies in developing this analysis, we do not necessarily endorse all of the methods and data used in those studies, nor the individuals and organisations we have referred to in this report. However, we do consider that the research results we have relied upon in generating our estimated peak demand savings are sound, and are among the most relevant and recent available results.

1.2 Scope of our work

As set out in the terms of reference prepared by the ESAA, the scope of work for this analysis involves illustrating, at a high level, the potential financial benefits for Australia of flattening of the load profile. This load profile is currently getting peakier and thus exacerbating cost pressures in the industry. This work comprises the following key parts:

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[9] AEMC, Review of Demand Side Participation in the NEM – Stage 3: Power of Choice. Details available at: http://www.aemc.gov.au/Market-Reviews/Open/Stage-3-Demand-Side-Participation-Review-Facilitating-consumer-choices-and-energy-efficiency.html Accessed 28 February 2012.

[10] For example: AER, Demand Management Incentive Scheme - Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011–15, April 2009 , available at: http://www.aer.gov.au/content/item.phtml?itemId=728015&nodeId=7c4f21724ea53a38a35b6a019c65f48d&fn=Final%20Demand%20Management%20Incentive%20Scheme%20for%20Victorian%20DNSPs.pdf Accessed 28 February 2012.

- Estimating the financial impact of increasing peakiness over a ten year period
- Estimating the costs and benefits of a series of plausible tools, including policy reforms and technological innovations which aim to flatten the load profile over the same period, including:
    - Dynamic pricing, including time of use, peak rebates and critical peak pricing
    - Direct load control of appliances
    - Cost effective storage
    - Cost effective energy efficiency measures targeted at peak demand
    - Advanced communication and network monitoring systems which enable operators to manage increases in demand without increasing supply
    - Electric vehicles.

This analysis aims to produce an estimate of the range of total possible cost savings or benefits associated with flattening the load profile.

As requested, the focus of the analysis has been at a national level, however, consideration has been given to whether there are likely to be differential outcomes for networks and generators within the NEM and Western Australian or other electricity markets. Detailed analysis on the location-specific impacts of different technologies was beyond the scope of this engagement.

Our analysis was carried out by desktop research of publicly available trial results and models, based primarily on Australian data.

2 Peak demand and energy growth in Australia

2.1 Historical trends

In identifying growth trends in peak demand and energy consumption across the NEM and the South West Interconnected System (SWIS) over the past decade, we have reviewed data published in the Electricity Statement of Opportunities (SOO) reports produced by the Australian Energy Market Operator (AEMO) and the Western Australian Independent Market Operator (IMO).[11] The annual SOO reports provide a reliable, consistent analysis of energy use over time in the NEM and the SWIS.

We acknowledge that whole of system peak demand forecasts can be considered misleading in terms of identifying the drivers of distribution network investment, as the need for new distribution capacity is actually driven by peak demand at particular locations on the network, which may not occur at the same time as system peak. However, we consider that the growth in the system level peak demand is reflective of the general trend across the network driving growth related expenditure.

While historically winter peak demand has driven the need for new investment in electricity infrastructure, caused largely by electric heating and storage water heating loads, the increased penetration of both gas heating and air conditioning has seen a switch to the majority of investment driven by summer coincident peaks. Evidence shows that peak demand is increasingly correlated with high ambient temperatures, which causes additional problems for electricity networks, as equipment performance is also eroded by high temperatures. Given the overarching trend of growth in summer peak demand, our analysis is focussed on reducing summer peaks, however, we note that in Tasmania and in some regional locations in other States, high winter peak demand is also driving network investment. Accordingly, in addition to the initiatives focussed on reducing summer peak demand discussed in this report, winter initiatives such as load control of electric hot water systems remain important tools for management of peak demand going forward.

The AEMO 2011 SOO presents actual energy (sent-out) and maximum demand (POE 50) data for 2005-06 to 2009-10, and estimates for 2010-11. The five year average historical growth rates are:

- Energy – 0.5% per annum
- Summer maximum demand – 2.8% per annum.[12]

The IMO 2011 SOO does not present historical data on energy and maximum demand in the SWIS. Reviewing data published by Western Power reveals the following actual historical growth rates over 2005-06 to 2009-10, and estimates for 2010-11:

- Energy – 6.4% per annum
- Summer maximum demand – 6.3% per annum.[13]

[11] AEMO, Electricity Statement of Opportunities for the National Electricity Market, 2011; Independent Market Operator, Statement of Opportunities, June 2011. We note that in March 2012, AEMO released an update to its 2011 SOO, reporting lower energy consumption and peak demand driven by changes in economic conditions and an increased take up of energy efficiency and distributed generation, particularly rooftop solar. While our analysis is based on the 2011 SOO figures, we consider AEMO's changed forecast does not affect our analysis of the benefits of peak demand reduction. As peak demand continues to grow, requiring investment in infrastructure and driving increases in electricity prices, benefits associated with lowering peak demand are increasingly relevant. We also note that the March update provided by AEMO did not contain sufficient information to enable us to amend the ten year energy and maximum demand forecasts for the NEM. AEMO, 2011 Electricity Statement of Opportunities, Update as at 2 March 2012.

[12] AEMO, Electricity Statement of Opportunities for the National Electricity Market, 2011, Chapter 3

This comparison between the NEM and SWIS reveals the significant differences in average economic growth in the Eastern and Western states. Increasing demand from the resource sector, compounded by annual population growth of 2.2% in recent years is driving growth in both energy consumption and peak demand in the SWIS.[14] Western Power's 2011 Annual Planning Report presents an analysis of the deterioration of average system utilisation (being the average proportion of time that the network is fully utilised, or the load factor) on its network falling from 61% to 57% over 2000-01 to 2010-11, demonstrating increasingly sharp peak demand.[15]

2.2 Forecast growth

AEMO has forecast that growth in energy and peak demand in the NEM states will converge, as recovery from the economic slowdown builds momentum. AEMO has cited the following specific drivers of growth from 2011:

- Mining activity, LNG developments and flood related construction in Queensland
- Improving economic growth in Victoria, with industrial loads forecast to return to historical levels
- Improving economic growth and mining expansion plans in South Australia
- Increases in agriculture and mining activity and population growth in Tasmania.[16]

AEMO's medium scenario growth forecasts for the NEM over the next decade are:

- Energy - 2.4% per annum
- Summer maximum demand - 2.5% per annum (POE 50).

The IMO has forecast maximum demand and energy growth on the SWIS in its 2011 SOO, with growth driven by expected large new loads and strong economic growth. The IMO's energy and maximum demand growth forecasts for the SWIS over 2010-11 to 2021-22 are:

- Energy (expected case) – 3.5% per annum
- Summer maximum demand (expected economic growth) – 4.3% per annum (POE 50).[17]

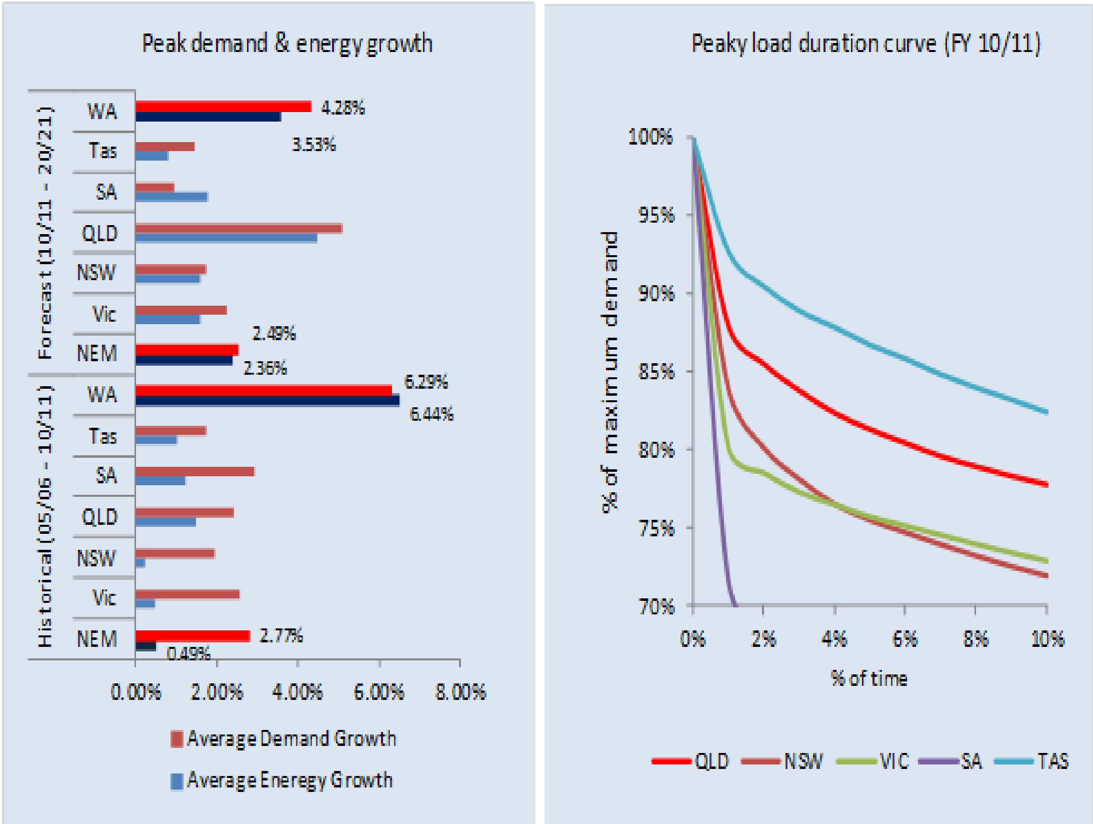
These forecasts show that there is some expectation that energy consumption in the NEM will grow at a similar rate to peak demand going forward, while in the SWIS, energy consumption growth will fall behind peak demand growth.

As outlined in the previous section, both of these long term forecasts run counter to the last five years of growth data reported by AEMO and the IMO, for a variety of different reasons. While it is clearly difficult to project the growth rate differential between energy and peak demand, the clear forecast is that growth in peak demand will continue, driving new investment and increasing the costs of supplying electricity.

The following graph presents historical and forecast energy and peak demand for each state in the NEM and the Western Australian SWIS over 2005-06 to 2020-21. Load duration curves for each NEM state are also presented, which reflect the proportion of time over which peak demand is occurring. The needle-peaks on the load duration curves highlight that the demand driving significant growth-related investment occurs over less than 2% of time.

[13] Western Power, Access Arrangement Information for 2012-17 - Appendix P - System Demand Forecasting for AA3 and Appendix T – Deloitte Report – Energy and Customer Number forecasts for the AA3 Period; Independent Market Operator, Statement of Opportunities, June 2011, Appendixes 3, 4 and 5.
[14] ABS, WA Population Growth – 1367.5 – Western Australian Statistical Indicators 2010.
[15] Western Power, 2011 Annual Planning Report, Chapter 4 – Demand Forecasting.
[16] AEMO, Electricity Statement of Opportunities for the National Electricity Market, 2011, p. 3-1.
[17] Independent Market Operator, Statement of Opportunities, June 2011, Appendixes 3, 4 and 5.

Figure 7: Peak demand and energy growth - NEM and SWIS



Sources: AEMO 2011 SOO, IMO 2011 SOO, Deloitte analysis of Net System Load Profile data for the NEM.

2.3 Conclusion

Summer peak demand in the NEM has grown at an average rate of 2.8% per annum over the past five years and 6.3% per annum in the SWIS. Forecasts for both markets show peak demand growing at a fast rate over the next decade, which will require substantial new investments in network and generation capacity.

The relationship between peak demand and energy consumption has important implications for average energy prices. Increasing growth related network investment, coupled with slowing energy consumption, results in higher average prices for electricity, as network businesses recover the growing costs of their investments over energy sales which are growing at an increasingly slower rate. In recent years, while peak demand has continued to rise significantly in most States, growth in energy consumption has slowed in the NEM. This has been attributed in various analyses to a downturn in economic growth affecting both commercial/industrial and residential energy consumption as well as a general economic shift away from the more energy intensive manufacturing sector towards the services sector in Australia. It is also likely that energy efficiency measures have started to impact energy consumption. This trend is partly responsible for energy prices in many States rising faster than in the recent past.[18]

Having established that peak demand is growing and is expected to continue to grow, the following section discusses methodologies for determining the cost of meeting peak demand, and the value of lowering peak demand growth.

[18] Other drivers of electricity price growth include increased reliability standards and rising input costs. Growth in asset replacement expenditure has also contributed to higher energy prices.

3 The value of avoiding peak demand

The actual costs of meeting peak demand will vary according to the nature of demand growth, the existing network infrastructure, any constraints and overall generation capacity and mix. As noted in section 1.2, the aim of this project is to determine, at a high level, the potential value of particular initiatives to reduce peak demand in Australia.

Detailed market modelling is beyond the scope of this project, however, developing a 'rule of thumb' estimate of the cost of an additional MW of demand is an appropriate approach that has been applied in similar analyses of the electricity industry.[19] We note that substantial research on determining a methodology for valuing demand management to avoid network costs is being developed by the Institute for Sustainable Futures as part of the Commonwealth Scientific and Industrial Research Organisation's (CSIRO) Intelligent Grid Research Program.[20]

In order to develop a high level range of estimates of the value of avoided maximum demand, we have reviewed published reports, research and analysis of the costs of serving maximum demand, for both electricity networks and generators.

A number of high level estimates of the cost of meeting peak demand have been published in recent years for a variety of purposes, including by Deloitte in analysing the costs and benefits of the Advanced Metering Infrastructure Program in Victoria.[21] Some estimates have been developed based on the forecast costs and maximum demand forecasts proposed by network businesses in their regulatory submissions. For example, Energex has estimated that the average investment for each MW of additional capacity is $3.5 million, comprising of $2 million for distribution network assets, $0.7 million for transmission assets and $0.8 million for generation costs.[22] The Institute for Sustainable Futures has previously estimated incremental avoided network costs in NSW to be approximately $4 million per MW.[23]

In developing a high level estimate of the value of avoiding peak demand, the following factors have been taken into account:

- Investment is driven by load at diverse sections of a network, and accordingly, reducing coincident peak demand will not result in avoided investment at every point of constraint on the network
- Investment in network infrastructure is 'lumpy', and planning for investment is needed several years prior to peak demand exceeding capacity. Lowering peak demand may not result in an immediate deferral of investment, rather a long term response.

Some published high level estimates of the value of avoiding peak demand are summarised in the following table.

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[19] For example: Ernst & Young, AEMC Power of Choice - Rationale and drivers for DSP in the electricity market - demand and supply of electricity, December 2011.

[20] Langham, E. Dunstan, C. and Mohr, S. (2011). Mapping Network Opportunities for Decentralised Energy: The Dynamic Avoidable Network Cost Evaluation (DANCE) Model, iGrid Working Paper 4.4, Prepared by the Institute for Sustainable Futures, University of Technology Sydney as part of the CSIRO Intelligent Grid Research Program.

[21] Deloitte, Department of Treasury and Finance – Advanced Metering Infrastructure cost benefit analysis – Final Report, August 2011.

[22] Department of Employment, Economic Development and Innovation, Queensland Energy Management Plan, May 2011, p. 4.

[23] Institute for Sustainable Futures, Close to Home: Potential Benefits of Decentralised Energy for NSW Electricity Consumers – Prepared for the City of Sydney, November 2010, p. 18.

