Reducing electricity costs through Demand Response in the National Electricity Market

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CME is an energy economics consultancy focused on Australia's electricity, gas and renewables markets.

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EXECUTIVE SUMMARY

EnerNOC Pty Ltd asked CME to produce estimates of the costs that could be avoided through Demand Response (DR) in the National Electricity Market (NEM). DR is an over-arching description for activities and technologies that reduce peak electrical demand when the economic value of that demand reduction far exceeds the value that consumers derive from consuming electricity.

The rationale for DR is that it reduces capital expenditure and subsequent fixed operating and maintenance expenditure in generation, transmission and distribution without detriment to reliability and security of supply. It does this by reducing the need for supply-side infrastructure that is only used for short periods of time, typically less than 100 hours per year. As a result it improves efficiency in the production and delivery of electricity, and potentially reduces the exercise of market power in wholesale markets. Through this, DR delivers lower electricity prices to all consumers.

The two questions that we have been requested to answer are:

a) what has been the marginal cost of expanding the network and generation capacity in the NEM to meet peak demand. This is the marginal expenditure that DR could avoid; and
b) what actual costs would have been avoided if various DR technologies and programs had avoided 3,000 MW[1] of the peak demand growth (in the NEM)?

The essence of our approach has been to use actual data – in regulatory accounts and related documents - on the costs of augmenting the capacity of the distribution and transmission networks. For generation we have used generally accepted data on peaking generation costs, since the actual cost of augmentation is generally not publicly available.

The intention with these questions (and their answers) is to produce sound estimates that are useful for policy-level analysis of the merits of DR programs, processes and technologies. Our response should be considered to be a broad estimate of avoided costs, rather than a precise estimate of the avoided costs associated with a specific DR program, process or technology.

The analysis in this paper is not a cost/benefit analysis – we have not attempted to calculate the expenditure incurred in DR, needed to achieve the avoided costs

[1] 3,000 MW is around 9% of NEM peak demand, which is comparable to the levels of DR in markets with mature DR mechanisms.

[2] Over and above the reduction associated with the long term price elasticity of demand

on the supply-side. The avoided costs referred to in this paper are therefore the supply-side avoided expenditures only.

On the first question we conclude that the cost per MW that is avoided through an effective DR program lies between $1.7million per MW and $6.2million per MW, with a NEM-wide Central Estimate of $5.3 million per MW. The reason for the large range is that actual network augmentation costs have varied significantly in the different regions of the NEM.

On the second question (avoided costs assuming 3, 000 MW reduction in peak demand) we conclude - using our Central Estimate - that the total avoided cost is $15.8bn. Since there are a little over 9 million connections in the NEM, this equals avoided costs per user of around $1,700.

We examined contemporary estimates of marginal augmentation costs in the NEM (and hence of costs avoided by DR) developed by other consultants and market participants. Most of these estimates are similar to ours and it appears that in most cases their approach has been conceptually similar to our approach.

The Council of Australian Governments' review (the "Parer Review' in 2002) and the report of the Energy Reform Implementation Group in 2006 recommended that action should be taken to strengthen demand-side participation. Our analysis leads to the conclusion that if the Parer Review recommendation had been implemented and 3,000 MW of DR had been available to reduce peak demand from what it is now, $15.8bn of expenditure on generation, transmission and distribution infrastructure could have been avoided.

Delivering the DR will require investment in businesses, technology, the procurement of demand reductions from consumers, regulatory changes or compensation to network service providers to induce them to forego the profits that they would otherwise collect through the expansion of the regulatory asset base. As we noted, we have not attempted to estimate these costs. However, our expectation is that for most DR programs and technologies, the cost of achieving the DR will be a small fraction of the cost of expanding the supply-side infrastructure to meet higher demand. "Benefits" are therefore likely to be many multiples of "costs".

Leaving aside the costs involved in achieving the DR, our analysis leads to the conclusion that if peak demand in the NEM was 3,000 MW lower than it is now, average electricity prices would be around 9% lower than they are now.

Table of Contents

List of Tables

1 Introduction

This report is our response to EnerNOC's request that we quantify the costs that would have been avoided through the implementation of "Demand Response" (DR) in the National Electricity Market (NEM).

DR is an over-arching description for a range of activities and technologies that reduce[2] peak electrical demand when the economic value of that demand reduction far exceeds the value that consumers derive from consuming electricity.

