carbon + energy markets

Energy users' perspectives on the proposed Demand Response Mechanism in the National Electricity Market

A report for the Energy Users Association of Australia

June 2014

EXECUTIVE SUMMARY

In 2012, after a protracted review, the Australian Energy Markets Commission (AEMC) recommended that a demand response mechanism (DRM) should be implemented to enable energy users to participate more directly in the wholesale electricity market. During much of 2013, the Australian Energy Market Operator (AEMO) developed the business architecture to implement this recommendation and was ready to submit an application to approve this to the AEMC, at the end of the year.

However, shortly before an important meeting of the Standing Council of Energy and Resources (SCER) in December 2013, the Energy Retailers Association of Australia (ERAA) and the National Generators' Forum advocated to energy ministers that DRM not be implemented since its benefits did not exceed its costs. In response, SCER decided that the matter be remitted to SCER staff for advice. As a result, the question not of how to implement DRM, but whether to implement it, is still on the agenda.

In this context, this report has been commissioned by the Energy Users Association of Australia (EUAA) to present perspectives from energy user on the issue, for subsequent consideration by policy makers and their advisors, and also for consideration by the wider community. The production of this report has been partially funded by the Consumer Advocacy Panel.

In this report we consider three main questions:

- Can (and do) retailers deliver energy user participation in the wholesale electricity market ?
- Does the cost/benefit analysis that the ERAA and its associates submitted, withstand scrutiny ?
- What has been the experience in the various electricity markets in the United States, where there has been significant progress in making demand responsive to wholesale market prices ?

In the preparation of this report, we also canvassed the views of the members of the Energy Users Association of Australia on whether they thought DRM would be valuable.

Can (and do) retailers deliver energy user participation in the wholesale electricity market ?

Energy retailers can facilitate the involvement of their customers in the wholesale electricity market by promoting spot-priced based electricity contracts. They can also offer to buy demand reductions from their customers. Do they do this?

It is difficult to be certain on the volume of demand in the NEM that is currently responsive to wholesale prices, but the evidence seems to be as follows:

- There are only two "pure" end users that are registered market participants in the NEM (another two also control and partly own a significant amount of generation).

- Some retailers are known to offer electricity contracts linked to spot markets, but we understand they are generally reluctant to do this, since it offers brokerage fees rather than retailing margins. Some second tier retailers – such as Progressive Green – and more recently Macquarie Bank are apparently specialising in offering spot-linked contracts. However it remains a niche business and even where spot linked contracts are offered we understand that some level of hedging of extreme prices is also incorporated. This hedging undermines the incentive to reduce demand at the times most valued in the market.
- Both AEMO and the ERAA report limited levels of wholesale market price—responsive demand.

The conclusion we draw from the argument and evidence is that the volume of demand that is responsive to wholesale prices is in fact small. However the NEM is a highly volatile market and the historic data suggests that users could achieve substantially lower prices at times by procuring directly from the spot markets rather than on contracts. We calculated that over the period from 2007 to 2013, if energy users did not consume electricity in the 72 highest-priced half hours in each year (0.04% of the time) they could reduce their wholesale electricity costs by 15-40% depending on their location in the NEM. Indeed in some regions, for example South Australia, they could have more than halved their wholesale bill in several years by avoiding the 72 highest price half hours.

In addition to retailers' general preference to retail electricity rather than offer spot market brokerage, it seems that retailers, in general, are also unlikely to be well disposed towards compensating their customers to reduce demand, for the following reasons:

1. The value of demand response to most commercial and industrial energy users is likely to be small relative to the value they derive from more competitive retail offers. By implication, retailers are not likely to find a significant improvement in their competitive advantage by offering demand response to their customers.
2. Retailers – who mostly also own generators – are likely to prefer to sell electricity to sustain the value of their generation assets, rather than find ways for their customers to buy less electricity.
3. Successful provision of demand response requires expertise that is not core business in electricity retailing. It is necessary to understand the customer's loads and behaviour, identify which specific bits of plant can be curtailed, and then persuade the customer's operational staff that it's a good idea. Successful delivery then requires expertise in telemetry, remote control, testing, and a means of maintaining an ongoing relationship.
4. The successful sale and implementation of demand response is resource and potentially capital intensive. But retail contracts are typically 2-3 years. This limited duration means that bundling demand response with retailing is likely to diminish the potential market for demand response. This is because short duration contracts will require short payback periods.
5. From a retailers' perspective demand response may be a poor substitute for hedges obtainable in the financial market.

The evidence seems to support the conclusion that demand buy-backs are generally unlikely to be attractive to retailers: A survey by the ERAA of its members suggests that there is around 100 MW of price-related demand response, equivalent to around 0.3% of peak demand. By comparison, the Federal Energy Regulatory Commission in the United States observed demand response resources of around 6% of peak demand, albeit that only part of this is accounted for through demand buy-back schemes.

The conclusion from this seems to be that electricity users in Australia can obtain substantial benefit by reducing their demand when wholesale prices are very high, but more than 15 years since the market was created few have obtained such benefits.

Does the cost/benefit analysis that the ERAA and its associates submitted withstand scrutiny ?

Seed Advisory undertook the cost/benefit assessment for the ERAA. They concluded that the benefits were about a third of the costs. We agree with much of Seed's analysis, although we disagree with the duration of their cost/benefit calculation and the discount rate they used. On duration they only looked ahead for 10 years when 19 years of benefit projection was available. Since the bulk of the benefits of the DRM (based on currently available forecasts) occur after 10 years but much of the cost is upfront it is hardly surprising that they conclude as they have. Similarly on discount rates, Seed used a rate of 7.1% real, far higher than consistent with the recommendation of Infrastructure Australia on rates to be used in public sector comparators, and far higher than the rates used in the assessment of costs and benefits of infrastructure in developed economics that are comparable to Australia.