Table 13: High level estimates of the value of avoiding peak demand

Source	Estimated costs
Deloitte – network and peaking generation	$200 per kW per annum
Oakley Greenwood – Review of AMI Benefits, July 2010 – network and peaking generation	$200 per kW per annum
CSIRO – Electric Driveway Project – SP AusNet network value, using the DANCE methodology	$223 per kVA per annum
CRA 2008 – MCE Cost Benefit Analysis of Smart Meters – network only	$98 to $124 per kVA per annum
Ernst & Young – Power of Choice Review – Benchmark range – network only	$90 to $300 per kVA per annum

Sources: Deloitte, Department of Treasury and Finance – Advanced Metering Infrastructure Cost Benefit Analysis, August 2011, p. 63; Oakley Greenwood, Review of AMI Benefits – for the Department of Primary Industries Victoria, July 2010; CSIRO Electric Driveway Project, Plugging In: A technical and institutional assessment of Electric Vehicles and the Grid in Australia, Phase 1 Report, June 2011; Institute for Sustainable Futures, Close to Home: Potential benefits of Decentralised Energy for NSW Electricity Consumers, November 2010; Ernst & Young, AEMC Power of Choice - Rationale and drivers for DSP in the electricity market - demand and supply of electricity, December 2011.

The following sections discuss some more detailed estimates of network and generation costs for meeting peak demand.

3.1 Network costs

Electricity network costs represent a high proportion of the costs of meeting peak demand. When developing their network prices for different customer classes, which are to be reviewed and approved by the AER each year, distributors in the NEM are required to take into account the long run marginal cost (LRMC) of providing services.[24] Ensuring that tariffs reflect the LRMC of supply helps to send an efficient pricing signal to customers regarding the costs of their demand for electricity.

We consider that LRMC is a good measure of the additional cost a network business would incur to meet growth in peak demand, and by association, a reasonable high level estimate of the value of avoiding peak demand. There are many different methodologies for estimating the LRMC of network electricity supply and many reasons why distribution networks in different regions of the NEM have developed different estimates of LRMC, including design standards and other network characteristics.

However, we have been unable to find published high level network-wide LRMC estimates for transmission networks. We suspect this is due to the large one-off and load-specific nature of transmission investments which makes any high level average estimates of cost inappropriate for our purposes.

Given our aim is to develop a high level estimate of the value of reducing peak demand, we have reviewed a range of publicly available distribution network LRMC estimates developed by distributors for their most recent pricing proposals, without reviewing the methodologies applied in the calculations of these estimates.

The following table presents the LRMC estimates of the distributors.

[24] National Electricity Rules, clause 6.18.5 (b)(1).

Table 14: LRMC estimates published by NEM distributors

Distributor	LV ($/KVA/annum)	HV ($/KVA/annum)
Ausgrid	138.80	79.60
Endeavour Energy	331.14	83.48
ActewAGL	134.67	113.91
Jemena Electricity Networks*	160.53	44.64
United Energy Distribution*	142.44	64.65
ETSA Utilities	144.00	94.00
Average	**175.26**	**80.05**
Average excluding Endeavour Energy	**144.09**	**79.36**

Note: *Where LRMC data was presented in c/kWh, we have converted to $/kVA/annum based on industry standard load factors.

Sources: Ausgrid Network Pricing Proposal - for the FY ending June 2012 - p. 46; Endeavour Energy - Direct Control Services - Annual Pricing Proposal 2011-12, p. 79; Actew AGL, May 2011, p.17; CitiPower, 2011 Pricing Proposal, p. 38; Powercor, 2011 Pricing Proposal, p. 40; JEN, JEN Pricing Proposal 2011 Pricing Proposal, p.26; United Energy, UED Pricing Proposal 2011, table 6.3; ETSA, Pricing Proposal Appendix E.

In making an assessment of the value of deferring peak demand for distribution networks, we have relied primarily on the LV LRMC estimates, as these reflect the cost of supply for small customers. We have considered the estimate published by Endeavour Energy is an outlier, given the recent estimates published by other distributors.

3.2 Generation costs

Peaking generation in Australia is generally supplied by Open Cycle Gas Turbine (OCGT) plants. Accordingly, we have reviewed estimates of the LRMC of OCGT generation in considering the cost of meeting peak demand.

In 2010 and 2011, AEMO published its first National Transmission Network Development Plans (NTNDP) which provides a strategic long term outlook of planning and developments in the NEM. AEMO is currently consulting on the 2012 NTNDP forecasts.

Since 2009, AEMO has contracted a number of consultants to develop LRMC forecasts for different generation technologies, which take into account the relative upfront capital, ongoing maintenance and fuel costs. [25] As for network infrastructure, we consider that taking a discounted LRMC of OCGT generation plants is a reasonable proxy for the value of avoided peaking generation capacity.

In 2010, the Department of Energy Resources and Tourism (DRET) commissioned the Electric Power Research Institute (EPRI) to assess the costs of electricity generation for the purposes of developing various energy policies.[26] Estimates of LRMC based on cost assumptions produced by ACIL Tasman and Worley Parsons for AEMO and EPRI for DRET are presented in the table below.

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[25] ACIL Tasman - Fuel Resource, new entry and generation costs in the NEM, April 2009; Worley Parsons, Cost of construction New Generation Technology, January 2012.

[26] EPRI, Australian Electricity Generation Technology Costs - Reference Case 2010, February 2010.

Table 15: Estimates of LRMC for OCGT

Source	LRMC OCGT ($/kW/p.a)
EPRI, 2010	155.9
ACIL for NEMMCO (AEMO) 2009	135.9
Worley Parsons for AEMO 2011	129.2

Note: The $/kW/p.a. LRMC figures are calculated by Deloitte based on the published capital cost, fixed and variable O&M, fuel and heat rate estimates.

Sources: EPRI, Australian Electricity Generation Technology Costs - Reference Case 2010, February 2010; ACIL Tasman - Fuel Resource, new entry and generation costs in the NEM, April 2009; Worley Parsons, Cost of construction New Generation Technology, January 2012.

3.3 Conclusion – value per kW of demand

After reviewing the range of high level and detailed LRMC cost estimates discussed above, and the underlying assumptions and input data relied on in these sources, we have developed an estimate of the average cost to provide an incremental kW of peak demand in Australia, in terms of network and generation costs. We consider our estimate is a reasonable proxy for the value of avoided costs for the purposes of this high level analysis, which takes into account a number of factors relevant to the initiatives under analysis.

While we have reviewed LRMC cost estimates in forming our view on this estimate, the value of avoiding peak demand will be lower than the cost to serve peak demand, due to diversity on the network, investment profiles and the variable supply demand balance. In addition, in order to defer investment, network operators, generators and retailers need to be willing to rely on the demand reduction occurring at times of peak, considering the implications of not having the capacity or not being contracted to meet peak demand.

Traditionally, demand side participation is valued based on firm contracts between demand side providers (typically large customers) and market participants. However, most of the demand reductions associated with initiatives discussed in this paper (such as Dynamic Pricing) will not be underpinned by contracts requiring firm demand reductions. Rather, they will be based on incentives for residential customers to change their behaviour at times of peak demand. Given this relies on assumptions about the elasticity of demand for electricity, for market participants to incorporate demand reductions into their investment planning, it is accepted that historical data reflecting reliable demand reductions due to the initiatives will be needed. This will only occur over the longer term, reducing the value of avoided investment in the 10 year timeframe for this analysis.

In addition, network diversity means that while benefits may accrue to distributors due to reduced demand within an area supplied by a single zone substation (for example, a suburb where a residential peak reduction initiative is focussed), the same benefits will be dispersed and therefore lower at transmission connection points which supply a wider area. Similarly, the time of peak demand in the wholesale electricity market does not necessarily coincide with times of network peak, meaning that benefits may not accrue to all sections of the supply chain at once.

To capture all of these factors in detail, a comprehensive model of network and generation demand, supply and diversity factors would be needed, which is beyond the scope of this engagement.

Therefore, taking into consideration the stand-alone distribution network costs (between $135 and $161 per kW per annum) and generation costs ($129 to $156 per kW per annum) and the published high level ranges outlined above, we consider that an estimate of $200 per kW per annum is reasonable for the purposes of our analysis. We note that this estimate is approximately 30% below the sum of the distribution network and generation LRMC estimates, which theoretically should represent the maximum cost of supplying an additional kW of peak demand.

We note that our selected value per kW of peak demand reduction is considered appropriate for the purposes of this high level analysis, however, we would caution the use of this figure for other purposes. As we have discussed above, detailed market modelling was beyond the scope of this engagement.

Table 16: Deloitte estimate: Value of avoided peak demand

	Estimated value of peak demand ($/kW/annum)
Deloitte estimate	200

We have used this estimate in determining the potential value of the initiatives discussed in the following sections.

4 Initiatives to reduce peak demand

In recent years, supporting and encouraging measures to reduce peak demand have been a significant focus of industry and government, driven by rising investment in electricity assets to support increasing peak demand..

Household energy consumption is increasingly the major contributor to peak demand growth, as industrial and commercial loads tend to be less weather-dependent and fluctuate to a lesser extent. Accordingly, our analysis of initiatives is mostly focused on ways to reduce household summer peak demand.

Following research and consultation with the ESAA, we have selected five core initiatives for the focus of this review, including:

- Dynamic pricing – time of use and critical peak pricing and incentives
- Direct load control of air conditioning and pool pumps
- Vehicle to Grid (V2G) capability of Electric Vehicles (EVs) and Plug-in Hybrid Electric Vehicles (PHEV)
- Energy efficiency measures targeted at reducing the drivers of peak demand, including:
    - Air conditioner appliance efficiency standards
    - Improvements in building standards for retrofitting
- Small scale solar generation.[27]

Other initiatives that were researched, considered but then not evaluated include:

- Peak demand limiting, which is currently in very early trial stage in the NEM and would target a similar range of benefits as direct load control
- Residential insulation, which is captured by the improvements in building standards
- Power factor correction, which is only economic for large industrial and commercial customers and which has already been implemented to a large extent by distributors
- In home displays, for which the impact on peak demand is likely to be tied to time of use pricing and critical peak incentives. This is discussed in the section on Dynamic Pricing below
- General incentive schemes, such as the Victorian Energy Efficiency Target (VEET), for which the benefits are largely captured by energy efficiency measures
- Battery storage, which is currently uneconomic due to very high capital costs and is at early trial stage in the NEM.

The following chapters present the findings of our research and analysis on each initiative.

[27] We note that our analysis of improvements in building standards are related to savings generated by commercial customers and small scale solar savings will be delivered by both residential and commercial customers.

5 Dynamic pricing

5.1 What does it involve?

Economic theory suggests that charging customers prices that reflect the different costs of supplying electricity at different times of the day is one of the fundamental ways to reduce peak demand and ensure economically efficient consumption behaviour. Assuming consumers can receive, understand and have the freedom and ability to respond to clear, consistent price signals, and assuming that peak energy is a normal good (where demand falls as price rises), enabling flexible time of use (TOU) pricing is a very reasonable approach to managing peak demand. Where these criteria do not hold, for example, people that cannot reduce their energy use at peak times due to work requirements, the economic case for such variable pricing becomes less clear.

There are a number of different ways that flexible pricing can be undertaken, which for convenience we have grouped together as Dynamic Pricing.

For the purposes of our analysis, we have defined Dynamic Pricing as constituting the following:

- Three-rate TOU tariffs (peak, shoulder, off peak), for which rates may vary between seasons (Winter, Summer) however otherwise remain fixed for the contract period
- Critical peak pricing (CPP) and/or critical peak incentives, which involve at least one-day ahead notifications being sent to customers to advise them of a critical peak pricing event. During a critical peak pricing event, electricity prices would be significantly higher than normal TOU peak prices. Alternatively, during a critical peak pricing event, customers could earn an incentive payment by reducing their demand from a determined baseline by an agreed amount.

In most Australian states, large commercial and industrial customers have been subject to TOU pricing for some time, however, TOU pricing has not been widely available to residential customers, due to the fact that the current stock of electricity meters are not able to record consumption over different periods of the day. We note that in some jurisdictions, for approximately ten years, distributors have been installing, on a new and replacement basis, meters with multiple registers that can record consumption in peak, shoulder and off-peak periods. However, the time periods for these meters are generally predetermined at the manufacturing stage and daily consumption within periods is not recorded. Interval metering, which records consumption on a half hourly basis, is required to facilitate Dynamic Pricing.

The degree to which customers will respond to peak prices over the long term is the subject of significant research and debate, both in Australia and internationally.

Trials of Dynamic Pricing are being undertaken by distributors and retailers in Australia and in many locations worldwide. We have reviewed a sample of trial and research results in determining the potential value of Dynamic Pricing in reducing peak demand. The following table lists the trials whose results we have considered in our analysis.

Table 17: Dynamic Pricing – Australian and international trials and research

Organisation	Jurisdiction	Basis of findings / assumptions
Ausgrid – various trials since 2005	NSW	Ausgrid has been carrying out trials of Dynamic Pricing with residential customers for some years, under various programs, most recently the Smart Grid Smart City trial. Ausgrid's main published trial results are based on data collected over 2006 involving 3000 customers on TOU tariffs.[28]
Essential Energy – Home Energy Efficiency Trial (2004)	NSW	This trial involved 150 customers participating in critical peak pricing events.
Endeavour Energy – Western Sydney Pricing Trial	NSW	This involved 900 customers across a range of TOU and critical peak pricing, as well as a web interface.
CRA International – California Statewide Pricing Pilot 2005	California	Results from various Dynamic Pricing trials involving 2500 customers over 18 months in 2003-04.
Newsham and Bowker –2010	North America	This is a research paper titled *The effect of utility time-varying pricing and load control strategies on residential summer peak electricity use: a review*. The analysis stems from the results of 16 studies on Dynamic Pricing carried out by utilities across North America.
The Brattle Group – various studies, reports and presentations	USA	Based on rate designs in the US and trial results.
Deloitte – Cost benefit analysis of the Victorian Advanced Metering Infrastructure Program, August 2011	Victoria	Assumptions and analysis based on a range of international trial results on TOU and Critical Peak pricing incentives.
MCE – Cost benefit analysis of smart meters and direct load control, 2008	Australian states	Assumptions and analysis on customer response to TOU and critical peak pricing was based on the findings from the California Statewide Pricing Pilot.
OTTER – Cost benefit analysis of the rollout of interval meters in Tasmania, 2006	Tasmania	Assumptions based on a range of Australian and international trial results on TOU pricing.

Sources: Futura Consulting, Power of choice – giving consumers options in the way they use electricity - Investigation of existing and plausible future demand side participation in the electricity market, Final Report, December 2011 (reporting results of Ausgrid, Endeavour Energy and Essential Energy); CRA International, Impact Evaluation of the California Statewide Pricing Pilot, March 2005; Newsham and Bowker, The effect of utility time-varying pricing and load control strategies on residential summer peak electricity use: A review, June 2010; Faruqui, Dynamic Pricing: The top 10 Myths - ENA Smart Networks Summit, Sydney May 2011; Deloitte, Department of Treasury and Finance - Advanced metering infrastructure Cost benefit analysis, August 2011; NERA et al for the MCE, Cost Benefit Analysis of Smart Metering and Direct Load Control - Overview Report for Consultation, February 2008; OTTER, Costs and Benefits of the Rollout of Interval Meters in Tasmania - Final Report, October 2006.

[28] Futura Consulting, Power of choice – giving consumers options in the way they use electricity - Investigation of existing and plausible future demand side participation in the electricity market, Final Report, December 2011;

5.2 What is needed to achieve the benefits?

As discussed above, the primary piece of infrastructure required to implement Dynamic Pricing is interval meters which are capable of recording electricity consumption in short intervals, most commonly half hourly periods.

In some States, interval meters are being rolled out with significant communications infrastructure ('smart meters') to enable them to transmit consumption and connection point data to the distributor every half hour. The ability to remotely communicate with meters presents a large number of potential benefits for distributors and customers, in particular more efficient network management. Accordingly, the economic case for installing smart meters typically relies on a multitude of benefits that include many which are unrelated to Dynamic Pricing.

We recognise that some aspects of Dynamic Pricing can be implemented without remote communications to the meter. However, based on our research, it is clear that the benefits of TOU pricing and critical peak pricing or incentives are closely tied to providing enhanced information on energy consumption to customers. Real time (or close to real time) feedback on energy use is seen as an important driver of customer behaviour, as being able to review and understand what is behind electricity bills within short intervals (not necessarily instantly, however much more frequent than the common quarterly bill cycle) will significantly enhance customer willingness and ability to respond to Dynamic Pricing.