The rationale for DR is that it reduces capital expenditure and subsequent fixed operating and maintenance expenditure in generation, transmission and distribution without detriment to reliability and security of supply. It does this by reducing the need for supply-side infrastructure that is only used for short periods of time, typically less than 100 hours per year. As a result it improves efficiency in the production and delivery of electricity, and potentially reduces the exercise of market power in wholesale markets. Through this, DR delivers lower electricity prices to all consumers.

The two questions that we have been requested to answer are:

a) what has been the marginal cost of expanding the network and generation capacity in the NEM to meet peak demand. This is the marginal expenditure that DR could avoid; and
b) what actual costs would have been avoided if various DR technologies and programs had avoided 3,000 MW of the peak demand growth (in the NEM)?

The intention with these questions (and their answers) is to produce sound estimates that are useful for policy-level analysis of the merits of DR programs, processes and technologies. Our response should be considered to be a broad estimate of avoided costs, rather than a precise estimate of the avoided costs associated with a specific DR program, process or technology.

Section 2 sets out the results of our calculation. Section 3 describes the methodology of our calculation. The last section surveys the calculations that others have done to estimate the marginal cost of expanding the network and generation capacity in the NEM to meet peak demands.

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[2] Over and above the reduction associated with the long term price elasticity of demand

2 Results

This section sets out the results of our analysis. The results are presented for DR in the NEM. The costs avoided through effective DR in the NEM vary considerably between Victoria (VIC) on the one hand, and New South Wales (NSW), Queensland (QLD) and Tasmania (TAS) on the other where the network expenditure per MW of demand has been much higher than in VIC. A detailed description of the methodology that has produced these results is set out in the next section.

In our results we account for the variation in the avoided costs of DR in the NEM by presenting a "Lower Bound" which corresponds to the avoided costs in VIC, and an "Upper Bound" which corresponds more closely to the avoided costs in NSW, QLD and TAS. Avoided costs in SA, per MW, are in-between those in VIC, and those in NSW, QLD and TAS. The Central Estimate is a NEM-wide weighted average[3].

The second column in Table 1 is the Present Value of costs avoided through DR, per MW of additional capacity that is avoided. This can be thought of as the value of the benefit that energy users obtain by avoiding the need to expand the infrastructure to meet demand growth that could be avoided.

The third column states the Present Value as an Annualised Value. Conceptually this annualised value can be thought of as the ongoing annual charge that energy users incur for building 1 MW of additional capacity in generation, transmission and distribution.

Table 1. Present Value and Annualised Value of costs avoided through DR (2012 $million per MW)

	Present value ($million / MW)	Annualised Value ($million / MW / year)
Lower bound	$1.7	$0.12
Central Estimate	$5.2	$0.37
Upper bound	$6.1	$0.43

Table 2 shows the break-down – between generation, transmission and distribution - of the Present Value of costs avoided through DR. It shows that for

[3] The weighting is by the proportionate level of demand-related expenditure (for transmission and distribution costs). For transmission and distribution operating costs, and generation costs, the lower and upper bound is 15% either side of the Central Estimate.

the "Lower bound" (i.e. in VIC) the value of the costs per MW avoided in distribution is approximately comparable to the costs avoided in generation and about three times the size of the costs avoided in transmission. For the "Upper bound", the avoided costs in transmission and distribution are far higher than the avoided costs in generation.

Table 2. Value chain break-down of Present Value of costs avoided through DR (2012 $million per MW)

	Transmission	Distribution	Generation	TOTAL
Lower bound	$0.23	$0.77	$0.65	$1.65
Central Estimate	$1.32	$3.13	$0.77	$5.22
Upper bound	$1.49	$3.72	$0.89	$6.10

The results presented in Table 3 answer the second question of this study: what actual costs would have been avoided if DR technologies and programs had reduced peak electrical demand in the NEM by 3,000 MW. It shows that, for the Central Estimate, the present value of the avoided expenditure is $15.8bn. Since there are a little over 9 million connections in the NEM, this equals avoided costs per user of around $1,700.

Table 3. Present Value of costs avoided in the NEM through DR assuming 3,000 MW of DR available

	Transmission ($million)	Distribution ($million)	Generation ($million)	TOTAL ($million)	Per connection ($ per connection)
Lower bound	$719	$2,308	$1,963	$4,990	$542
Central Estimate	$4,147	$9,390	$2,309	$15,846	$1,722
Upper bound	$4,707	$11,172	$2,655	$18,534	$2,015

Delivering the DR will require investment in businesses, technology, the procurement of demand reductions from consumers, and perhaps also compensation to network service providers to induce them to forego the profits that they would otherwise collect through the expansion of the regulatory asset base. As we noted, we have not attempted to estimate these costs. However, our expectation is that for most DR programs and technologies, the cost of achieving the DR will be a small fraction of the cost of expanding the supply-side infrastructure. "Benefits" are therefore likely to be many multiples of "costs". Leaving aside the costs involved in achieving the DR, our analysis leads to the conclusion that if peak demand in the NEM was 3,000 MW lower than it is now, average electricity prices would be around 9% lower than they are now.