Once we have corrected the analysis by adopting more orthodox assumptions on duration and discount rate appropriate to the calculation of the costs and benefits of long-lived infrastructure investment, we find that the benefits of DRM are around 2.4 times costs.

Notwithstanding this, we suggest that generally cost/benefit analysis should only play a small part in the decision on whether to develop a DRM. Both benefits and cost are impossible to predict with certainty. In addition, retailers are likely to be in the best position to estimate costs, but have an incentive to find expensive ways to implement policies they don't like. As such, cost projections can be expected to be asymmetric, and policy makers are in a poor position to account for this asymmetry.

Finally, on Seed's analysis, they noted that demand projections are now much lower than when Frontier Economics assessed the benefits of DRM (on which Seed had relied). Therefore, Seed argued, benefits are likely to be much lower. We think Seed has made too much of this by focussing only on the demand-side of the market. On the supply side there have been several generator closures and mothballing and more can be expected in future. The relevant issue is the balance between supply and demand, not just demand. Taking account of this we are not convinced that benefits need be any lower than Frontier had projected. Furthermore, in the assessment of long-lived infrastructure investments, such as those needed to implement DRM, placing undue weight on near-term conditions would to be to err.

What has been the experience in the various electricity markets in the United States, where significant progress in DRM has been made?

Firstly, none of the U.S. DRM schemes (as applicable to larger energy users) are comparable to the AEMC's proposal. Only ERCOT has an energy-only market roughly comparable to the NEM. The most comparable program is NYISO's Day-Ahead Demand Response Program, but that is in a market that compensates separately for energy produced and capacity available and so calculation of energy market compensation can not be compared to that in the NEM. In short therefore, there is no scheme that can be directly compared to the AEMC's proposals and whose performance could therefore be used to help to assess outcomes in Australia. While that might seem to undermine the relevance of the U.S. experience, several powerful and relevant observations may be drawn from the U.S. experience:

1. The Congress of the United States and regulators at a federal and state level have long been avid supporters of demand response in many forms. They have persevered in its pursuit, despite generally on-going opposition from electricity suppliers;
2. Price-responsive demand response has taken many forms from direct procurement by the system operators though tenders and auctions (e.g. ERCOT) to day-ahead participation in wholesale markets (NYISO and MISO), to capacity market payments (NYISO, PJM, CAISO) to regulated programs applicable to vertically-integrated utilities (MISO, CAISO).
3. Emergency or reliability-based demand response programs appear to have been particularly successful.
4. Demand-response in Texas in 2008 and in PJM in 2013 seems have been remarkably successful in helping to address expected shortfalls at times of system peak demand.

Though the details differ significantly amongst the various U.S. markets, the common underlying demand response objective – encouraging energy users to reduce their demand from what it otherwise would have been when supply relative to demand is tight – has been and continues to be actively pursued. At the very least we might conclude from this that the U.S. experience is strongly supportive of price-based demand response even if it is unable to provide insight into the details of the best way to do this in Australia.

What do energy users think about DRM ?

The Energy Users Association of Australia arranged consultation sessions with its members, during the preparation of this report. To this end we met with representatives from energy users in resources, hospitality, real estate, metallurgy, food processing and manufacturing. Some electricity retailers, consultants and data service providers also participated.

We found that energy users were quite distant from the detail of the AEMC's proposals. Many expressed exasperation at what they perceived to be an esoteric regulatory debate that has dragged on for so long with so little evidence of progress.

Their experience was that their retailers had shown little interest in selling demand response to them, and the few offers that were available were not sufficiently attractive to entice them.

Users favoured allowing other market participants, besides retailers, the opportunity to market demand response to them (and hence supported the establishment of a DRM). However there was little clarity on what this might actually mean for them and whether sufficiently attractive demand response offers might be made in future.

These observations seem entirely consistent with the data, which shows very low penetration of wholesale market price-responsive demand in the NEM.

Conclusion

According to the ERAA, the development of a DRM mechanism such as the AEMC has recommended will cost retailers (and hence energy users) $45m to develop and another $10m a year to operate. The ERAA says that the costs are much greater than the benefits. But a plausible assessment of the benefits suggests that they have under-estimated them by a factor of 10, and even if we accept their cost estimates, benefits are still around 2.4 times costs.

There is good evidence that users would benefit if their prices were more closely related to the wholesale market, but that the penetration of wholesale market responsive demand remains miniscule, more than 15 years since the wholesale market started.

There is also good evidence of the widespread and increasing adoption of demand-response in the United States following long standing support from the Congress, federal and state regulators and energy users, and despite opposition from many electricity suppliers.

Bringing this evidence together we conclude that energy users' interests are likely to be served by the development of a DRM, as the AEMC has recommended. Expeditious implementation of the arrangements developed by AEMO would seem to be sensible.

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1 Introduction and background

This document is a report to the Energy Users Association of Australia. It examines the case for and against a demand response mechanism (DRM) to enable energy users to particulate in the wholesale electricity market. This report examines whether DRM will be beneficial to energy users. It also examines experience in the United States of America, and reviews a critique of the Australian Energy Markets Commission (AEMC's) recommendation in favour of DRM, that had been undertaken by a consultant for the Energy Retailers Association and National Generators Forum. That consultant recommended unequivocally that the AEMC's recommendation was flawed, and that the benefits of DRM fell far short of its costs.

Context

In November 2012, following a multi-year review, the AEMC recommended several changes in its Power of Choice Review. A key recommendation related to demand-side participation in the NEM. In particular, the AEMC recommended that AEMO be asked to develop a rule change proposal to establish a new demand response mechanism that would allow consumers, or third parties acting on consumers' behalf, to directly participate in the wholesale market and to receive the spot price for any reduction in their demand from what it would otherwise have been.