In our view, experience in Victoria and other international jurisdictions suggests that it is unlikely that TOU pricing will be rolled out on a mandatory basis. In order to attract a critical mass of customers to Dynamic Pricing, information and feedback on energy use will be needed to ensure that customers are best placed to benefit and therefore commit to Dynamic Pricing on a large scale.

In order to develop an understanding of the range of costs involved in implementing Dynamic Pricing, we have reviewed the costs per customer incurred or expected to be incurred in smart meter rollouts in Australia and internationally. As to be expected, rollout costs vary substantially, driven by economies of scale and quantity discounting as well as vast functionality and technology differences. With rollouts in the range of 280,000 to 35 million meters, reported costs per customer range from $170 to over $900.[29]

We have also reviewed estimates of costs developed by EMCa for the MCE in 2008 as part of the National Cost Benefit Analysis of Smart Metering and Direct Load Control.[30] This is the only comprehensive Australia-wide study on the expected costs of a mandatory rollout of smart metering that has been conducted to date. The range of costs per customer in each state was estimated by EMCa at $341 to $475, or $377 per customer, as an Australia-wide average.

Noting the variance between actual rollout costs and estimates discussed above, we acknowledge that there are a large number of variations that prevent an accurate comparison between international and Australian smart meter rollouts, including:

- Numbers of meters installed
- Type of meter installed
- When and how the meter is installed (on a voluntary (customer request) basis, new and replacement, or a mass rollout)
- Communications infrastructure that is suitable for the region

[29] Rollouts considered were in Victoria, France and Western Australia. See: Deloitte, Department of Treasury and Finance - Advanced metering infrastructure Cost benefit analysis, August 2011; eMeter Smart Grid Watch article – French Government Announces Smart Meter Rollout Schedule, September 29 2011 – Accessed at: http://www.emeter.com/smart-grid-watch/2011/french-government-announces-smart-meter-rollout-schedule/ Accessed on 29 February 2012; Western Power, Smart Grid Proposal, October 2011.

[30] EMCa, Cost Benefit Analysis of Smart Metering and Direct Load Control - Workstream 6: Transitional Implementation Costs: Phase 2 Consultation Report, February 2008.

- Associated back office and IT costs, for both distributors and retailers.

5.3 What is the potential impact on peak demand?

5.3.1 Potential customer response to TOU and CPP at peak times

The results of trials and research discussed above and listed in table 17 are presented in the following tables.

Table 18: TOU Pricing –Results of studies and trials

Source	Peak demand reduction achieved (% per customer peak demand)
Ausgrid – AMI Trial 2006 and Strategic Pricing Study 2005	4% to 13%
Endeavour Energy – Western Sydney Pricing Trial	No quantifiable result
CRA International – California Statewide Pricing Pilot 2005	0.6% to 5.9%
Newsham and Bowker, various North American trials and studies, 2010	-4% to +5%*
The Brattle Group – various papers and presentations	14% to 18% (median)
Deloitte 2011 – Cost Benefit Analysis of AMI	1.5%
MCE – Cost benefit analysis of Smart Metering and Direct Load Control (estimates for all states)	1.1% to 5.8%
OTTER 2006 – Accelerated smart meter rollout (Scenario 9)	10%

* Note: Newsham and Bowker reported much higher peak demand reductions achieved in some of the TOU studies they reviewed (up to 30%), however the higher results were generally from studies involving other enabling technologies (such as direct load control) in addition to simple TOU pricing. The negative low end result represents an increase in peak time usage reported as a result from a 2006 Idaho trial. Newsham and Bowker stated that a simple TOU program can only expect to realise on-peak reductions of 5%. See: Newsham and Bowker, The effect of utility time-varying pricing and load control strategies on residential summer peak electricity use: A review, June 2010.

Table 19: CPP Incentives– Results of studies and trials

Source	Peak demand reduction achieved (% per customer peak demand)
Ausgrid –Strategic Pricing Study 2005	36%
Endeavour Energy – Western Sydney Pricing Trial	35%
Essential Energy – Home Energy Efficiency Trial	25%
CRA International – California Statewide Pricing Pilot 2005	13.1% to 27.2%
Newsham and Bowker, 2010	4% to 40% - CPP 0 to 18% - Peak time rebate
The Brattle Group – various studies, reports & presentations	34% to 38% (median)
Deloitte 2011 – Cost Benefit Analysis of AMI	15%
MCE – Cost benefit analysis of Smart Metering and DLC	10.6% to 21.5%

The range of Australian time of use studies and trial results in table 19 spans from 1.1% to 13% peak load reduction, while the range of results of international trials and studies spans from -4% to 18%. There is considerable debate about the potential load reductions that can be achieved by time of use pricing in Australia. Results are undoubtedly affected by the sample or trial size, the price differential between peak and off peak periods and the time period over which the tariffs are in place.

The potential peak load reductions achieved by critical peak pricing trials and studies are significantly greater than those for time of use pricing, ranging between 10.6% and 36% in Australia and 4 to 40% internationally. Results will vary depending on the price differential and how many times per year critical peak events are notified.

The impact of fatigue over time as customers adjust to new pricing regimes is not yet fully understood. In addition, we note that in order to avoid network costs, peak load reductions need to be firm and sustainable such that distributors can justifiably rely on them in risking adverse service standards outcomes. In practice, this is likely to occur only over the long term as a reliable data set on customer response to Dynamic Pricing is obtained.

Accordingly, in estimating the peak load reductions that could be achieved and relied upon by networks and generators over the next decade, a conservative lens needs to be applied to the results listed above.

Based on our experience and research, we have selected the following high and low estimates of customer responses to Dynamic Pricing in calculating the range of possible benefits.

Table 20: Dynamic Pricing – Deloitte peak load reduction assumptions

Dynamic pricing	Low estimate (% response)	High estimate (% response)
Time of use tariffs	1.5%	5%
Critical peak pricing or incentives	10%	33%

We acknowledge that there are differences in the assumptions and circumstances surrounding the research and trials we have reviewed which would affect the potential reductions in peak demand that can be achieved. For example, trials which involve incentive payments to participants are recognised to suffer from selection bias, whereby the trial may produce outcomes that are more favourable than would be the case should the tariffs be implemented on a business as usual basis.

However, given the objective of our review is to develop a plausible range of benefits, we consider the application of this high level analysis of results is appropriate.

In developing these estimates of high and low benefits from Dynamic Pricing, we have not determined an average TOU price nor the differential between the three time periods, noting that this in itself would require a significant number of assumptions about likely DNSP and retailer pricing. Instead, we have reviewed the literature and considered the average impact of TOU pricing on peak demand.

Rather than specifying a particular design or pricing structure for critical peak pricing and incentives, we have reviewed the literature and considered the potential peak load reduction that a variety of critical peak prices and incentive payments could deliver.

We have also assumed that in order to achieve the benefits of TOU pricing, some information is provided to customers to support their response to the new tariffs, including in home displays (IHDs) or enhanced billing. We note that there is significant literature in support of the energy efficiency benefits associated with IHDs and enhanced billing, however, it is difficult to isolate the impact of these on peak demand from Dynamic Pricing.

5.3.2 Potential reductions in peak demand – other assumptions

Taking the range of estimates of customer response to Dynamic Pricing discussed in the previous section, we have then made the following assumptions to determine the potential value of this initiative:

- Take up rates – In order to estimate a benefit, we have assumed that a maximum of 15% of customers elect to partake in TOU tariffs, gradually increasing from 2012 to 2018. This assumption recognises that even with a strong Government led mandate for this initiative, smart meter installations are likely to be at various stages across the NEM over the next decade. Our conservative assumption reflects a reasonably achievable benefit in the medium term.
- Average peak load per customer – we have used an average customer peak load of 3kW in estimating the potential peak load reductions achievable.

The engagement of customers in Dynamic Pricing is key to achieving the take up rates that are assumed in this study. International evidence of the value of engaging customers early in any smart meter rollout and pricing program, and building their trust through educational materials and information on time of use pricing, is mounting.

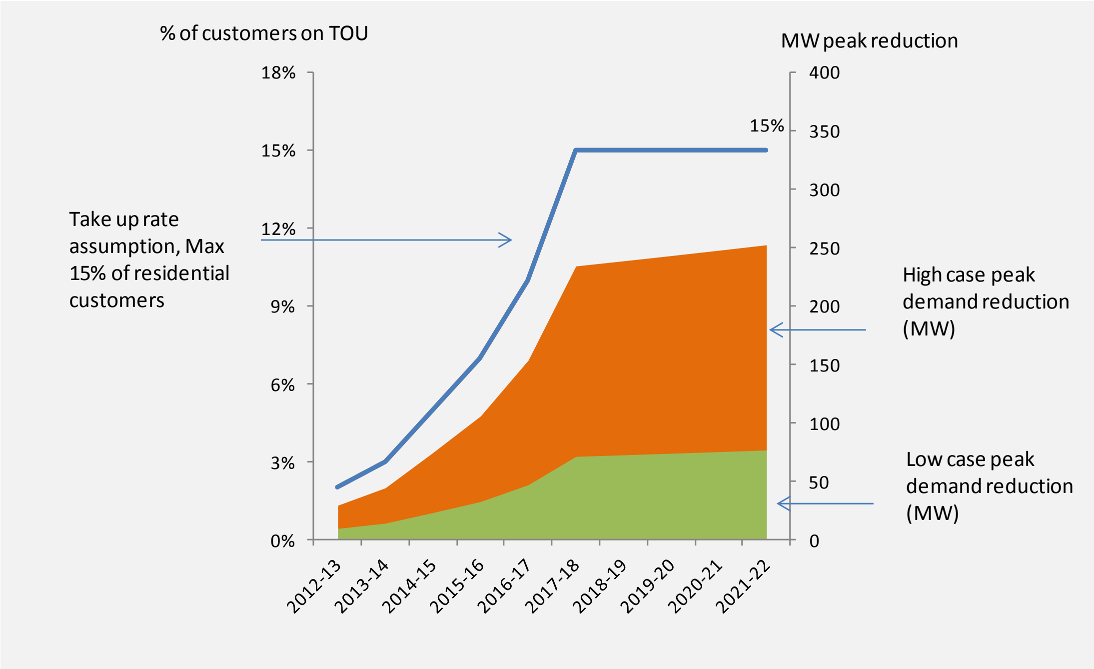
Canadian utility HydroOne undertook an extensive customer engagement program throughout its smart meter installation program over 2004 to 2011, with each customer receiving 3 to 5 individual communications regarding the objectives, benefits and implications of time of use pricing and smart metering. HydroOne is now in the final phases of switching all of its 1.2 million residential and small business customers to time of use pricing. With a 100% take up rate and relatively little customer opposition to the new tariff structures, HydroOne and its customers are set to achieve significant peak load reduction benefits due to Dynamic Pricing initiatives.[31]

In order to achieve the benefits associated with Dynamic Pricing discussed in this report, clear, consistent and sustained communications from industry and Government on the implications, costs and benefits of Dynamic Pricing is crucial.

The following graphs represent our assumptions regarding take up rates and potential peak load reduction (MW – high and low case scenarios) for time of use tariffs and critical peak pricing and incentives.

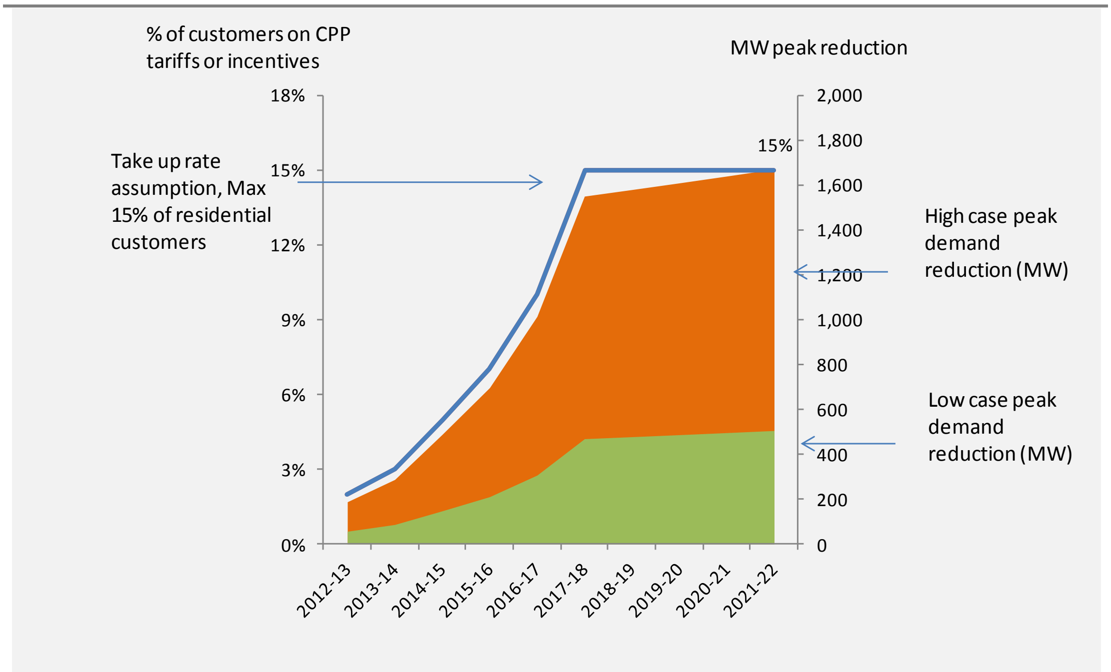
[31] Deloitte, Department of Treasury and Finance - Advanced metering infrastructure Cost benefit analysis, August 2011, pp. 37-38 and HydroOne website, available at: http://www.hydroone.com/TOU/Pages/Default.aspx Accessed 2 March 2012.

Figure 8: Time of use tariffs – take up rate and potential peak load reduction



Source: Deloitte analysis

Figure 9: Critical peak pricing tariffs and incentives – take up rate and potential peak load reduction



Source: Deloitte analysis

5.4 Conclusion – value of potential benefits

In conclusion, we consider that the implementation of Dynamic Pricing across the NEM and SWIS over 2012 to 2022 offers benefits in the range set out in the table below.

Table 21: Dynamic Pricing – estimated value of benefits 2012-13 to 2021-22 (NPV, $m)

	Low case estimate ($m)	High case estimate ($m)
Time of use pricing	58	193
Critical peak pricing / incentives	385	1,272

Source: Deloitte analysis

6 Direct load control

6.1 What does it involve?

Direct load control has been used by electricity distributors to control residential electric storage hot water systems across Australia for over 30 years. Load control devices (or time clocks) enable distributors to stagger hot water load throughout neighbourhoods to prevent it from contributing to peak demand. Prior to this technology, hot water demand was one of the major drivers of peak demand, which as discussed above, historically occurred during the winter in most parts of Australia. The savings generated by direct load control of hot water systems are substantial – Energex alone estimates that it has saved 450 MW of winter peak demand.[32] In analysis conducted for the AEMC in December 2011, Futura estimated that 1,750 MW of summer peak demand has been shifted to off-peak periods Australia-wide through the use of direct load control of hot water systems.[33]

It is not surprising, therefore, that direct load control of air conditioning and pool pumps – two of the major drivers of peak demand in Australia over the past decade – is now being trialled by distributors across the country. Direct load control devices installed in air conditioning enable distributors to remotely cycle compressors over short intervals to manage the collective load on the network and reduce peak demand. A well-managed direct load control program means that participating customers are unaware of the impact of the load control on their cooling.

Internationally, direct load control has extended beyond air conditioning and pool pumps to other appliances. Californian distributor, Florida Power & Light, operates a program called *On-Call* which is viewed as one of the most successful load control programs in the US. Controls are fitted to five or more appliances in each eligible customer's home in return for a fixed annual rebate of up to US$137 per year.[34] At times of peak demand, Florida Power & Light selectively controls appliances such that customers are unaware of the impact. This direct load control program has provided Florida Power & Light with control over 10% of its peak load (2,500 MW).[35]

The best-known and most extensive Australian trials of direct load control of air conditioning to date have been conducted by ETSA Utilities and Energex.