3 Methodology

This section describes the methodology that we have used to calculate the avoided costs of DR. It also examines the methodology that others have used.

The expenditure that is avoided through DR includes capital outlays to expand capacity and subsequent fixed operations and maintenance expenditure on that additional capacity. Such capacity includes:

- power generation and the upstream infrastructure (gas production, shipping and reticulation) needed to ensure a secure fuel supply to those gas turbines; and
- transmission and distribution networks needed to deliver electricity to the point of use.

Avoided generation costs

Our analysis assumes that the avoided generation capacity needed to meet peak demand is Open Cycle Gas Turbine (OCGT). In the centralised dispatch of generation in the NEM, and assuming a competitive market, this is (generally)[4] likely to be the generating technology that meets the last increment of demand.

OCGT has a lower capital cost and higher production cost than the generators that produce the bulk of the electrical energy and that frequently meet the marginal demand[5]. It may be the case (and usually is the case) that there is sufficient base load and mid-merit plant to meet demands without the dispatch of OCGT capacity. When this is the case, the avoided cost of DR is actually the (higher) capital and fixed costs associated with this generation. We have erred on

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[4] It should be recognized that this is only likely to be generally true. In many cases the market is not competitive and lower marginal cost generating capacity might be dispatched after gas turbines (because the lower cost capacity has only made its production available to the market at very high prices). In addition, in many cases even if the market is competitive reciprocating engines fueled by distillates or turbines fueled by refined hydro-carbons will be the last units dispatched to meet marginal demand in many settlement periods in the NEM.

[5] In nomenclature that harks back to the industry's past as a centrally planned and controlled industry, such generation is called "base-load" or "mid-merit", in recognition that they meet the "base" demand or are in the "middle" of the dispatch merit order. While these terms have wide recognition they are poorly adapted to distinguish generation technologies in a context in market in which generators determine their dispatch based on their individual offers and often irrespective of their cost structures.

the side of caution by adopting the (lower) estimate of OCGT capital and non-fuel fixed costs in our calculation.

In addition, we have not accounted for expenditure associated with the expansion of the gas production and pipeline infrastructure needed to deliver gas to OCGTs. Some indeterminate part of this cost will be recovered through gas consumption charges (and hence should not be counted as an avoided DR cost). The fixed element (not recovered through variable consumption charges) is relevant to a calculation of the avoided costs of DR. While we do not expect that the absence of this cost in our calculation is a significant exclusion, through its exclusion we have erred on the side of caution.

The data for our "Central Estimate" of the capital and fixed operating costs of OCGT is the Bureau of Resource and Energy Economics' 2012 Australian Energy Technology Assessment. We have set upper and lower bounds at plus and minus 15% from the Central Estimate.

Avoided transmission costs

The transmission system conveys electricity from remote generators to bulk points of supply to distribution networks and also to a few large end users. The transmission system is built to meet peak demands, to provide reliable supply, and to cater for the location of generators.

Other than VENCorp (whose transmission planning function is now undertaken by AEMO), TNSPs provide a budget for "load-driven capex" as part of their applications to the Australian Energy Regulator for the determination of their Maximum Allowed Revenues during 5-year revenue control periods. Load-driven capex is capital expenditure that is caused by higher peak demand.

In Victoria, all capital expenditure planned and procured by VENCorp (now AEMO) on the Victorian power system is driven by network augmentation (SP Ausnet is accountable for the expenditure related to replacement, maintenance or operation of the existing infrastructure).

We have used the data on actual and forecast load-driven capex for all TNSPs except VENCorp (and the actual and forecast network augmentation expenditure by VENCorp), and converted all data to 2012$.

We have then used data from AEMO on the actual peak demand in the various NEM regions to calculate the trend growth rate in annual peak demand, calculated as the gradient of the linear regression of actual demand over 10 years (for South Australia and Tasmania), 11 years for Victoria and 14 years for

Queensland[6]. Average annual load driven capex divided by the trend rate of growth gives the average annual load driven capex per region.