The AEMC concluded that this will enhance consumers' ability to participate in the wholesale electricity market by providing an alternative risk/reward mechanism to a spot price pass-through pricing option, thereby lowering consumers' information and transaction costs. They concluded that the mechanism will also provide a way of participating in the wholesale market that is separate from the retail energy contract and hence independent from the retailers' own commercial interests.

In the debate leading up to this decision, energy retailers generally opposed the AEMC's proposals while energy users (and the EUAA) were strongly supportive of the AEMC's proposals.

In 2013, following the AEMC's request, AEMO developed the necessary implementation arrangements. Energy users and others were consulted in the development of these arrangements. AEMO then prepared a rule change application which it was prepared to submit to AEMC by the end of 2013.

Before the Standing Council on Energy and Resources' December 2013 meeting, the Energy Retailers Association engaged with energy ministers suggesting that the proposed rule change not be considered. The ERAA's advocacy was supported by a report by Seed Advisory suggesting that the benefits of DRM would not exceed the costs of its implementation.

At its mid December 2013 meeting, SCER ministers decided that DRM should be deferred for further consideration by SCER officials. The EUAA foresaw the need for advocacy on the Demand Response Mechanism in its application to the Consumer Advocacy Panel for the 2013/14 financial year. The development of an effective DRM is

potentially of great benefit to energy users. This report seeks to provide an assessment of the issues from energy users' perspective, for consideration by SCER officials.

Layout of this report

There are two main sections to this report. The next section asks the question of whether DRM is worth implementing. The question is broken down into a number of smaller questions, which we answer in turn:

- What is DRM and what has been proposed ?
- Why not leave demand response to retailers?
- What is the market potential for DRM in Australia ?
- What cost/benefit analysis has been done?
- What did Seed Advisory conclude and are they right ?
- What weight should be placed on cost/benefit analysis ?

Section Three draws out relevant points to Australia, from the experience of DRM in the United States of America.

The final section (before the conclusion) explains the outcome of our consultation with Australian electricity users on their attitude to the implementation of a DRM.

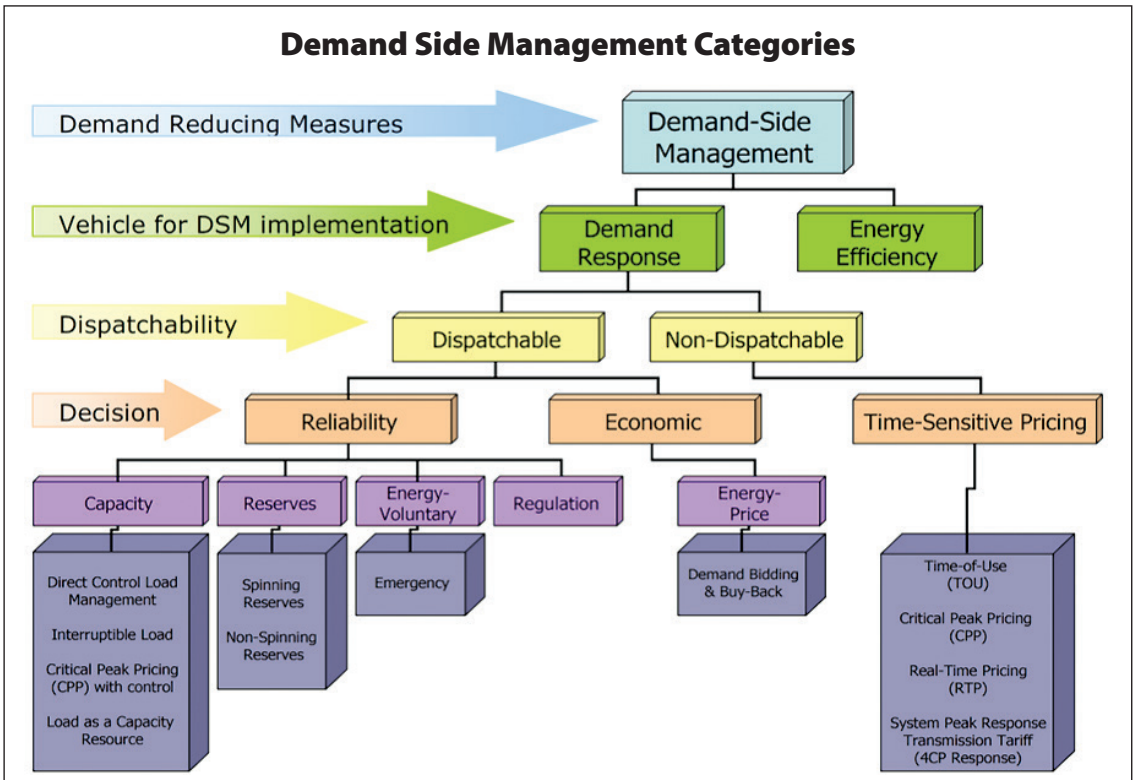
2 What is DRM and what has been proposed ?

The U.S. Department of Energy and the Federal Energy Regulatory Commission (Feurrigal and Neumann 2014) defines demand response as:

"Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized"

In the universe of demand side management possibilities, there are many taxonomies. A particularly descriptive taxonomy is discussed in (Synapse Energy Economics 2013) which in turn cites (North American Electric Reliability Corporation 2011), is shown in Figure 1 below.