Since 2006, ETSA Utilities has conducted several direct load control trials targeting residential and commercial volunteer customers' air conditioning. Results of these trials indicated that the potential reduction in each customer's peak load ranges from 19% to 35%.[36]

However, findings from ETSA's trials indicate that only particular types of air conditioners are able and worthwhile to be controlled. Based on the results of its trials, ETSA carried out a cost benefit analysis of a larger scale rollout of direct load control of air conditioning. Based on an assumption of 10% customer take up, ETSA found that a large scale rollout of direct load control in its territory would not result in net benefits. However, results of a cost benefit analysis of an enhanced load control device (known as Peakbreaker+), which is fitted with two-way communications and provides enhanced network optimisation, concluded with positive net benefits.[37]

[32] Energex, Response to the Prime Minister's Task Force on Energy Efficiency, April 2010. We note that there are still further potential savings to be delivered by increased penetration of direct load control of hot water systems, particularly in jurisdictions which currently have a lower take up. However, we have not attempted to measure the further potential for peak demand savings from controlling hot water, focussing instead on new initiatives to lower peak demand.
[33] Futura Consulting, Power of choice – giving consumers options in the way they use electricity - Investigation of existing and plausible future demand side participation in the electricity market, Final Report, December 2011.
[34] Florida Power & Light, website link: http://www.fpl.com/residential/savings/onrecall.shtml , Accessed 23/2/12, 2:30pm.
[35] Deloitte, Department of Treasury and Finance – Advanced Metering Infrastructure cost benefit analysis – Final Report, August 2011.
[36] ETSA Utilities, Project EPR 0022 – Response to AEMC Issues Paper – Power of Choice, September 2011.
[37] ETSA Utilities, Demand Management Program Interim Report No. 3, June 2010.

Energex's Cool Change Trial, which commenced in the summer of 2007 and is still in operation, involves trialling direct load control of over 2,000 customers' air conditioners. On average, customers involved reduced their demand by 13% over the 2009-10 summer peak.[38]

Other trials of direct load control are being carried out as part of the Australian Government's Solar Cities Program, in particular in Perth and Blacktown. The Blacktown Solar Cities air conditioner trial, which involved distributor Endeavour Energy cycling 529 customers' air conditioners, achieved a 27% reduction in their peak load.[39] In its first year, the Perth Solar Cities air conditioner trial achieved an average reduction of up to 20% of the peak demand of 211 participant households.[40]

Trials of direct load control of pool pumps have also been carried out in Australia, and even implemented as business-as-usual tariffs in Queensland by Energex and Ergon Energy and in NSW by Endeavour Energy. Two trials of pool pumps implemented by Energex achieved average peak load reductions of 0.8 kW per appliance (or 27% of average customer peak load of 3 kW).

Energex is currently offering customers a $250 gift card in exchange for connecting their pool pumps to an off-peak controlled load circuit (tariff 33 or tariff 31), which offers a lower c/kWh rate in exchange for periods of no supply during peak.[41] Futura has estimated that 110 MW of pool pump load has already been shifted away from the peak period in South East Queensland.[42]

In 2009, as part of the Blacktown Solar Cities program, Endeavour Energy implemented a pool pump direct load control trial which it subsequently expanded to offer its customers on a commercial basis. Endeavour Energy's pool pump load control trial achieved average reductions of up to 36% of peak demand per customer.[43] The quantity of pool pump peak load that has already been shifted in Endeavour Energy's region as a result of new direct load control tariffs is not reported.

The following tables outline the results of our research on the potential impact of direct load control of air conditioning and pool pumps.

Table 22: Direct load control of air conditioners – research and trials

Organisation	Jurisdiction	Peak load reduction per customer (%)	Basis of findings / assumptions
ETSA Utilities	South Australia	19 to 35%	Various trials since 2006 – air conditioning
Energex	SE Queensland	13%	Trials
Blacktown Solar Cities	Western Sydney	27%	Trials
Perth Solar Cities	Perth	20%	Trial in 2010-11, 211 customers
Deloitte – Cost benefit analysis of the Victorian AMI Program, August 2011	Victoria	15%	Assumptions & analysis based on a range of international trial results on direct load control
MCE – Cost benefit analysis of Smart Metering and DLC	Australia	11.7% to 13.9%	Assumptions and analysis based on a range of trial results

[38] Energex, Time for a cool change – Energy Smart Suburbs – Newsletter November 2010.
[39] Futura Consulting, Power of choice – giving consumers options in the way they use electricity - Investigation of existing and plausible future demand side participation in the electricity market, Final Report, December 2011, p. 60.
[40] Perth Solar City Annual Report 2010-11.
[41] Energex website, http://www.energex.com.au/sustainability/energy-conservation-and-demand-management/residential-targeted-initiatives/pool-rewards-program , Accessed 24 February 2012.
[42] Futura Consulting, Power of choice – giving consumers options in the way they use electricity - Investigation of existing and plausible future demand side participation in the electricity market, Final Report, December 2011.
[43] Futura Consulting, Power of choice – giving consumers options in the way they use electricity - Investigation of existing and plausible future demand side participation in the electricity market, Final Report, December 2011, p. 65.

Table 23: Direct load control of Pool pumps – research and trials

Organisation	Jurisdiction	Peak load reduction per customer (%)	Basis of findings / assumptions
Energex	SE Queensland	27%	Trials
Endeavour Energy - Blacktown Solar Cities	Western Sydney	36%	Trials

6.2 What is needed to achieve the benefits?

A range of load control devices have been used in Australian trials, which vary according to the type of air conditioner on which it is installed. Where customers do not have a smart meter, load is typically either controlled via a ripple control system or FM radio signals between the distributor and air conditioner. Ripple control systems are relatively widespread in NSW and Queensland, however are less prevalent in the other states.[44]

Customers with a smart meter still require a device to be fitted to their air conditioner, however, load is controlled via a Home Area Network or equivalent, through the smart meter.

A significant amount of work has been undertaken by the Equipment Energy Efficiency Committee and the National Smart Metering Program in developing standards for load control features within priority appliances, including developing minimum demand control functionality and standards for connection to load control interfaces. Local manufacturers have begun to incorporate Australian Standard AS4755 interface into their air conditioners, which provides standards for a simple interface that enables load control. Similar standards are being developed for pool pumps.[45] Smart air conditioners, which are pre-fitted with Peak Smart technology at the time of manufacture, are already appearing on the Australian market, for example, various models are produced by Kelvinator.[46]

The costs of installing a load control device in an existing air conditioner, including the device itself and the time taken to install it, vary according to the type of air conditioner and control system. As part of the MCE's 2008 Cost Benefit Analysis of Smart Metering and Direct Load Control, EMCa reviewed the costs of suitable direct load control devices available on the market.[47] Costs of retrofitting old air conditioners were estimated to range between $160 to $280 (total installation cost), while costs of fitting devices in new air conditioners at the same time as they are installed was estimated to range between $120 to $190.[48]

We have reviewed the cost estimates used by EMCa in light of more recent developments and trials, to develop an average range of likely costs incurred in direct load control of air conditioners and pool pumps. We note that the costs of implementing device trials are generally higher than would be expected on a business as usual basis, and accordingly there is limited information available on the likely costs of a commercial scale rollout.

[44] EMCa, Cost Benefit Analysis of Smart Metering and Direct Load Control - Workstream 6: Transitional Implementation Costs: Phase 2 Consultation Report, February 2008.

[45] National Smart Metering Program Business Requirements Working Group, The National Smart Metering Program and the AS4755 Appliance Interface: Establishing a Direct Connection.

[46] Current.com.au, Kelvinator brings Peak Smart air con technology to the community, 16 January 2012, accessed at: http://www.current.com.au/2012/01/16/article/Kelvinator-brings-Peak-Smart-air-con-technology-to-the-community/PDWKYTBPWM.html . Accessed on 24 February 2012.

[47] EMCa, Cost Benefit Analysis of Smart Metering and Direct Load Control - Workstream 6: Transitional Implementation Costs: Phase 2 Consultation Report, February 2008.

[48] NERA et al, Cost Benefit Analysis of Smart Metering and Direct Load Control - Overview Report for Consultation, February 2008, p. 41 to 42.

We reviewed a presentation on low cost direct load control made by David Crossley of Energy Futures Australia at a Metering and Billing conference in Brisbane, November 2006. [49] Crossley reported on a range of potential devices and associated communications equipment that would allow air conditioner or other appliance cycling. Costs vary significantly depending on the method of communication (wired or wireless, one way or two way to allow load measurement), whether there is an information display for reporting to customers and whether interval measurement of load is required. Costs were reported by Crossley to be as low as $26 per installed device (for example, for a plug in device that enables remote control of appliances through power line signalling) up to $600 for a fully integrated load control system.[50]

Our range of total costs per customer estimates reflect the costs incurred in international trials and actual market offerings, allowing a conservative maximum cost to cover potential complications in the installation of the device.[51] We have presumed that the devices to be installed are not associated with a time of use load control plan, and for simplicity, that the range also covers the costs of installing devices where there is a smart meter installed.

The following table presents our estimates of the range of costs per device.

Table 24: Direct load control – ranges of costs ($2012)

Device	Total cost per customer – Low case	Total cost per customer – High case
Retrofitting existing AC	150	280
New AC, installed at time of AC installation	100	190
Pool pump DLC device	120	235

Source: Deloitte analysis

Our estimate of total costs associated with implementing direct load control of air conditioning and pool pumps, based on the take up rates discussed below, is presented in the following table.

Table 25: Direct load control – total costs

	Costs – Low case ($m)	Costs – High case ($m)
Direct load control of air conditioners	55	262
Direct load control of pool pumps	23	51

Source: Deloitte analysis

[49] Crossley, Energy Futures Australia Pty Ltd - Presentation to Metering & Billing/CRM Conference: Low Cost Load Control Technology, November 2006
[50] Crossley, Energy Futures Australia Pty Ltd - Presentation to Metering & Billing/CRM Conference: Low Cost Load Control Technology, November 2006, p. 29.
[51] Deloitte, Department of Treasury and Finance – Advanced Metering Infrastructure cost benefit analysis – Final Report, August 2011

6.3 What is the potential impact on peak demand?

Table 22 above outlines the range of peak load reductions that have been achieved in various Australian trials, as well as the assumed peak load reductions derived in two cost benefit analysis studies of direct load control. After reviewing the ranges of achievable reductions in published trials, we have applied the peak load reduction assumptions as set out in the table below.

Table 26: Direct load control – Peak reductions per customer

	Peak reductions per customer - Low case (% per average customer peak load)	Peak reductions per customer - High case (% per average customer peak load)
Direct load control of air conditioners	11.7%	35.0%
Direct load control of pool pumps	27.0%	36.0%

Both the size of a customer's peak load and the contribution of an air conditioner to that customer's peak load can vary significantly, depending on house size, type of air conditioner and the number and type of other appliances that are installed at the house. We recognise that more detailed modelling of average customer loads in different States and regions would produce a more accurate estimate of the potential impact of direct load control on total summer peak demand. However, such detailed modelling is beyond the scope of this analysis. For the purposes of estimating the value of load control, we have used a base assumption of average customer contribution to peak of 3 kW, to which we've applied the range of trial results discussed above.

In order to estimate a take up rate of direct load control to determine the potential value in terms of avoided infrastructure investment, we have considered the approach taken in the MCE's National Cost Benefit Analysis of Smart Metering and Direct Load Control, as well as the take up rates assumed in Deloitte's Cost Benefit Analysis of the Victorian AMI Program.

Estimates of air conditioner penetration and pool pump ownership are presented in table 26. We note that air conditioner penetration rates are presented as those net of evaporative coolers (as these are not suitable for direct load control), with data sourced from the ABS and a report prepared for the National Appliance and Equipment Energy Efficiency Committee in 2006.[52]

Our forecast of pool pumps was derived from a report by Dr George Wilkenfeld for the Department of Environment, Water, Heritage and the Arts in July 2009.[53] Based on Energex's estimates of pool pumps that are already controlled under its Tariff 33 and Tariff 31 programs, extrapolated by Futura in its report to the AEMC Power of Choice Review, we have estimated the number of uncontrolled pool pumps from which peak load savings are available.[54]

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[52] ABS, 4602.0.55.001 - Environmental Issues: Energy Use and Conservation, Mar 2011; Energy Efficient Strategies, Status of Air Conditioners in Australia, January 2006.

[53] Wilkenfeld, Dr George, Swimming Pools: Energy use and impact on peak load, July 2009

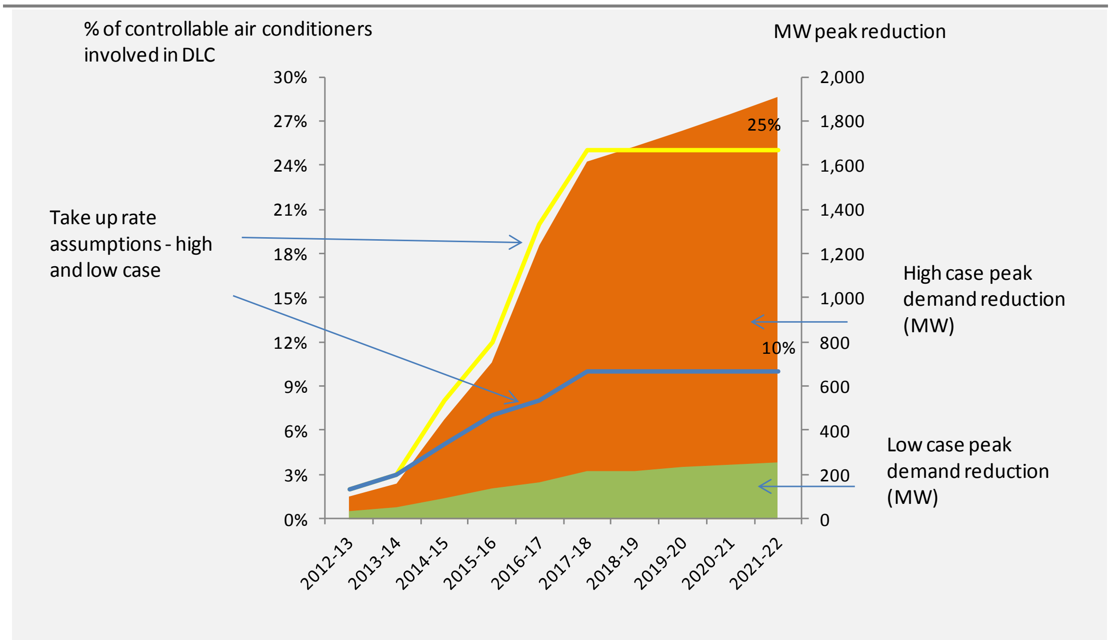
[54] We estimate that there are currently 140,000 pool pumps already involved in direct load control programs in Australia (being 10% of the current pool pump load).