From these data a maximum, minimum and weighted average is calculated. The weighted average is the Central Estimate. The results are grossed up for three percent average transmission losses.[7]

For the estimation of fixed operations and maintenance costs associated with load driven capex we have simply calculated, for each TNSP, the average annual operating expenditure of each TNSP divided by average annual maximum demand to yield a $ per MW operating cost. We have then reduced this by 75% to reflect the fact that much of the operation cost is invariant to the expansion of the network. We have then calculated the present value of the net amount, assuming a 7% discount rate and 40 year asset life. The actual maximum, minimum and average value of these corresponds to the highest cost TNSP, lowest cost TNSP and the average of all TNSPs. A better estimate of the fixed operation and maintenance cost of load driven capex would also take account of the capitalised operating and maintenance expenditure. The data for this is not available. Our estimate is likely to be conservative but we don't consider the exclusion of capitalised operating and maintenance expenditure is likely to be significant.

Avoided distribution costs

To calculate avoided distribution costs we have developed a conceptually similar calculation to the one we have developed for transmission.

We have used information on growth-driven capex in the AER's decisions of the maximum allowed revenues / prices for each Distribution Network Service Provider (DNSP) for the regulatory period currently under way. For the Queensland and NSW distributors this is known as "Growth Capex", for the South Australian distributor "demand driven capex" and for the Victorian distributors "gross demand connections capex" less "customer contributions". For each DNSP we calculated the trend rate of demand growth based on actual demand (the trend rate being the gradient of the linear regression of this demand data.

The average annual growth-driven capex divided by the trend growth in demand gives the measure of growth driven capex assuming that the average annual trend rate of growth is maintained. Recent data suggests that the trend rate of

[6] The different periods are affected by the availability of load driven capex data.

[7] Average transmission losses in the NEM are around 3%, and marginal losses are around twice average losses. Strictly speaking it would be more accurate to have used marginal losses.

demand growth has declined and thus our measure is likely to be a conservative estimate of the growth driven capex per MW of demand growth. Again, as for TNSPs, we have calculated minimum, maximum and a weighted average, the latter being our Central Estimate, and again each has been grossed up for 10% average distribution losses.

We have calculated the fixed operations and maintenance cost for load-driven distribution capex in the same way as for transmission capex.

Finally, it should be recognised that DR for end users located at higher voltages in distribution networks will not avoid load driven capex that is related to demand from end users at lower voltages. As such, it would be inappropriate to assume that, on average, a MW of DR in distribution networks will lead to a MW reduction in load driven capex in distribution networks (as it would in transmission networks). In recognition of this, we have reduced our distribution avoided cost estimates described above, by 25%.

Competition benefits

DR can increase the short-term price elasticity of demand, and therefore make it more difficult for generators to raise prices in the spot market through the exercise of market power. This can reduce wholesale prices and hence profits to producers and increase the surplus available to consumers. Some economists describe such re-allocation of profits as "wealth transfers" and thus exclude them from the calculation of benefits (or in this case the avoided costs of DR). A wider perspective recognises that such profit reallocation can often improve dynamic efficiency (longer term investment efficiency) and that improvements in productive efficiency associated with greater competition are substantial.

Regardless of the economic arguments on the eligibility of such competition benefits, it is important to be clear that the issues here are significant. For example in South Australia in 2008 and 2009, the exercise of market power in the 70 highest priced half-hourly settlement periods raised average annual NEM prices in South Australia by around $55/MWh[8]. This flowed through to consumers in significantly higher contract prices. To the extent that DR is able to reduce the opportunity for the exercise of market power, the potential impact on spot prices and hence on costs to users, can be very significant. In present value terms this has substantial value.

For example, assuming that available DR had the effect of reducing the exercise of market power so that average annual spot prices in the NEM were reduced by

[8] This is described in detail in Mountain B., 2012. "Market power in South Australia". A report to the Energy Users Association of Australia, publication forthcoming.

$1/MWh in perpetuity, the present value of this, discounted at 7% would be $2.9bn.

However it is impossible to be certain about the impact of DR on spot prices, not least because it is impossible to predict the extent of market power in the future. If there is a substantial volume of DR, say 3,000 MW across the NEM, it is reasonable to assume that it will have a significant impact on the ability of generators to exercise market power.

In view of the uncertainty on the extent of this benefit, we have excluded it from our quantification. On assessing the costs and benefits of DR we suggest that the absence of quantification should not lead policy makers and regulators to ignore the potentially significant competition benefits that might arise.