Figure 1. Taxonomy of demand response possibilities



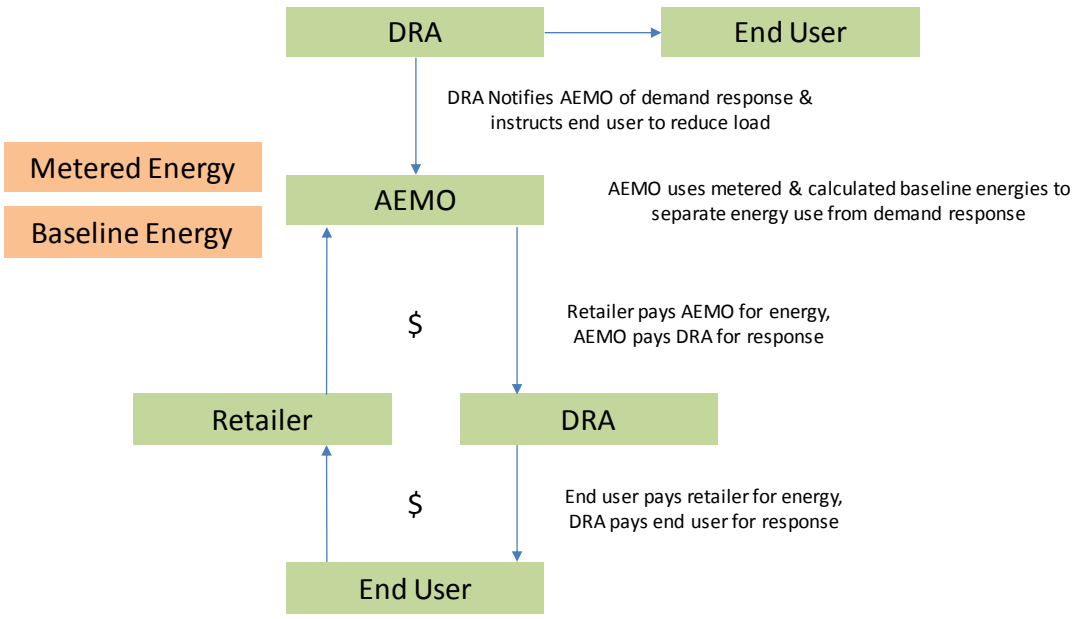
Source: (North American Electric Reliability Corporation 2011)

The Demand Response Management (DRM) proposal proposed by the AEMC and developed by AEMO fits most closely into the box in Figure 1, labelled "Demand Bidding and Buy-Back" under the Energy Price and Economic sub-categories (although the proposed arrangements in Australia are not intending (initially) to be dispatched.

The DRM is targeted at end-users of electricity that consume at least 100 MWh per annum. These users will be able to participate indirectly through a registered Demand Response Aggregator (DRA) or directly by registering as a DRA.

A DRA will be a registered participant in the NEM. In addition to businesses whose main business is demand aggregation, retailers, generators and possibly also network service providers will be able to register as a DRA. A summary of the commercial arrangements, as described by AEMO (Australian Energy Market Operator 2013) are shown in Figure 2.

Figure 2. Description of principle transactions



The main steps in the calculation of the amount of demand response are as follows:

- Step 1. A DRA notifies AEMO of an imminent or commenced load reduction. This creates a Demand Response Interval (DRI).
- Step 2. In analysis of settlement payments after the event, AEMO calculates the baseline consumption for the DRA for this interval, reflecting what demand is expected to have been had there been no demand response.
- Step 3. The baseline consumption is compared with actual energy consumption and the difference is attributed to demand response in that DRI.

The financial flows for each DRI can be summarised as follows:

- For each DRI, DRAs will be paid at the NEM regional reference node price for the difference between baseline consumption and actual consumption, adjusted for distribution and transmission losses as for other load. This may mean that DRAs will be charged if actual consumption exceeds baseline consumption.

- End users will be paid by the DRA for their demand reductions depending on the commercial arrangements they have negotiated with their DRA.
- Retailers will be charged by AEMO for their energy consumption at the NEM regional reference price based on the baseline consumption, adjusted for losses.
- End users will be charged by their retailer (at their particular retail rate) based on their baseline consumption.

It is proposed that the DRM arrangements will only employ meters with a National Metering Identifier (NMI). This would exclude customers and meters that are not visible or registered in the NEM systems (i.e. sub-meters).

The introduction of DRM will require changes to metering arrangements so as to support baseline calculations and settlement; provide for information exchange and notifications of changes in equipment or responsible entities. DRAs will be subject to the NEM's prudential requirements.

The DRM proposed in Australia is for demand response that participates in the NEM in the sense that it is exposed to the spot price at regional reference nodes. However Demand response will be non-scheduled (in other words not dispatched by AEMO) at the commencement of the DRM. This means that the demand response will not be taken into account in the calculation of the regional reference node prices in each five-minute trading period. This does not mean that DRM will not influence settlement prices. Specifically, during any half-hour settlement period if demand in reduced in five minute trading intervals in response to high prices in earlier trading intervals, demand response will affect the price in those five minute trading intervals and hence the settlement price for the six five-minute trading intervals that make up the price for the settlement period.

3 Why not leave demand response to retailers?

Energy retails are able encourage their customers to respond to high wholesale prices, by making available pricing arrangements that allow their customers to be exposed to wholesale prices. In this way, demand response can be left to retailers to achieve. A fundamental question to consider is therefore why, if at all, an additional mechanism is needed to promote demand response.

Electricity retailers in the AEMC's review and subsequently during AEMO's business model development argued that there was no need to create a demand response mechanism because they had the incentive and ability to expose their customers to wholesale prices and thereby achieve price-responsive demand. It follows from this argument that creating arrangements (and incurring costs in so doing) to allow DRAs to procure demand response would be unnecessary and wasteful.

Prima facie this argument is convincing: why would retailers not take advantage of their customers' ability to respond to high wholesale market prices? Indeed there is evidence of this amongst the very largest energy users. The counter response to this argument (see particularly submissions by ENERNoC to the Power of Choice review) is that bundling of the provision of demand response and electricity retailing inhibits the uptake of demand response, and that there is evidence of this.