Table 27: Direct load control – assumptions (Australia-wide)

Year	Air conditioner penetration – non evaporative coolers only	Uncontrolled pool pump forecast
2012-13	59.0%	1,110,000
2013-14	60.5%	1,160,000
2014-15	62.1%	1,170,000
2015-16	63.7%	1,210,000
2016-17	65.4%	1,235,000
2017-18	66.9%	1,260,000
2018-19	68.2%	1,310,000
2019-20	69.5%	1,335,000
2020-21	70.9%	1,372,281
2021-22	72.3%	1,410,504

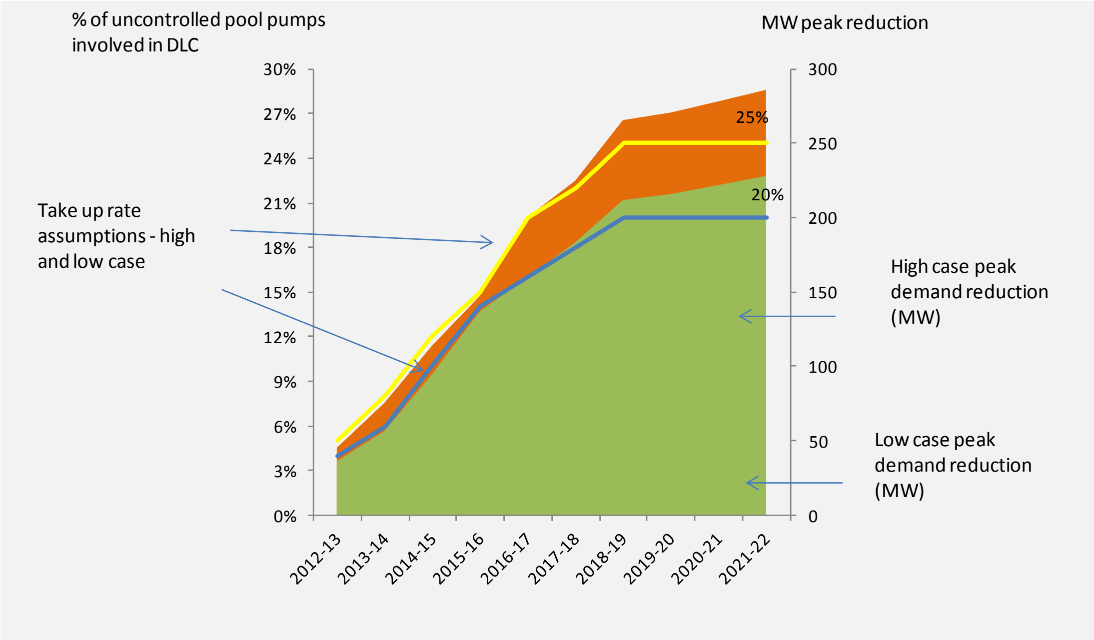
Our estimated national take up rates of direct load control, reported as a percentage of all customers, not just those with air conditioning or pool pumps, are presented below in graphs, along with our estimates of the potential peak load reductions (MW) for the high and low case scenarios.

Figure 10: Direct load control of air conditioners – take up rate and potential peak load reduction



Source: Deloitte analysis

Figure 11: Direct load control of pool pumps – take up rate and potential peak load reduction



Source: Deloitte analysis

6.4 Conclusion – value of potential benefits

In conclusion, we consider that the implementation of direct load control of air conditioning across the NEM and SWIS over 2012 to 2022 offers benefits in the range set out in the table below.

Table 28: Direct load control – estimated value of benefits 2012-13 to 2021-22 (NPV, $m)

	Low case estimate ($m)	High case estimate ($m)
Direct load control of air conditioners	200	1,338
Direct load control of pool pumps	188	231

Source: Deloitte analysis

7 Vehicle to Grid - Electric and Plug in Hybrid Electric Vehicles

7.1 What does it involve?

With concerns about climate change, fuel price rises, declines in the cost of electric vehicles (EVs) and improvements in EV travel distances, it is reasonable to expect an increase in the take up of EVs will occur in the near future. Recent Australian studies on EVs have optimistically forecast that customer take-up in Victoria will be in the order of 50% of new car sales (more than 100 000 EVs) by 2015, and a similar magnitude in NSW by 2018.[55]

While initial EV take-up involves Hybrid Electric Vehicles (HEVs), as the momentum behind EVs builds and manufacturers respond, Plug-in Hybrid Electric Vehicles (PHEVs) and Battery EVs (BEVs) will become more prevalent. These vehicles pose serious issues, but also opportunities, for electricity markets and networks which are already facing rising peak demand.

Significant uncontrolled charging of EVs would have large adverse consequences for the electricity system, in terms of increasing peak demand, as well as creating system instability. Therefore, we consider it is most likely that regulated or controlled charging of EVs will be implemented before a significant number of the vehicles are sold in Australia.

Californian utility, Pacific Gas & Electric (PG&E), has led the way encouraging its customers to adopt EVs by offering specialised EV tariffs, depending on vehicle types and charging behaviour. While PG&E has recognised the potential for Vehicle to Grid (V2G) technology and tariffs, it is not currently available to customers. [56]

Better Place Australia, a subsidiary of US firm Better Place LLC, is a high profile company that is supporting the take up of EVs in Australia through promoting its innovative battery-swap charging business model. The Better Place model enables its member EV drivers to switch a depleted battery for a fully charged one in under five minutes at a Battery Switch Station. Better Place contracts with electricity suppliers to ensure batteries are recharged using renewable energy.[57]

Many research papers on EVs highlight the potential benefits for the electricity market and system that could be generated by the widespread adoption of EVs with controlled charging. For example, the Centre for Energy and Environmental Markets at the University of NSW published a paper in 2010 on the potential for coordinated charging to improve the utilisation of network infrastructure.[58]Several other research papers suggest that EVs present an opportunity to support intermittent renewable generation with baseload storage.[59] However, to date there has been relatively little research on the V2G peak load support capability for EVs internationally, let alone in Australia.

[55] AECOM, Forecast Uptake and Economic Evaluation of Electric Vehicles in Victoria, Final Report, May 2011; AECOM, Economic Viability of Electric Vehicles - Department of Environment and Climate Change (NSW), September 2009.
[56] Pacific Gas & Electric Website, http://www.pge.com/myhome/environment/whatyoucando/electricdrivevehicles/rateoptions/ Accessed 24/2/12.
[57] Better Place website: http://www.betterplace.com.au/about-us/our-solution.html Accessed 24/12/12.
[58] Cain, MacGill and Bruce, School of Photovoltaic and Renewable Energy Engineering – Centre for Energy and Environmental Markets, Assessing the Potential Impacts of Electric Vehicles on the Electricity Distribution Network, 2010.
[59] Curtin University of Technology, Electric Vehicles and their Renewable Connection – How Australia can take part in the Green Revolution, presentation, June 2009.

A US research paper published in 2006 estimated the potential for controlled charging of PHEVs to provide peaking capacity.[60] Denholm and Short, working for the US Department of Energy, investigated the potential for PHEVs to provide support during periods of extreme peak demand or emergencies, evaluating the potential driving and charging behaviour over six geographic regions in the US. The paper presents a range of potential dependable capacity based on a number of scenarios, as outlined in the following table.

Table 29: Denholm and Short – PHEV charging capacity

Vehicle use	Effective capacity – range
% reliably plugged in at planning peak	40 – 60%
Average battery state of charge at planning peak (%)	40 – 50%
Discharge time required for dependable capacity (hours)	4 – 8 hours
Base dependable capacity (kW per PHEV)	0.2 to 0.77 kW

Source: Denholm and Short, An Evaluation of Utility System Impacts and Benefits of Optimally Dispatched Plug-In Hybrid Electric Vehicles, October 2006, p. 20.

Denholm and Short reported these findings as conservative, having attempted to capture the uncertainty that utilities may apply to generators they do not own. The paper notes that as PHEVs penetrate the vehicle market, this uncertainty should fall away.

The CSIRO and the Institute for Sustainable Futures are together undertaking a comprehensive assessment of potential EV uptake and use under Australian conditions. The Electric Driveway Project will run over three years and explore the potential synergies between the electricity and transport sectors presented by EVs. A Phase 1 Report was released in March 2011, which included an assessment of international EV developments and the potential vehicles for the Australian market. Forecasts of EVs were drawn from AECOM's studies on take up in Victoria and NSW.[61]

Using analysis of Victorian Net System Load Profile data and SP AusNet's planned growth-related network investment, the Phase 1 Report presents a case that even a small number of EVs could defer the need for investment at the zone substation level for several years. The CSIRO's analysis has demonstrated that the economics of using EVs as peaking capacity is closely tied to the size of the battery, and the feed-in tariff rate that customers would expect to receive in return for providing grid support.

To date, aside from the CSIRO's Electric Driveway Project, limited research has been published regarding the potential benefits of EV batteries in providing network support during critical peak demand periods in Australia. There has been some suggestion that given critical peak demand represents such a small, undefined proportion of the year, the economic value of providing critical peak demand support may not justify the expense of both physical and regulatory requirements to ensure restricted charging and availability of batteries to the grid. The potential for EV batteries to supply ancillary services (including regulation of frequency and spinning reserves) is likely to present a greater economic case than peak capacity.[62] However, several researchers have pointed out that

[60] Denholm and Short, An Evaluation of Utility System Impacts and Benefits of Optimally Dispatched Plug-In Hybrid Electric Vehicles, October 2006

[61] CSIRO Electric Driveway Project, Plugging In: A technical and institutional assessment of Electric Vehicles and the Grid in Australia, Phase 1 Report, March 2011.

[62] Letendre and Dehholm, 'Electric & Hybrid Cars -New Load, or new Resource' in Public Utilities Fortnightly, December 2006; CSIRO p 63

the market for ancillary services is small and would likely achieve saturation with only a small number of participating customers.[63]

Limited battery capacity and the effect of grid support on battery life are currently some of the more challenging technical barriers to the use of EVs as peaking capacity. A 2009 US study on the economics of using EV batteries for energy arbitrage concluded that, even assuming perfect market information and that using EV batteries for grid support resulted in no battery degradation, the economic profit is likely to be between US$142 and $249, which is probably too low to provide much of an incentive for EV take up.[64]

In our view, there is a potential benefit associated with EV battery storage in managing peak demand, however, a comprehensive cost benefit analysis of using EV batteries as network support in Australia during peak times needs to be conducted to determine whether the costs of infrastructure and supporting regulatory frameworks would outweigh the benefits of reduced peak demand. We note that for EVs to provide peak demand support services through V2G, at a minimum the following conditions would need to be in place to enable this to occur:

- Utility controlled smart-charging, combined with suitable tariffs to provide incentives for customers to partake
- Subsidisation for customer's EV batteries – there is some evidence that using the EV batteries as grid support is likely to wear down the battery life. As such, appropriate arrangements would need to be in place to ensure customers are left no worse off in the long term costs of running their EV.

We note that the widespread adoption of EVs in Australia would also increase the potential benefits from time of use pricing, in turn increasing the likelihood that such tariffs would be mandated or rolled out on a large scale.

7.2 What is needed to achieve the benefits?

As for smart meters, the economic case for EVs does not rely on the potential reduction in peak demand and associated infrastructure. Benefits generated by lowering fuel consumption and greenhouse gas emissions represent the majority of the value associated with EVs, and are forecast to offset the associated costs of implementation.

AECOM and the Electric Driveway Project have published data on the likely cost of EVs and charging infrastructure in Australia over the next decade.[65] After reviewing this research, we have developed a range of high and low estimates of the forecast average EV price premium above ordinary vehicles over the next 10 years. These are presented in the following table.

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[63] Peterson, Whitacre and Apt, The Economics of using plug-in hybrid electric vehicle battery packs for grid storage, in the Journal of Power Sources, September 2009

[64] Peterson, Whitacre and Apt, The Economics of using plug-in hybrid electric vehicle battery packs for grid storage, in the Journal of Power Sources, September 2009.

[65] AECOM, Forecast Uptake and Economic Evaluation of Electric Vehicles in Victoria, Final Report, May 2011; AECOM, Economic Viability of Electric Vehicles - Department of Environment and Climate Change (NSW), September 2009; CSIRO Electric Driveway Project, Plugging In: A technical and institutional assessment of Electric Vehicles and the Grid in Australia, Phase 1 Report, March 2011.

Table 30: EV price premium – Deloitte forecast based on AECOM and CSIRO/ISF

Year	Low case – EV price premium forecast	High case – EV price premium forecast
2012-13	$16,250.00	$40,000.00
2013-14	$15,000.00	$36,666.67
2014-15	$13,750.00	$33,333.33
2015-16	$12,500.00	$30,000.00
2016-17	$11,250.00	$26,666.67
2017-18	$10,000.00	$23,333.33
2018-19	$8,750.00	$20,000.00
2019-20	$7,500.00	$16,666.67
2020-21	$6,250.00	$13,333.33
2021-22	$5,000.00	$10,000.00

Costs of commercial (workplace, public or battery swap stations) charging infrastructure vary significantly, from small scale public stations at $3,000 each, to $500,000 for a large commercial operation. Without a more detailed analysis of the forecast scenario, it is not possible to determine with any accuracy the likely future costs associated with charging stations. However, it is acknowledged that the costs of vehicles alone are not the only costs to implement EVs on a wide scale.

The following table presents the potential costs associated with our EV take up scenario to 2021-22 based on AECOM's forecasts for NSW and Victoria, discussed below.

Table 31: EVs – Cost estimates

	Low case – cost forecast ($m)	High case – cost forecast ($m)
AECOM forecasts – cars only	4,240	9,401

We note that our analysis does not incorporate the costs and benefits of customers using energy bought at off peak times to sell back into the grid at peak times, as we note that the implications of this would depend upon the retail market offerings that support V2G services.

7.3 What is the potential impact on peak demand?

Using the findings reported in a range of studies, discussed above, we have developed a range of potential battery capacity and assumptions regarding availability of cars and battery capacity for V2G supply.[66] Our assumptions are presented in the following table.

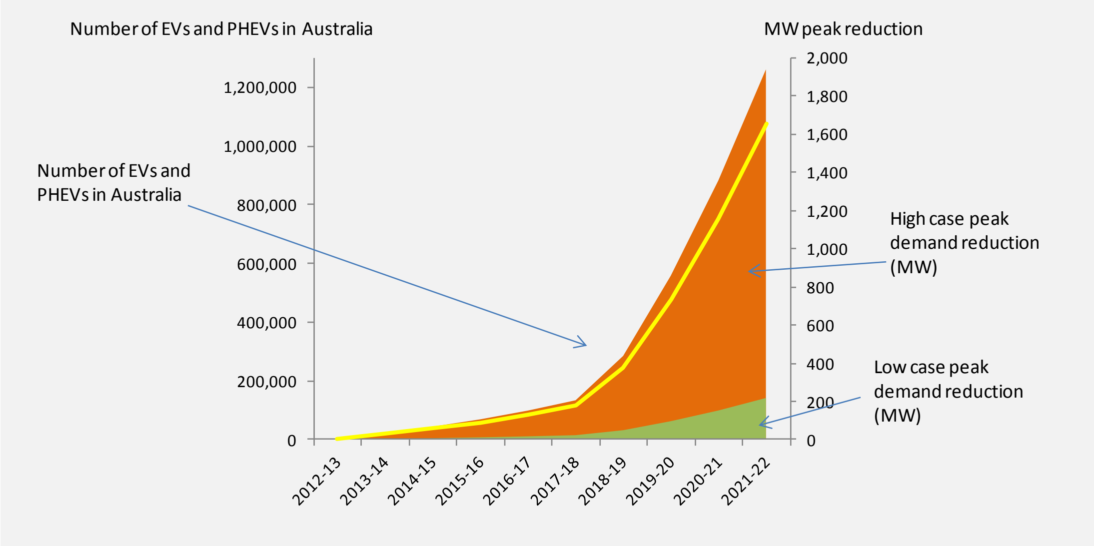
Table 32: V2G capability - Deloitte Assumptions

Benefits assumptions	Low case	High case
Maximum capacity per vehicle	10 kWh	24 kWh
% cars available at peak time	40%	60%
% of each car's load available at peak time	40%	50%
Discharge time	8 hours	4 hours

In order to present the potential benefits that initiatives to support the take up of EVs could hold for Australia, we have examined the benefits associated with a take up rate in line with the EV and PHEV forecasts prepared by AECOM for NSW and Victoria, extrapolated out to other states. Our forecast take up rates are presented in the following graph, along with our estimated peak load reductions under the high and low case scenarios.

[66] We note that, in assuming that EVs will be able to deliver energy to the grid at peak times from wherever they are parked and plugged in, we have not differentiated between the benefits and costs associated with V2G and Vehicle to Home capabilities of EVs in our analysis. We have essentially assumed that EVs plugged in at a customer's home during peak times will work by offsetting that customer's peak load, however we acknowledge that there are implications for this in relation to the import/export capabilities of inverters. A more detailed analysis of the different requirements and implications is needed to more accurately forecast the potential costs and benefits, which is beyond the scope of this engagement.