4 Others’ estimates of avoided costs

This section describes some other contemporary calculations in Australia (or to be more precise in the NEM) of the avoided costs associated with DR. As the section explains, all the calculations have approached the subject in a similar way to the way that we have (with the exception of an estimate calculated by Deloittes in a report they undertook for the Energy Supply Association of Australia). The results in these other calculations (with the exception of Deloitte’s) differ from ours somewhat, but not by much in most cases.

The examination of the avoided costs associated with DR in North America is significantly more sophisticated than in Australia and for the reader interested in understanding their approaches to the calculation of the avoided costs in the North American context we refer to a helpful report for the Lawrence Berkeley National Laboratories’ “Demand Response Valuations Frameworks” prepared by Global Energy Associates.

Ergon Energy

In a submission to the Prime Minister’s task group on energy efficiency, Ergon estimated that expected peak demand growth on their network between 2009 and 2019 (1,246 MW) would require additional expenditure of $4.4bn in generation, transmission and distribution, giving an overall incremental cost of $3.5m/MW.[9] The methodology of their calculation is not clear, but conceptually it seems to be consistent with the approach that we have followed. Their estimate is within the range of our calculations but below our Central Estimate.

Institute for Sustainable Futures and Energetics for the Department of Climate Change and Energy Efficiency

In a report[10] for the Department of Climate Change and Energy Efficiency, the Institute for Sustainable Futures and Energetics estimated annualised electrical infrastructure cost savings for each Australian jurisdiction, and also calculated a national average. The methodology in their report is reasonably transparent, and is generally consistent with the definition and classification of avoidable expenditure in our analysis.

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[9] Ergon Energy submission to the Prime Ministers’ Task Group on Energy Efficiency: Issues Paper, 30 April 2012.

[10] Institute for Sustainable Futures and Energetics, July 2010. “*Building our savings: reduced infrastructure costs from building energy efficiency*”.

The minimum annualised saving was $0.14m/MW, the maximum $0.53m/MW and the National Average $0.29m/MW. Stated as an implied present value, the report estimates the national average savings attributed to DR would be $6.54m/MW. This is at the top end of our calculation of the range of avoided costs.

AusGrid

In their submission to the AEMC Power of Choice Directions Paper, AusGrid calculated the unit cost of meeting peak demand (we presume they were referring to a NEM wide calculation) of $3.3m per MW, split between distribution ($1.5m per MW), transmission ($0.8m) and peaking generation ($1.0m/MW).[11] By implication the cost avoided from DR would be equivalent to their estimate of the cost of meeting peak demand.

Their calculation has a few footnotes but there is insufficient information to discern their methodology in any meaningful sense. The fundamental calculation that they have performed seems to be similar to the one we have done, and their result is within the range of our calculations, although below our Central Estimate particularly in respect of the marginal cost of expanding distribution capacity.

Institute for Sustainable Futures (ISF) for Sustainability Victoria

In a report[12] prepared for Sustainability Victoria, ISF calculated the marginal cost of meeting additional demand in Victoria to be $1.1m per MW. The methodology of their calculation is consistent with ours, and their estimate of the marginal cost of meeting additional demand in Victoria agrees closely with our estimate of avoided costs in Victoria.

Deloittes for the Energy Supply Association of Australia (ESAA)

In a report for the ESAA, Deloittes calculated what they called the average annualised cost to provide an incremental kilowatt of peak demand in Australia. They used estimates of the long run marginal costs of the lower voltage part of the distribution networks, provided by five of the 12 DNSPs in the NEM. They excluded the costs of transmission and the costs of the higher voltage part of the distribution networks.

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[11] Letter from Mr George Maltabarrow, CEO, Ausgrid, to AEMC, 4 May 2012.

[12] Institute for Sustainable Futures, November 2011. "*Decentralised energy costs and opportunities for Victoria: A report for Sustainability Victoria*".

We suggest their methodology has little to commend it. Specifically, long run marginal cost calculations are well accepted in the development of electricity tariffs for network monopolies. However there is no reasonable basis to its use in the calculation of avoided expenditure through DR. Deloitte's use of LRMC in the calculation of avoided costs suggests a misunderstanding of the theoretical basis to long run marginal costs. Unsurprisingly, their estimate of the average annualised cost per MW of avoided network investment (between $0.044m/MW and $0.071m/MW) seems implausibly low. For example in 2012, regulated DNSPs alone (i.e. not even including TNSPs) will recover around $0.26m/MW through regulated charges – around five times more than Deloitte's lower estimate of the total incremental investment cost. Deloitte's estimate is also far below the other estimates that we are aware of, including those provided by Ergon Energy and AusGrid (cited earlier), which on a comparable basis are around 5 to 8 times higher than Deloitte's.