The unbundling argument has a few key strands:

1. The value of demand response to most commercial and industrial energy users is likely to be small relative to the value they derive from more competitive retail offers. By implication, the bundling of demand response with the retail offer may lead to under-provision of demand response.
2. Retailers – who mostly also own generators – are likely to prefer to sell electricity to sustain the value of their generation assets, rather than find ways for their consumers to buy less electricity.
3. Successful provision of demand response requires expertise that is not core business in electricity retailing. It is necessary to understand the customer's loads and behaviour, identify which specific bits of plant can be curtailed, and then persuade the customer's operational staff that it's a good idea. Successful delivery then requires expertise in telemetry, remote control, testing, and a means of maintaining an ongoing relationship.
4. The successful sale and implementation of demand response is resource and potentially capital intensive. But retail contracts are typically 2-3 years. This limited duration means that bundling demand response with retailing is likely to diminish the potential market since short duration contracts require short payback periods.
5. From a retailers' perspective demand response may be a substitute for hedges obtainable in the financial market.

These are arguments, but what is the evidence? The next two sub-sections focus on whether consumers *can* benefit from demand reduction when wholesale prices are very high and then it examines whether consumers *do* obtain such benefit.

3.1 Can users benefit by reducing demand when wholesale prices are high?

By analysing half-hourly spot price data in the NEM it is possible to calculate the extent to which consumers should be able to reduce their average prices, by reducing demand in the highest price periods. Table 1 below which shows the average of the demand-weighted average spot prices in all NEM regions between 2007 and 2013 in the first data row. The second row shows the average of the demand-weighted average spot prices between 2007 and 2013 if the highest priced 72 settlement periods in each year are excluded from the calculation of average prices (in the second data row).

The difference between these two rows (in the third data row) shows the decrease in average annual prices that energy users could achieve if they reduced consumption at during the 72 highest price half hours. This shows a high of $25/MWh in South Australia and a low of $5/MWh in Tasmania. This means, for example, that for every unit of consumption that an energy user decreased their consumption during extreme price periods, they would be able to achieve a reduction in their average annual average price of electricity by $25/MWh. These are averages over seven years. if we examine the annual data we find significant variation. For example in South Australia in 2008 and 2009, energy users would have been able to reduce their average annual price of electricity by $53/MWh by reducing consumption in the 72 highest price half-hours.

Table 1. Average reduction (2007 to 2013) in average annual electricity prices if energy users reduced demand in the highest priced 72 half hours in each year.

	Victoria	NSW	QLD	TAS	SA
Demand-weighted average spot price ($/MWh)	$47	$50	$49	$45	$67
Demand-weighted average price excluding highest price 72 settlement periods ($/MWh)	$39	$40	$39	$40	$43
Decrease in average annual price if consumption reduced in highest price 72 settlement periods ($/MWh)	$8	$10	$9	$5	$25

The NEM has extremely volatile electricity prices and spot prices that reach peaks that are far higher than those in any other electricity market internationally (Mountain 2013). The annual price duration curve in NEM regions is therefore generally extremely steep, and this strongly suggests that there is benefit to be had for users that respond to extreme prices. Indeed, it was this price responsiveness that was one of the underlying objectives in the choice of the NEM as an energy-only market with very high market price caps.

3.2 Do users benefit by reducing demand when wholesale prices are high?

Having established that there is likely to be significant benefit for users in being responsive to extreme prices, we now to turn to the question of whether they are realising this benefit, As far as we are aware, there are only four energy users that are registered as market participants in the NEM. Of these four, two are for sales to very large end users that also have ownership of and contractual relationship with major generating plant that is linked to their demand. This leaves just two "pure" end users that are registered as market participants in the NEM.

There are some other energy users - mostly very large but also some smaller but highly sophisticated - that have electricity prices that are somewhat directly linked to spot price-based contracts. However we understand that even those customers that are able to choose wholesale-market linked contracts often also select some level of hedging to reduce their exposure to possible extreme prices. In this way, even many "spot exposed" contracts in fact do not necessarily provide strong incentives to reduce demand when wholesale market prices are very high.

As regards retail contracts that involve some form of compensation for demand reduction in response to extreme prices, the ERAA surveyed its members the headline outcome of which was mentioned, but not assessed, in the Seed Advisory report. This survey suggested that ERAA members have, in aggregate, around 215 MW of demand-response contracts of which around 50%, is related to embedded generation. This leaves around 100 MW of price-related demand response that does not involve embedded generation. Expressed as a quotient of the NEM simultaneous peak demand (circa 35 GW), just 0.3% of NEM peak demand is provided through contracts that involve some form of demand response.

Another assessment of the amount of load that is responsive to prices is contained in AEMO's 2013/14 National Electricity Forecasting Report[1]. This analysis – which includes demand response by all industrial and small energy users estimated a NEM-wide peak annual demand response of 412 MW[2]. Only a part of this – undisclosed in AEMO's report - would be demand response achieved through contracts offered by retailers.

We can compare this evidence of the actual penetration of demand-responsive load, with evidence on the market potential (see Section 2.3), and also evidence on experience in the United States (see Section 4):

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[1] See Chapter 7 of AEMO's 2013 Forecasting Methodology Information Paper for a description of AEMO's methodology.

[2] AEMO produce even higher numbers of demand-responsive load when wholesale prices are at the market price cap, but they say that these numbers can not be relied upon.

[3] In his paper "RPI-X, competition as a rivalrous discovery process, and customer engagement" prepared for the Conference "The Benefits of Utility Regulation" Model Review Competition and

[2] AEMO produce even higher numbers of demand-responsive load when wholesale prices are at the market price cap, but they say that these numbers can not be relied upon.

- Market potential in the industrial sector alone is around 3.7 GW or a little over 10% of NEM peak demand;
- Experience in North America suggests (on average) 6% of peak demand in the various markets is responsive to prices in wholesale markets.