Figure 12: Electric Vehicles – take up rates and estimate peak load reduction scenarios (MW)



Note: This AECOM forecast has been estimated on the basis of extrapolation from graphical forecasts of EV and PHEV take up for Victoria and NSW, presented in AECOM's public reports.

7.4 Conclusion – value of potential benefits

In conclusion, we consider that the penetration of electric vehicles in Australia over 2012 to 2022 offers benefits in the range set out in the table below.

Table 33: Electric Vehicles – estimated value of benefits 2012-13 to 2021-22 (NPV, $m)

	Low case estimate ($m)	High case estimate ($m)
Electric vehicles (V2G)	60	537

Source: Deloitte analysis

8 Energy efficiency measures

Typically, measures to improve energy efficiency are aimed at lowering the volume of energy used over time (MWh) rather than demand specifically at peak times. However, some measures which are aimed at the drivers of summer peak demand (such as air conditioning) will also have an impact on peak demand. Two energy efficiency measures which could reduce peak demand are discussed in this section.

8.1 Increases in Minimum Energy Performance Standards for Air conditioning

8.1.1 What does it involve?

Air conditioning has been a major driver of peak demand in Australia over the past decade, with penetration rates now reaching over 90% of households in South Australia and 70% of households in Victoria.[67]

Minimum Energy Performance Standards (MEPS) is a mandated program operating throughout Australia and in New Zealand which determines the general regulatory requirements for appliances in terms of energy efficiency. Suppliers of products covered by MEPS must register their products with the Equipment Energy Efficiency Program E3 Regulators before they can be legally sold to Australian and New Zealand customers. MEPS are enforced by State Government legislation, with offences and penalties if parties fail to comply with the requirements, which are set out in Australian Standards (for example A/NZS 3823.2). Household appliances covered by MEPS include refrigerators and freezers, electric storage hot water systems, air conditioners, light globes and lamps, televisions and set top boxes.

Air conditioning is the single biggest appliance contributing to peak demand in Australia. Accordingly, improving the efficiency of air conditioners offers benefits in terms of lowering peak demand, as well as benefits associated with lowering overall energy use. However, limited research has been carried out to date on the peak load reduction benefits of improving air conditioner efficiency, due to a general focus on reducing overall energy use.

The National MEPS for air conditioning were introduced in 2001 and have been subsequently increased several times. In 2010 the Department of Climate Change and Energy Efficiency commissioned EnergyConsult to undertake an evaluation of the impacts of regulation of air conditioning in Australia since MEPS was introduced.[68] The final report, published in November 2010, found that the impact of MEPS on product efficiency and therefore energy consumption was considerable:

> *The annual rate of improvement (of product efficiency and energy consumption) before MEPS was around 0.5%, but grew to around 3% after the 2004 MEPS and to around 4% after the 2006/07 MEPS.*[69]

[67] ABS, 4602.0.55.001 - Environmental Issues: Energy Use and Conservation, March 2011.
[68] EnergyConsult Pty Ltd for the Department of Climate Change and Energy Efficiency, Evaluation of Energy Efficiency, Equipment Energy Efficiency Program: Policy Measures for Household Air Conditioners in Australia, November 2010.
[69] EnergyConsult Pty Ltd for the Department of Climate Change and Energy Efficiency, Evaluation of Energy Efficiency, Equipment Energy Efficiency Program: Policy Measures for Household Air Conditioners in Australia, November 2010, p. 1.

The cumulative energy savings over 2004 to 2020, based on estimated achievements to date, was forecast at 6,533 GWh.[70] No estimate of the impact on summer peak demand was provided in the evaluation report.

Most recently, MEPS for air conditioning were increased in October 2011, following a July 2009 request by COAG to examine the feasibility of a MEPS increase of 10% above April 2010 levels. Analysis of various options was carried out by the Equipment Energy Efficiency Committee, including options for amending the standards to introduce consistency across different sizes and types of air conditioners.[71] The cost benefit analysis included benefits associated with lowering peak demand, however, details on the actual assumed peak MW reduction for each option were not published and are not discernible from the published data. We note that the Regulatory Impact Statement did not take into account the impact of direct load control of air conditioners. The GWh savings anticipated under each of five scenarios are presented in the following table.

Table 34: MEPS for AC – Regulatory Impact Statement 2011 – forecast GWh per annum impacts

Scenario	2015	2020	2025
MEPS2010+10%: April 2010 +10% across the board	278	605	769
Proposal A: 10% above 2010 level, excluding non-ducted split systems	342	743	942
Proposal A1: Similar to A, but non ducted split systems would have an increased MEPS **(Implemented in October 2011)**	273	594	756
Proposal B: Greater than 10% above 2010 levels for most AC	324	860	1,158
Proposal C: 25% more efficient than 2010	591	1,839	2,652

Source: EnergyConsult Pty Ltd for the Equipment Energy Efficiency Committee under the auspices of the MCE, Decision Regulatory Impact Statement: Minimum Energy Performance Standards for Air Conditioners: 2011, December 2010.

Forecasts of peak demand typically take into account policies that are anticipated to have an incremental impact on system peak. In reviewing peak demand forecasts submitted by Victorian distributors in 2009, the AER considered the impact that the planned improvements in MEPS for air conditioning would have on the distributors' peak demand and therefore growth related infrastructure programs.[72] Distributors' peak demand forecasts were prepared by the National Institute of Industry and Economic Research (NIEIR), however, their methodology for assessing the impact of MEPS for air conditioning on peak demand was not publicly disclosed. The total estimated impact in terms of Victorian MW reduction was published, which provides a useful baseline for analysis of the expected impact of the increase in MEPS on network peak demand. The estimated impact of MEPS is presented in the following table, in MW and % of maximum demand.

Table 35: MEPS for Air conditioning – Forecast impact on peak demand in Victoria

	2011	2012	2013	2014	2015
AER - MEPS impact on 50 POE peak demand in VIC - As forecast by NIEIR	-9.4	-19.8	-31.4	-41.5	-50.9
% impact of MEPS on 50 POE peak demand in VIC	-0.1%	-0.2%	-0.3%	-0.4%	-0.5%

Source: ACIL Tasman, Victorian Electricity Distribution Price Review - Review of maximum demand forecasts - Final report, April 2010.

[70] EnergyConsult Pty Ltd for the Department of Climate Change and Energy Efficiency, Evaluation of Energy Efficiency, Equipment Energy Efficiency Program: Policy Measures for Household Air Conditioners in Australia, November 2010, p. 1.
[71] EnergyConsult Pty Ltd for the Equipment Energy Efficiency Committee under the auspices of the MCE, Decision Regulatory Impact Statement: Minimum Energy Performance Standards for Air Conditioners: 2011, December 2010.
[72] AER, Final Decision - Victorian Electricity Distribution Network Service Providers, Distribution Determination 2011-15, p. 95.

8.1.2 What is needed to achieve the benefits?

As for smart metering and EVs, the economic case for improving the energy efficiency of air conditioning does not rest on peak demand reduction benefits, rather relies on the energy consumption savings that such policies generate. Costs involved relate mainly to the requirement for air conditioning retailers and wholesalers to sell compliant goods after the legislation is passed in each State.

The MEPS for Air conditioning Regulatory Impact Statement Decision includes a detailed analysis of the costs of implementing each proposed scenario, including costs to manufacturers, suppliers and end customers. Costs of each scenario were presented on an NPV basis, reproduced in the table below.

Table 36: MEPS for Air conditioning – 2011 RIS – Total costs

	Total costs (NPV to 2020, 7% discount rate, $m)
MEPS2010+10%: April 2010 +10% across the board	968
Proposal A: 10% above 2010 level, excluding non-ducted split systems	1,395
Proposal A1: Similar to A, but non ducted split systems would have an increased MEPS **(Implemented in October 2011)**	1,015
Proposal B: Greater than 10% above 2010 levels for most AC	2,344
Proposal C: 25% more efficient than 2010	4,557

Source: EnergyConsult Pty Ltd for the Equipment Energy Efficiency Committee under the auspices of the MCE, Decision Regulatory Impact Statement: Minimum Energy Performance Standards for Air Conditioners: 2011, December 2010, p. 45.

8.1.3 What is the potential impact on peak demand?

Since its introduction in 2001, MEPS for air conditioning has achieved considerable reductions in summer peak demand, such that electricity distributors are now incorporating the impact of increases in MEPS into their five yearly peak demand forecasts.

However, there are some reports that suggest the potential to further increase the efficiency of new air conditioners may be limited. A 2010 Japanese study, as quoted in a presentation by Carbon Market Economics in September 2010, concluded that cost effective improvements in energy efficiency of air conditioners is virtually exhausted, based on the following factors:

- The motor efficiency of compression has reached 95%
- Heating insulation efficiency has reached 80%
- Improvement in recent years has been achieved by expanding the size of heat exchanges. Space restraints are likely to prevent significant increases in the future.[73]

[73] Jolly, R of Carbon Market Economics, Policy Roadmap for Energy Efficient Air conditioners, Presented at Energy Efficiency, Climate and China's Development Strategy, Beijing, 9 September 2010.

Carbon Market Economics reported that future efficiency savings in air conditioning are likely to be driven by improvements in the quality of ducting and ducting insulation for central air conditioners.

As noted above, there is very little published research to date on the impact of air conditioner efficiency on summer peak demand. While we considered that Proposal scenario C analysed in the 2011 MEPS Regulatory Impact Statement was a possible indicator of further future efficiencies in air conditioning, the significant costs and low cost benefit ratio estimated for this scenario suggests that it is not a viable, achievable initiative at this point in time.

Accordingly, while we consider there is definitely value in improving air conditioner efficiency in terms of peak demand reductions, we have not estimated a value for the purposes of this high level analysis. We note that the study on improvements in building standards incorporates savings resulting from retrofitting commercial buildings with more efficient cooling systems.

8.2 Improvements in building standards

8.2.1 What does it involve?

Improving the energy efficiency of buildings reduces their overall heating and cooling load, also lowering peak demand.

As part of the Australian Government's National Strategy on Energy Efficiency, investigations into the value of making changes to building regulations to improve and increase energy efficiency standards are currently being undertaken by the Department of Climate Change and Energy Efficiency. Several energy efficiency measures related to the construction industry were endorsed by the Council of Australian Governments (COAG) in 2009, including increasing energy efficiency standards in the National Construction Code, which incorporates the Building Code of Australia (BCA), and working to improve consistency in construction standards across jurisdictions.

Changes to the BCA to implement the National Strategy on Energy Efficiency were enacted in May 2010. Standards for new residential dwellings were increased, requiring 6 stars or equivalent, and commercial building standards were also increased. The new standards affected the following building features:

- performance of the building fabric;
- external glazing and shading;
- sealing of the building;
- effects of air movement; and
- performance of the building's domestic services, including hot water supply, insulation and sealing of ductwork and central heating water piping, space heating, artificial lighting, and the heating and pumping of swimming pools and spas.[74]

The Regulatory Impact Statement for these changes to the BCA did not attempt to model the benefits associated with avoided peak demand, although noted the potential value.[75] As discussed above, the focus of strategies to improve energy efficiency has traditionally been on the impact on energy consumption over time, rather than at peak times. As such, to date there has been limited research carried out on the impact of improving the energy efficiency of buildings on peak demand.

[74] Australian Building Codes Board website, available at: http://www.abcb.gov.au/major-initiatives/energy-efficiency/residential-housing Accessed 26 February 2012.
[75] Australian Building Codes Board (prepared by the Centre for International Economics), Proposal to Revise the Energy Efficiency Requirements of the Building Code of Australia for Residential Buildings — Classes 1, 2, 4 and 10, December 2009, Appendix F, p 226.

In 2003, the former NSW Minister for Planning commissioned a five year study into demand management which considered the costs and potential benefits of a range of demand management techniques and practices in terms of lowering the costs of serving peak demand, including energy efficiency measures.[76] The focus of the study was on 764 business customers within the NSW distribution network area of Ausgrid (formerly EnergyAustralia). In relation to energy efficiency, the study reported that between 17 and 88 MVA of savings could be generated by energy efficiency measures across the trial area, depending on the costs of the measures.[77] After reviewing the study, while useful in detailing the potential for energy efficiency to lower peak demand on specific customer sites, we noted that the presentation of results does not enable extrapolation across Australia to identify the potential savings delivered by energy efficiency, without a significant number of assumptions that we consider would undermine the analysis.

In recognition of the potential for energy infrastructure savings due to lower peak demand delivered by energy efficiency, and the lack of investigation or research into these benefits to date, in 2010 the Department of Climate Change and Energy Efficiency commissioned a national study into the peak demand benefits of various measures to improve the energy efficiency of buildings. The Building Our Savings study was jointly carried out by the Institute for Sustainable Futures and Energetics.[78] The focus of this study was on the savings generated by retrofitting existing buildings, particularly commercial buildings. The final report noted that changes to the BCA for new buildings would be expected to deliver savings in the medium to long term, beyond the 2020 timeframe for the study, however, also noted that changes to regulations for the retrofitting of commercial buildings could have a much shorter benefit delivery timeframe.[79]

Using a range of available data on energy efficiency and building on previously published work[80] on Conservation Load Factors (CLF) to indicate the contribution of features of residential, commercial and industrial buildings to both gas and electricity peak demand, the Building Our Savings study considered a range of energy efficiency measures under two scenarios:

- Moderate scenario – in which building performance improvements are carried out largely at the end of an investment's (for example, an appliance's) useful life. Under this scenario, replacement of investments by more efficient models will only impact 20% of the energy used in 2020
- Accelerated scenario – in which significant replacement of less efficient infrastructure is carried out before the end of its useful life, such that only 20% of end users will wait to the end of an investment's useful life to replace it with a more efficient model.

The following diagram, reproduced from the Building Our Savings report, illustrates these scenarios.

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[76] Demand Management and Planning Project, completed in June 2008. Details available on TransGrid's website: http://www.transgrid.com.au/network/nsdm/Pages/default.aspx Accessed 27 February 2012.