3.3 Conclusion

It is difficult to be certain on the extent of demand in the NEM that is currently responsive to wholesale prices, but the evidence seems to be as follows:

- There are only two "pure" end users that are registered market participants in the NEM.
- Some retailers are known to offer electricity contracts linked to spot markets, but we understand they are generally reluctant to do this, since it offers brokerage fees rather than retailing margins. Some second tier retailers – such as Progressive Green – and more recently Macquarie Bank are apparently specialising in offering spot-linked contracts. However it remains a niche business and even where spot linked contracts are offered we understand that some level of hedging of extreme prices is also incorporated. This undermines the incentive to reduce demand at the times most valued in the market.
- Both AEMO and the ERAA report limited levels of wholesale market price—responsive demand.

The conclusion we draw from the argument and evidence is that the volume of demand that is responsive to wholesale prices is in fact small despite apparently significant benefits for energy users that reduce their demand when prices are high.

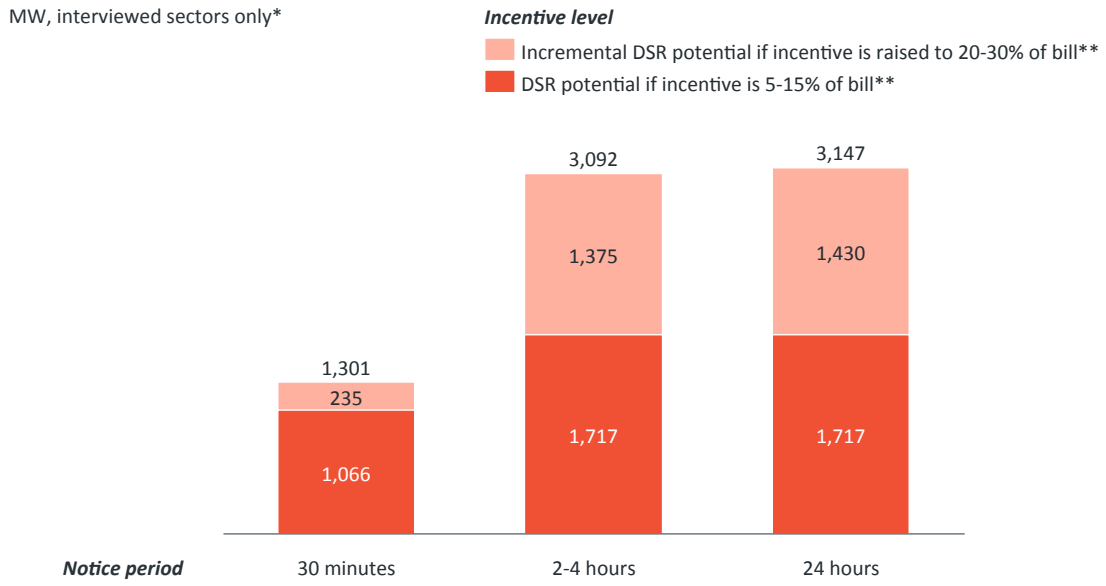
4 Cost/benefit analysis

4.1 What is the market potential for DRM in Australia ?

The AEMC concluded that DRM has the potential to capture from 2,100 MW – 2,800 MW of demand response from commercial and industrial energy. They calculated this estimate assuming "six to eight per cent of the total 35,000MW of (NEM) peak demand" and referred to "existing available studies and international experience" for this estimate (AEMC 2012).

Climateworks (ClimateWorks Australia 2014) recently produced an assessment of the market potential for demand response in the industrial sector, based on interviews and database interpolation. That report concluded that the technical potential for demand response from the industrial sector in Australia is 3.7 GW. The economically serviceable market potential would depend on the size of the discount and the notice period as shown in Figure 3.

Figure 3. DSR potential by notice period and incentive level



* Sectors covered by interviews make up 83% of Australian industrial electricity use
** Incentive is percent of total bill (network + usage) for MW made available for DSR whether or not used

Source: (ClimateWorks Australia 2014)

4.2 What cost/benefit analysis has been done of the proposed DRM?

4.2.1 Benefits

The main work that has been done on the benefits of demand response is contained in a presentation by Frontier Economics, that was presented at a public forum hosted by the AEMC on 3 October 2012. From this we observe that Frontier forecast that the energy

benefits of DRM ranged between annual dissaving of $5m for the lower case for 2014 to an annual saving of $245m in 2030 in the upper case. These benefit estimates covered all forms of demand response, not just benefits attributable to DRM for large energy users.

In its calculation of the benefits of DRM, Seed Advisory started with the Frontier estimate but then made various adjustments as follows:

1. They suggested DRM does not produce any network benefits and so they put zero value on this.
2. They increased total benefits for Frontier's lower case by $140m and for their upper case by $180m assuming no emission price (Frontier had assumed carbon costs).
3. They reduced the total benefits on the basis that demand response by households and energy efficiency account for about 40% of the total benefit, and so the remaining 60% is applicable to DRM applied to large energy users.
4. They reduced the benefits by $6m to $12m because Frontier Economics had apparently over-estimated the rate of uptake of DRM (an error recognized by the AEMC and dealt with in the AEMC's final report).
5. They suggested that the lower estimate used by Frontier should be preferred because "other unquantified adjustments discussed in Section 3 are likely to have a more material effect on the benefits estimates than changes to the treatment of carbon emissions". The main "unquantified adjustment discussed in Section 3" relates to expectations of lower demand in future compared to what Frontier had assumed in their analysis.
6. They truncated the forward projections to cover just the next 10 years (on the basis that the numbers beyond 10 years are too uncertain) and discounted the resulting 10 years of benefit at 7.1% to produce upper and lower estimates.
7. The outcome of Seed's analysis is an energy market-only benefit of DRM for commercial and industrial customers, stated as a net present value, of $38m-$42m.