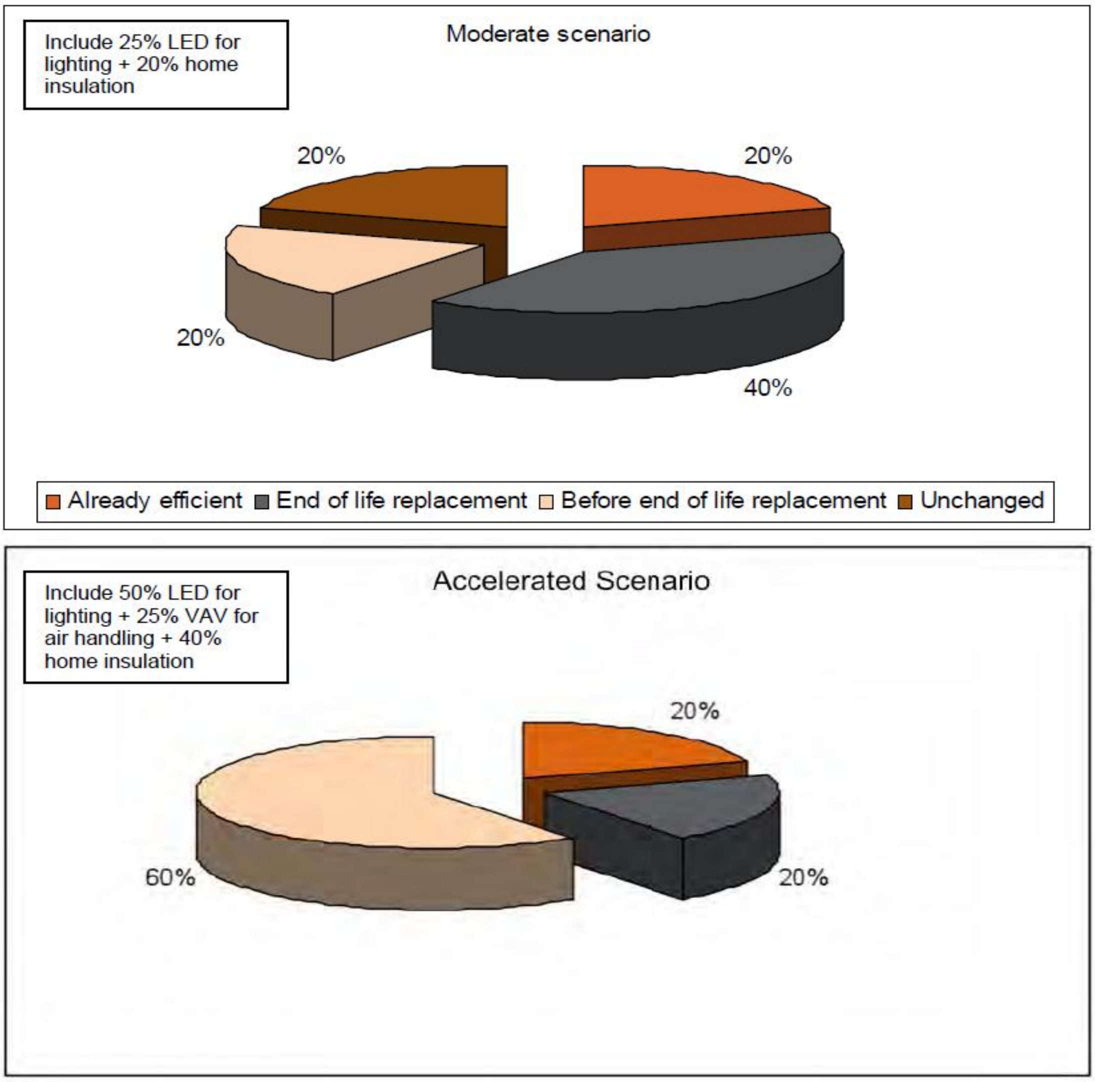
[77] NSW Department of Planning, EnergyAustralia and TransGrid - Demand Management and Planning Program – Final Report, June 2008

[78] Institute for Sustainable Futures and Energetics, Building Our Savings: Reduced Infrastructure Costs from Improving Building Energy Efficiency, Final Report, July 2010.

[79] Institute for Sustainable Futures and Energetics, Building Our Savings: Reduced Infrastructure Costs from Improving Building Energy Efficiency, Final Report, July 2010, p. 102.

[80] Including the Demand Management and Planning Program and a 2002 study by the Sustainable Energy Development Authority (SEDA) submitted to IPART's enquiry into the role of demand management (SEDA, Distributed Energy Solutions-Cost & Capacity Estimates for Decentralised Options for Meeting Electricity Demand in NSW, February 2002). The SEDA report published the potential MW savings from various energy efficiency measures, however, given the more recent Building Our Savings study drew on SEDA's earlier results, we considered it appropriate to rely on the more recent study results.

Figure 13: Building Our Savings report - Scenarios



The Building Our Savings study also considered the potential for cogeneration, standby generation, and time of use pricing to reduce peak demand, however, these benefits were not modelled.[81]

Energy savings measures that were modelled as part of this study include:

- Commercial measures: Voluntary Energy Star Program designed to identify and promote energy efficient products; Maintenance and cleaning of filters and coils of air handling, air conditioning, pumping and electrical heating appliances; Fine tuning and maintenance of lighting systems, sensors and controls; Installation of high energy efficiency air conditioning and dynamic lighting systems with controls; installation of more efficient air handling equipment
- Residential measures: Hot water demand reduction; Fridge buy-back scheme; Draught sealing; installation of new efficient lighting, hot water unit and air conditioners; installation of roof insulation

[81] Institute for Sustainable Futures and Energetics, Building Our Savings: Reduced Infrastructure Costs from Improving Building Energy Efficiency, Final Report, July 2010.

- Industrial measures: installation of new efficient lighting; Green-IT retrofits (affecting servers and power supplies); installation of LED lighting.

The study's estimates of the impact on summer peak demand are reproduced in the following table.

Table 37: Building Our Savings study – Reported results – summer peak demand

	Moderate scenario	Accelerated scenario
Maximum seasonal peak demand reduction (MW)	5,283	7,236
% of 2020 summer peak demand eliminated	10%	13%
% of 2010 to 2020 peak growth eliminated (Summer)	43%	58%

Source: Institute for Sustainable Futures and Energetics, Building Our Savings: Reduced Infrastructure Costs from Improving Building Energy Efficiency, Final Report, July 2010.

8.2.2 What is needed to achieve the benefits?

As for smart metering, MEPS for air conditioning and EVs discussed above, the business case for improving energy efficiency of buildings does not rely on peak demand reduction benefits alone. The costs of implementing improvements to the energy efficiency of existing buildings are substantial. Estimates of the total costs of implementing the changes modelled in the Building Our Savings study to 2020 are reproduced here for completeness.

Table 38: Building Our Savings study – Estimated total costs of implementing energy savings measures to 2020 ($m)

	Moderate scenario	Accelerated scenario
Cost of implementation – total costs to 2020	12,341	29,416

Source: Institute for Sustainable Futures and Energetics, Building Our Savings: Reduced Infrastructure Costs from Improving Building Energy Efficiency, Final Report, July 2010, Table 50, p. 96.

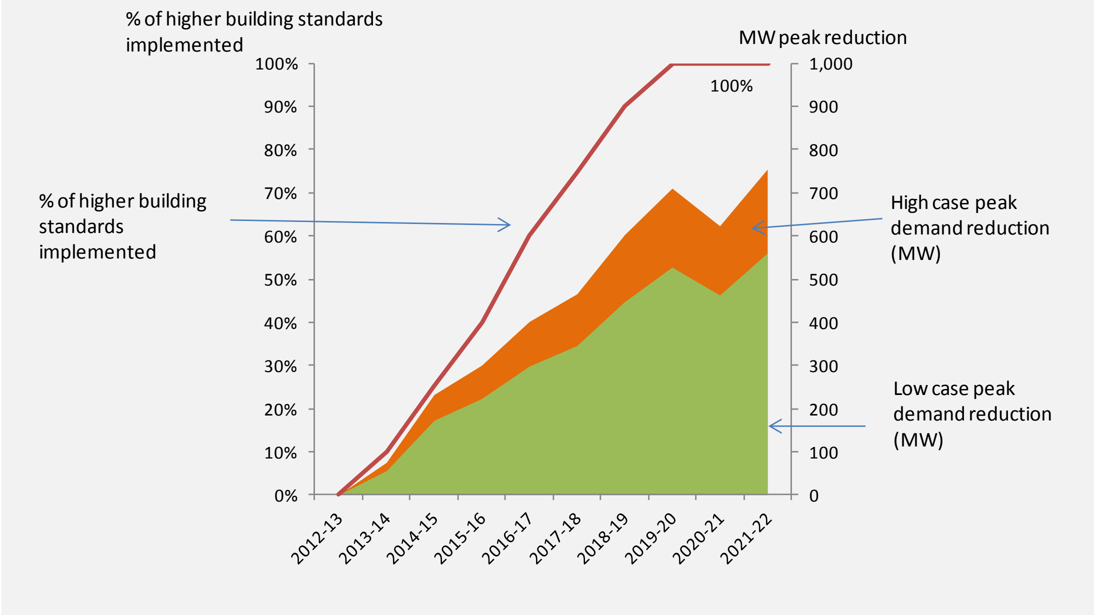
8.2.3 What is the potential impact on peak demand?

The Building Our Savings study reported a total potential reduction in growth in summer peak demand of 43% to 58% for the moderate and accelerated scenarios, respectively.[82]

A trajectory of potential take up of the energy savings measures has been estimated in the modelling of benefits, based on our expectations of an aggressive promotion of energy efficiency by Government. Take up rates and our estimates of potential peak demand reductions for the high and low case scenarios are presented in the following graph.

[82] We note that our analysis of peak demand savings has not relied upon the cost saving estimates presented in the Building Our Savings study.

Figure 14: Building standards improvements – high and low scenarios



Source: Deloitte analysis

We note that these benefits are attributed to the estimated impact of retrofitting commercial buildings with more energy efficient appliances, fittings and fixtures, as discussed in section 8.2.1. We acknowledge the potential for further benefits to be generated by increasing energy efficiency standards for new residential and commercial buildings (for example, seven star ratings), however, as discussed above, we were unable to find a reliable estimate of the potential impact of these measures on peak demand.

8.2.4 Conclusion – value of potential benefits

In conclusion, we consider that the implementation of certain measures to improve the energy efficiency of commercial, residential and industrial buildings over 2012 to 2022 offers benefits in the range set out in the table below.

Table 39: Energy Savings Measures – Building Our Savings study – estimated value of benefits 2012-13 to 2021-22 (NPV, $m)

	Low case estimate ($m)	High case estimate ($m)
Energy Savings Measures from the Building Our Savings study – potential value of reduced MW	361	486

9 Distributed generation

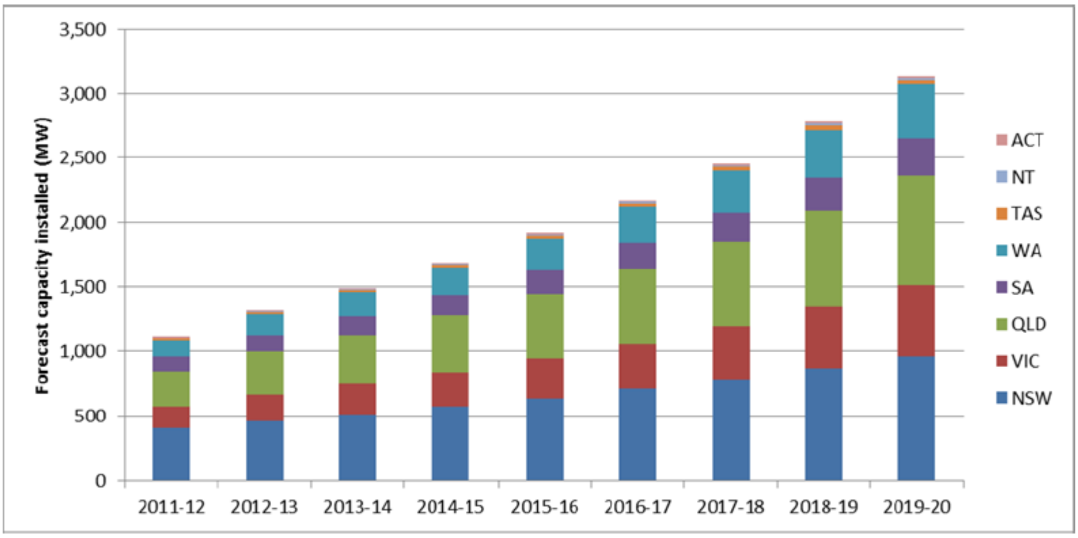
9.1 Small scale solar

9.1.1 What does it involve?

There has been a rapid increase in small scale solar generation in Australia over the past decade, driven principally by a reduction in the upfront capital costs and government initiatives stemming from the Renewable Energy Target and other direct incentives, such as feed-in-tariffs. Using data from the Office of the Renewable Energy Regulator, Futura estimated that the total installed capacity of rooftop solar systems in Australia in late 2011 was 630 MW.[83] AEMO has estimated that total solar PV generation capacity at the end of September 2011 was approximately 1000 MW.[84]

A recent Australia-wide forecast of small scale solar take up was carried out by ACIL Tasman for the Australian Energy Markets Commission (AEMC), submitted as advice to the MCE on the impact of the Renewable Energy Target.[85] A range of scenarios were modelled, from 'Core Scenario' based on current policy settings, to 'Elevated Uptake Scenario', incorporating various policy settings and a carbon price. The modelling incorporated variable inputs on up front subsidies and on-going assistance, retail electricity prices faced by households and small businesses and solar PV system costs over time.[86] ACIL Tasman's PV forecast is reproduced in the following figure.

Figure 15: ACIL Tasman forecast of solar PV installations by jurisdiction – under a carbon emissions price



Source: AEMC, Final Report – Impact of the Enhanced Renewable Energy Target on energy markets, 25 November 2011, p. 13.

[83] Futura Consulting, Power of choice – giving consumers options in the way they use electricity - Investigation of existing and plausible future demand side participation in the electricity market, Final Report, December 2011, p. 53.
[84] AEMO, National Transmission Network Development Plan 2011, p 9-2.
[85] AEMC, Final Report – Impact of the Enhanced Renewable Energy Target on energy markets, 25 November 2011; ACIL Tasman, Analysis of the Impact of the Small-scale Renewable Energy Scheme – Projection of retail electricity price impacts and abatement to 2020, November 2011, p. 42.
[86] ACIL Tasman, Analysis of the Impact of the Small-scale Renewable Energy Scheme – Projection of retail electricity price impacts and abatement to 2020, November 2011, p. viii.

The AEMC and ACIL Tasman reports did not publish the annual forecast figures for small scale solar, however stated that the forecast for 2019-20 under the Elevated Uptake Scenario (including a carbon price) was 3,136 MW.[87]

While generation situated close to the point of demand has the potential to avoid the use of network to transport electricity, research suggests that the performance of small scale solar generation at times of peak demand is not close to capacity. This is because times of summer peak demand are not always closely correlated with peak sunlight and PV generation. In addition, high temperatures reduce the potential output of PV.

A recent research paper published by Ausgrid indicated that the impact of rooftop solar on its summer peak demand has been small to date, despite the substantial take up in NSW. Using interval data from 26,744 installed solar systems over its peak demand period in early February 2011, Ausgrid noted that system peak time differed from the solar peak time, with the estimated output of the sample solar PV contributing only 32% of the total installed capacity of PV during the peak period. Ausgrid indicated that there has been no network investment deferral as a result of installed PV on its network. The most optimistic location on Ausgrid's network for PV to defer network investment was cited as Charmhave Zone Substation, however, Ausgrid noted that:

> *If the uptake of solar connections on this substation was about three times higher, then there could be enough peak reduction to defer a transformer upgrade for one year.*[88]

Ausgrid reported that, of the 51.6 MW of installed solar capacity studied, between 18 and 23.9 MW of peak demand was avoided over five summer peak days, representing between 0.30% and 0.43% of total summer peak demand on those days.[89]

Western Power's 2011 Annual Planning Report discussed the impact that PV is having on peak demand on its network. Western Power's 2011 annual demand forecast incorporates the expected impact of PV at times of peak. Western Power noted that:

> *The output of the PV systems is at a maximum in the middle of the day and early afternoon when the amount of direct incident sunlight is usually the highest (when) there is usually the least amount of shading of the solar panels to the sunlight. Historically the summer system peak occurs after 4:00pm when the solar activity is significantly less than in the middle of the day hence PV contribution to supplying electricity is also significantly reduced.*[90]

Western Power incorporated an anticipated reduction in maximum demand of 74 MW in 2012 rising to 133 MW by 2017 in its 2011 peak demand forecast.[91] Western Power published a report outlining its methodology for estimating the impact of PV on its network peak demand, based on assumed PV generation profiles.[92] The forecast PV impact was estimated based on an assumption that the maximum achievable load at peak times was 51.6% of total generation capacity. That is, for the forecast 148 MW of installed capacity in 2012, 76.3 MW was expected to be generating at peak times.[93]

As part of the 2011 National Transmission Network Development Plan (NTNDP) for the NEM, AEMO presented analysis of the potential impact on demand from widespread adoption of plug-in electric vehicles (not including V2G analysis) and increasing penetration of rooftop solar photovoltaic (PV) generation.[94] The solar analysis was based on a simulated PV generation system located in Sydney,

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[87] ACIL Tasman, Analysis of the Impact of the Small-scale Renewable Energy Scheme – Projection of retail electricity price impacts and abatement to 2020, November 2011, p. 43.
[88] Ausgrid, Research paper - Effect of small solar Photovoltaic (PV) systems on network peak demand, October 2011.
[89] Ausgrid, Research paper - Effect of small solar Photovoltaic (PV) systems on network peak demand, October 2011, p. 4.
[90] Western Power, 2011 Annual Planning Report, p. 46.
[91] Western Power, 2011 Annual Planning Report, p. 56.
[92] Western Power, Photovoltaic (PV) Forecast, 28 March 2011.
[93] Western Power, Photovoltaic (PV) Forecast, 28 March 2011, p. 20.
[94] AEMO, National Transmission Network Development Plan 2011, Chapter 9.

with climate simulation including ambient temperature and solar radiation at hourly intervals over a year, assuming a north-facing system with no shading at 30 degree tilt angle. AEMO also accounted for losses from system components.

The analysis on PV impact assumed a baseline of PV generation capacity of 2,000 MW. AEMO noted that this capacity figure was selected in order to explore the impact of generation capacity that is high enough to have a clear impact on the regional load profile, but that is still considered a reasonable projection given recent estimates of PV capacity in Australia. AEMO indicated that the output profiles could be scaled up or down directly to represent higher or lower capacities.[95]

Two scenarios were modelled:

- PV1 – with high output during summer, assuming a sunny summer day with little to no cloud. Under this scenario, the generation reaches its maximum of 1,633 MW at 11am, decreasing from then onwards, sharply decreasing after 5:30pm when the sun is lower in the sky
- PV2 – with low output during summer, assuming a hot and cloudy day. Generation reaches a maximum of only 60% of the PV1 scenario at 11am.

The results of AEMO's research are presented in the following table.

Table 40: AEMO Research on PV impact on peak demand - Results

Scenario	MW output at peak	Percentage of maximum potential solar PV generation output	Summer peak demand impact
PV1	418	26%	A 1.8% reduction in peak demand, shifted from 5:30pm to 6pm
PV2	373	23%	A 1.6% reduction in peak

Source: AEMO, National Transmission Network Development Plan 2011, p. 9-16.

9.1.2 What is needed to achieve the benefits?

Once again, the economic case for installing rooftop solar does not rest upon the value of peak demand savings it can generate alone, rather, most benefits are related to the reduced consumption of energy produced by emissions-intensive generation. However, we acknowledge that in order to achieve benefits, there are substantial costs, in particular upfront capital and installation costs.

Based on a literature review of PV system cost components, ACIL Tasman reported 2011 estimates of the total cost of PV installations per kW of installed capacity (before any subsidy), ranging between $5,000 and $6,400.[96] In forecasting system cost out to 2020, ACIL Tasman's analysis presented a decline in real costs.

To inform our estimate of the incremental costs associated with the Enhanced PV forecast, we reviewed ACIL Tasman's cost estimates and current market costs for small scale solar, and have assumed a real cost of $5000 per kW of installed capacity of PV in 2012, declining to $4000 per KW in 2021-22. Total costs of the Enhanced PV forecast scenario are presented in the following table.

[95] AEMO, National Transmission Network Development Plan 2011, p. 9-10, footnote 18.
[96] ACIL Tasman, Analysis of the Impact of the Small-scale Renewable Energy Scheme – Projection of retail electricity price impacts and abatement to 2020, November 2011, p. 24.

Table 41: Enhanced uptake of Solar PV – total system costs

	Total costs 2012-13 to 2021-22 ($m, NPV)
Enhanced uptake of Solar PV – total system costs	7,382

We also consider it is important to note the potential network costs associated with an increased penetration of solar PV, due to the impact of intermittent generation on system stability, including increases in harmonic levels, deterioration in power factor and voltage rise. Solar PV is also associated with interference with network protection operations, potentially causing network protection devices to fail to detect fault currents. A high penetration of solar PV that fluctuates over the day with sunlight is also likely to result in large power swings, requiring other forms of generation to step in and supply load, increasing the potential for network instability and outages.[97] We have not attempted to quantify the impact of these offsetting costs in our analysis, however acknowledge that they need to be taken into account in any detailed cost benefit analysis of significant take up of solar PV.

9.1.3 What is the potential impact on peak demand?

Based on the analysis of research papers discussed above, we have developed a range for the estimated impact of solar PV on summer maximum demand, per MW of installed PV capacity. For the NEM, the upper bound of the range reflects average findings from Ausgrid's 2011 research, while the lower bound represents AEMO's high case findings, published within the 2011 NTNDP.

For the SWIS, the high case estimate is based on Western Power's analysis of PV impact on peak demand, while the low case estimate is based on AEMO's study.

Table 42: Deloitte assumptions – Impact of PV on summer peak demand

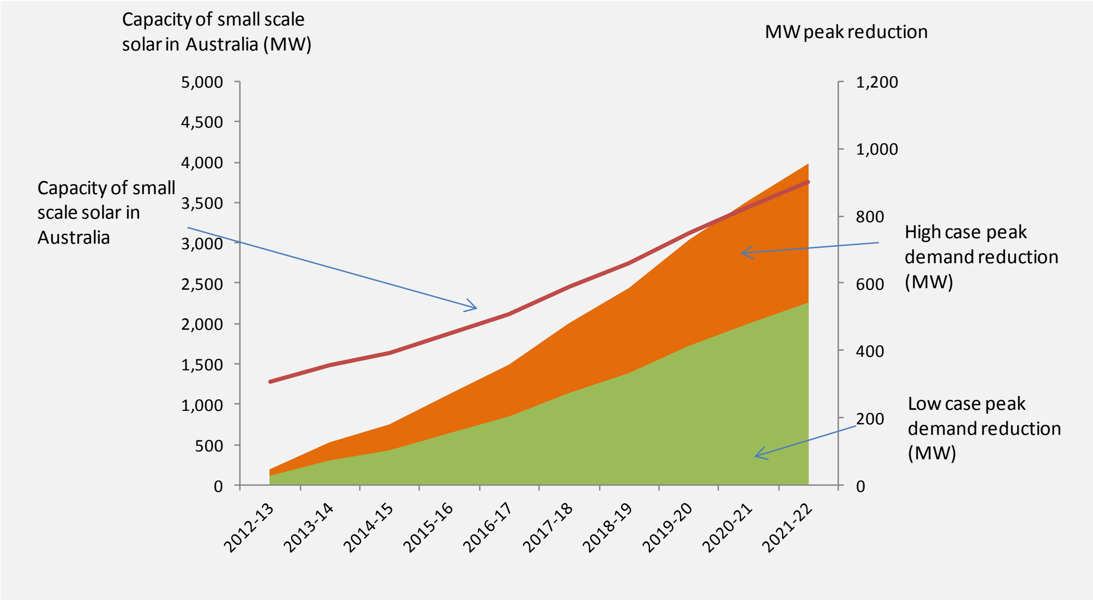
	Low case estimate (%)	High case estimate (%)
Reduction at summer peak per MW of installed capacity - NEM	20.9%	34.9%
Reduction at summer peak per MW of installed capacity - SWIS	20.9%	51.6%

Given Tasmania's winter peaking system, we have excluded benefits associated with the installation of solar PV in Tasmania from our analysis. Peak demand savings are weighted between the NEM and SWIS according to their relative summer peak demand data.

The following graph illustrates our assumptions regarding the take up of small scale solar and the potential peak load reductions under the high and low case scenarios.

[97] Endeavour Energy Power Quality and Reliability Centre, Small Scale Domestic Rooftop Solar Photovoltaic Systems, Technical Note 10, October 2011.

Figure 16: Small scale solar – Take up rate and potential peak load reductions – high and low case scenario



Source: Deloitte analysis

9.1.4 Conclusion – value of potential benefits

In conclusion, based on available research on the impact of solar PV on summer peak demand, we consider that the Enhanced Uptake scenario forecast by ACIL Tasman extrapolated over 2012 to 2022 could result in the range of benefits, as set out in the table below.

Table 43: Enhanced Uptake of solar PV– estimated value of benefits 2012-13 to 2021-22 (NPV, $m)

	Low case estimate ($m)	High case estimate ($m)
Enhanced uptake of Solar PV – value of potential reduction in peak demand	300	528

9.2 Cogeneration and trigeneration

Cogeneration (co-gen) is output from a small power plant located close to or inside a commercial or residential building, which uses fuel or solar energy to produce both energy and useful heat output that would otherwise be wasted. The heat output is generally used to provide thermal energy for heating the building. Trigeneration (tri-gen) takes this efficiency one step further, also producing energy that is used for cooling.

Co-gen and Tri-gen are highly regarded for their potential to lower overall energy use, and particularly for potential to lower greenhouse gas emissions. Co-gen and Tri-gen sites are emerging in all states of Australia, as financial incentives and emissions reduction targets encourage the use of renewable energy.

One of the best known distributed generation projects in Australia is the City of Sydney's *Sustainable Sydney 2030* plan. This project has a target for 360 MW of tri-gen to be operational by 2030, which if implemented, would reduce the city's summer peak demand by up to one third.[98]

To date, there have been no comprehensive national studies on the potential quantity of co-gen and tri-gen. At various times over the past decade, State governments have carried out research on the potential for co-gen and tri-gen in their jurisdictions, including some cost benefit studies. The Institute for Sustainable Futures conducted some high level analysis of the potential capacity of co-gen and tri-gen in Australia, based on previous studies on Victoria, Queensland, NSW, Tasmania and Western Australia. The Institute for Sustainable Futures reported that total potential capacity of co-gen and tri-gen is in the vicinity of 2,500 MW.[99]

To predict the impact of co-gen and tri-gen on peak demand would require a forecast of the potential capacity, as well as detailed studies on the contribution of various types of systems at times of peak demand. We consider that while the implementation of co-gen and tri-gen will undoubtedly result in lower peak demand in the NEM and SWIS over the next decade, it is not possible to develop a high level estimate of the potential value of these initiatives without a comprehensive national or recent state based forecast to draw upon.

[98] City of Sydney, Decentralised Energy Master Plan – Trigeneration 2010-2030; Futura Consulting, Power of choice – giving consumers options in the way they use electricity - Investigation of existing and plausible future demand side participation in the electricity market, Final Report, December 2011, p. 17;

[99] Institute for Sustainable Futures and Energetics, Building Our Savings: Reduced Infrastructure Costs from Improving Building Energy Efficiency, Final Report, July 2010, p. 40.

10 Conclusion

10.1 Summary of findings

In conclusion, our analysis of the available research and data relating to seven initiatives has yielded a total range of NPV benefits of between $1.6 billion and $4.6 billion over 2012-13 to 2021-22. The results are presented in the table below.

Table 44: Deloitte conclusion – Total estimated value of gross benefits 2012-13 to 2021-22 (NPV, $m)

Initiative	Low case benefits ($m)	High case benefits ($m)
Time of use pricing	58	193
Critical peak pricing and incentives	385	1,272
Direct load control of air conditioners	200	1,338
Direct load control of pool pumps	188	231
Electric vehicles	60	537
Energy Savings Measures	361	486
Enhanced uptake of Solar PV	300	528
Total gross benefits	**1,551**	**4,585**

Source: Deloitte analysis. Note totals may not sum due to rounding.

The net benefits realised by customers will depend upon the additional costs incurred to achieve these benefits, the regulatory framework and the competitive nature of the wholesale and retail markets.

To determine the precise impact on electricity tariffs is beyond the scope of this study and will depend upon the costs incurred to achieve the benefits. However, we have converted the calculated gross benefits into a $/MWh figure for residential customers, based on forecast residential electricity consumption. The results are presented in the figure below.

Putting aside the benefits associated with improving the energy efficiency of existing commercial buildings, in making this calculation, we have implicitly assumed that all benefits accrue to residential customers.

Figure 17: Domestic gross benefits translated into $/MWh

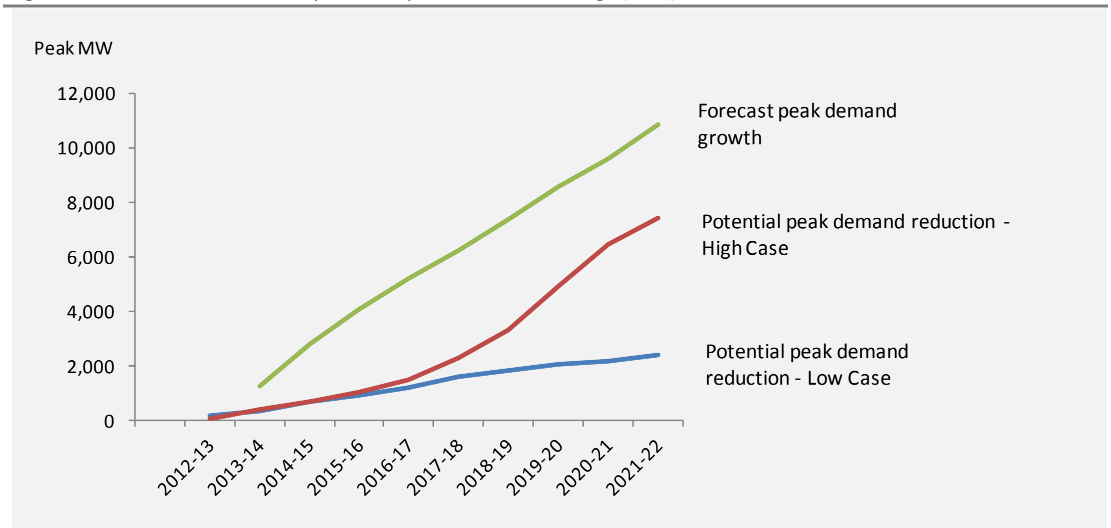
Source: Deloitte analysis

The gross benefits translated into a $/MWh figure for residential customers range from an average of $1.46/MWh to $4.09/MWh under the low case scenario and $4.47/MWh to $14.88/MWh under the high case scenario.

The actual electricity price impact for residential customers will be lower due to the additional cost incurred in achieving these benefits. The electricity price impact will also depend upon the regulatory framework and the competitive nature of the wholesale and retail markets.

The sum of potential peak demand reductions under the high and low case scenarios, as well as the forecast peak demand for the NEM and the SWIS are presented in the following graph.

Figure 18: Conclusion – Sum of potential peak demand savings (MW)



Source: Deloitte analysis

10.2 Additive nature of benefits

We consider that it is unlikely that all eligible and responsive customers will elect to be engaged in only one peak demand saving initiative each, should more be offered to them by electricity retailers or via marketing. However, we also acknowledge that when a customer is involved in more than one initiative, the potential savings from each initiative are reduced, as there is a finite amount of peak savings that can be delivered by a single customer. To account for this, we have moderated our take up rate assumptions at a global level.

As is presented in table 44, the majority of the quantified benefits are attributable to critical peak pricing incentives and direct load control of air conditioners. For these initiatives, we consider that customers curtailing their discretionary peak load, either through pricing incentives or load control, will deliver the majority of their benefits.

Given they are stemming from changes in the use of a small set of discretionary appliances, the additive nature of benefits from these particular initiatives needs to be considered. We have taken this into account in our assumptions regarding the scenarios on customer take rates. Under the high case scenario, we note that the take up rates reach a maximum of 30% for all residential customers for Dynamic Pricing and 16% for direct load control of air conditioning .

In short, assuming that the peak load reduction benefits of Dynamic Pricing and direct load control are delivered by different residential customers (implying that the maximum benefit can be derived from each initiative as each customer responds to each initiative to highest degree possible) results in 46% of residential customers being engaged. We consider this is a reasonable assumption, given the current technical, market and policy barriers to these initiatives.

The addition of the benefits of all quantified initiatives has also been considered at the global level, and taken into account in the individual take up rates for each initiative.

If we assume that each residential customer is only engaged in a single initiative (either Dynamic Pricing, direct load control, V2G or solar PV), the result is a maximum of 59% of residential customers being engaged in 2021-22 under the high case scenario. This assumption results in a maximum of 49% of customers under the low case scenario.

For building efficiency standards, the benefits we have estimated are to be delivered by retrofitting existing commercial buildings, targeting peak demand savings delivered by commercial customers. Accordingly, we consider it is reasonable to add savings from building efficiency standards to the potential savings from residential customers.

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