4.2.2 Costs

AEMO developed a questionnaire on DRM costs under five headings: registrations; metering and data management; settlements and prudentials; retail customer billing and reporting. Retailers were asked to report on whether they thought the development and subsequent on-going costs they were likely to incur as a result of the proposed DRM scheme would be small, medium, large, very large or very very large (up to $100k, greater than $100k, up to $500k, greater than $500k, up to $2m, greater than $2m, up to $5m or greater than $5m). The Energy Retailers Association of Australia has the retailers' responses to this data request. Seed Advisory analysed these data and developed an estimated total cost, stated as a present value as discussed below.

4.3 What did Seed Advisory conclude and are they right ?

Seed concluded that the benefits of DRM did not exceed its costs. Seed's analysis of benefits is set out in Section 4.2.1. We discussed their analysis with them to understand

details not provided in their report. Following this review we conclude that their adjustments for carbon prices and distinguishing DRM benefits for large energy versus residential and other small energy users seems reasonable, as does their adjustment to take account of the apparent error in Frontier's presentation. The two main areas where we disagree with Seed, is in respect to the discount rate they chose (7.1% real) and the time horizon for the calculation of benefits (10 years). This affects the calculation of both benefits and costs. In this sub-section we focus on these. At the end of this subsection we address various other concerns we have with Seed's analysis.

4.3.1 Discount rate

Seed did not justify their discount rate beyond observing that it was apparently the same rate the AEMC had used. The rate (7.1%, post tax real) can be considered to be around the level of expected as a post-tax return on assets for private investment assets that provide services in competitive markets.

However the DRM costs that are being discounted are most appropriately considered to be public investment – i.e. in the infrastructure needed to operate a market, not in the assets that compete in that market. The majority of the DRM implementation cost is likely to be incurred by retailers who will pass the cost on to consumers. Some of the cost will be incurred by AEMO who will in turn pass the cost on to market participants who will in turn pass it on to consumers. The incidence of the cost does not create a competitive advantage or source of profit for the entity that pays it directly (AEMO and retailers). The question therefore, is what rate should this investment in what is essentially public infrastructure be discounted.

The choice of an appropriate social discount rate for cost–benefit analysis of public infrastructure projects has long been a contentious issue and a subject of intense debate among economists. Economic efficiency requires that the social discount rate measures the marginal social opportunity cost of public funds. In a perfectly competitive world without market distortions, the market interest rate is the appropriate social discount rate. In the real world where markets are distorted, the market interest rate will no longer reflect the marginal social opportunity cost of public funds.

The Asian Development Bank (Asian Development Bank 2007) sets out an excellent survey of different ways of thinking about the appropriate discount rate, distinguishing in particular between the Social Rate of Time Preference (SRTP) and Social Opportunity Cost approaches (the former generally resulting in lower rates than the latter). It is beyond the scope of this report to cover this discussion or even attempt to précis it, but readers are referred to it should they wish to explore this in more detail.

The ADB notes that developed economies typically adopted a much lower discount rate than developing economies. The most recent estimates they provide for various countries include France 4% in 2005, Germany 3% in 2004, Norway 3.5% in 1998.

The UK government indicates in the "Green Book, Appraisal and Evaluation in Central Government" (HM Treasury 2003) that an SRTP of 3.5% should be used to discount future benefits and costs of public projects with a lifespan below 30 years.

In the United States the Congressional Budget Office and General Accounting Office recommends that the rate of marketable Treasury debt with maturity comparable to project span should be used. For thirty year projects, this means rates of 2-3%.

More recent evidence in the United Kingdom in 2010 is that the Department for Energy and Climate Change and Ofgem currently use discount rates of 3.5% (Bradley, Leach et al. 2013).

In Australia, Infrastructure Australia (Infrastructure Australia 2013) recommends that the Public Sector Comparator Discount Rate should be the nominal risk free rate which should be based upon a long-term government debt instrument. For 20-30 year bonds this would equate to rates of 3-4%.

Bringing this empirical and theoretical evidence together, we suggest that a more appropriate discount rate to use for discounting the costs and benefits of DRM will be in the range of 3-4%, not 7%.

4.3.2 Time horizon

Seed discounted benefits and costs over a period of 10 years. However there are compelling counter-arguments to truncating the calculation at 10 years:

1. Firstly for all the reasons discussed in Section 4.4 costs and benefits are highly uncertain. There is absolutely no reason to believe that that uncertainty results in an asymmetric over-estimate or under-estimate over time. There is also no reason to believe that that uncertainty is time dependent. It would be just as wrong to skip the first 10 years of costs and benefits (and only look at the next 10) as it would be to just focus on costs and benefits for the first 10 years.
2. In conventional cost/benefit analysis it is highly unusual to truncate the calculation of benefits of long-lived assets after such a short period. This is because costs are incurred upfront but benefits accrue over the life of the investment and so truncating the calculation of benefits so early after the investment has been made inevitably and incorrectly under-estimates the net benefits.
3. It will take time to develop the DRM market by deepening the pool of suppliers, signing-up customers, implementing technology and so on. This is why the AEMC only expects full delivery of the benefits of DRM about 10 years after the systems are developed. Truncating the cost benefit analysis at just 10 years therefore excludes the substantial mass of benefits from evaluation.

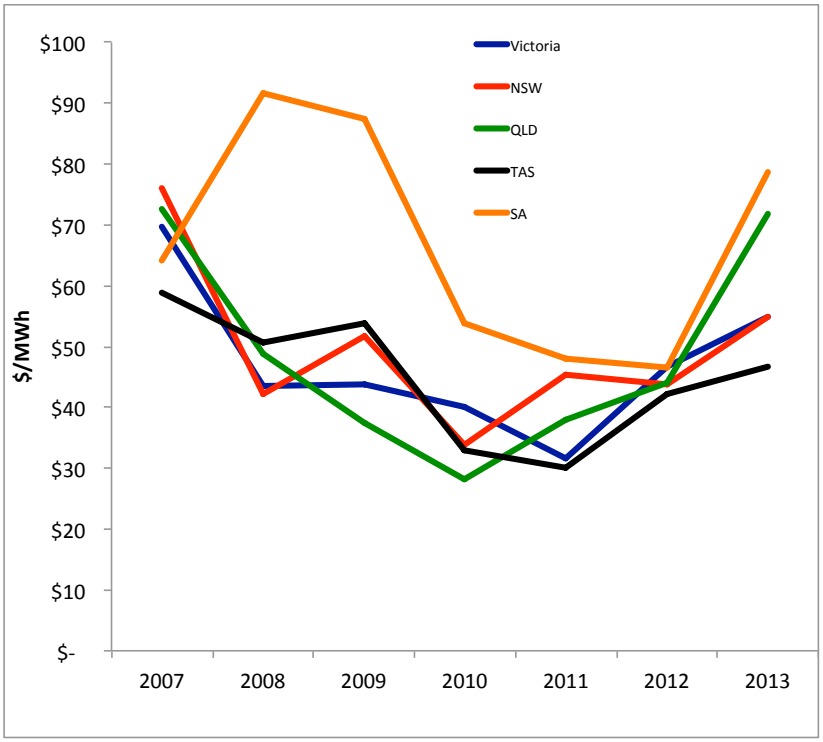
For these reasons we suggest that the time horizon for the cost/benefit analysis be extended to 2032, the end of the period modelled by Frontier Economics. Some allowance for the terminal value at the end of this period should also be considered for inclusion.

4.3.3 Costs

4.3.4 Other issues

One remaining concern with Seed's analysis merits discussion. Specifically, Seed suggest that Frontier's analysis has ignored the decline in demand in the National Electricity Market in AEMO's latest forecasting report. They suggest that taking account of this would reduce the benefits of DRM. This is not entirely implausible but we suggest Seed has made too much of it, to argue, as they have that Frontier's analysis has over-estimated benefits. Focussing only on demand (as Seed has done) is as wrong as focussing only on supply. A consideration of the value of DRM should be on the balance between demand and supply. Demand has indeed been declining in the NEM, however at the same time in response to declining demand there has been significant capacity withdrawals through closure and mothballing. This has helped to narrow the otherwise widening gap between demand and supply. While it is true that spot market volatility in the last couple of years has been less than in previous years, spot prices remain high (as shown in Fig 4 below) and it is not yet clear what effect the withdrawal of emission prices will have.

Figure 4. Demand-weighted average spot prices



Finally, as a matter of principle in the evaluation of long lived policy it is inappropriate to place undue weight on short-term market fluctuations: the existence of a possibly wider gap in the short term between supply and demand, should have little weight in the consideration of polices whose impacts will be long-lived.

4.3.5 What would the costs and benefits be if we took account of these issues?

Benefits

We recalculated the benefits using Frontier's forecasts to 2032 and we adjusted them for the absence of emission prices and to separate the demand-side benefits applicable to demand reductions attributable to a DRM mechanism application to large energy users, from those benefits applicable to energy efficiency programs and residential tariffs. We used exactly the same logic that Seed Advisory has used, and the AEMC gave us the same data that they had provided to Seed Advisory and so we were able to replicate Seed's calculation. From this analysis, before adjusting for the apparent error in Frontier's analysis we obtain an estimate of the benefits, stated as a present value, of between $464m and $473m.

To complete the calculation of estimated benefits we then need to adjust for the apparent error in Frontier's analysis. We have sought to replicate Seed's method. They explained approximately what they did but the calculation was not explained with sufficient clarity to allow its replication. Seed estimated $6-$12m to fix the error, but said it would be larger to take account of the longer period included in our PV calculation. We have doubled Seed's $12m upper limited and have assumed $24m to account for the apparent error. Our estimates of the benefit, stated as a present value is therefore $440m to $449m. This compares to Seed's estimates of $36m to $42m.

Costs

We asked the Energy Retailers Association of Australia (ERAA) for the same data that they had provided to Seed Advisory in order for Seed to undertake their assessment of the costs. In response, the ERAA provided aggregate data of once-off and on-going costs under five categories, stated as a present values in total for the three first tier and six second tier retailers that provided data to the ERAA. This was a more aggregated dataset than what the ERAA provided to Seed and thus we are unable to replicate Seed's calculation or critique the cost estimates that they used (or indeed see the costs estimates of the nine retailers – whose identity we were happy not to be informed about).

Nonetheless, knowing the ERAA's estimate of the total once-off and on-going costs, we were able to then calculate the present value of these using our recommended discount rate for the 19 year period. On this basis the present value of retailer costs (excluding AEMO's) is $172m. This compares to Seed's estimate of $112m.

AEMO's estimated costs (stated as a present value over 19 years) are between $11m and $18m.

Adding AEMO and retailer costs, we therefore get to a cost estimate of between $183m and $190m, stated as a present value.

Benefit/cost ratios

On the basis of our analysis – which replicates Seed's but for the discount rate (we used 4%, Seed used 7.1%) and term (we used 19 years, Seed used 10 years) – we calculate that expected benefits are between 2.4 and 2.6 times higher than expected costs. Seed concluded that expected benefits will be around 33% of costs.

The main reason for the big difference between Seed's and our conclusion is that Seed only examined costs and benefits for the first ten years. Most of the cost but only a small part of the expected benefits arise in those 10 years and so it can be no surprise that they conclude that benefits do not exceed cost.

We used 19 years, the longest period for which benefit projections are available (ideally cost/benefit analysis of market design investments such as these should be modelled over much longer periods).

The cost of capital we assumed also made a difference, but it is less important than discount period. If we were to have used Seed's assumed cost of capital, our calculation would be that benefits are 91% to 100% higher than costs, rather than 140%-160% higher than costs.

Finally, we would like to acknowledge the many helpful interactions with Seed Advisory in the course of our critique of their work.

4.4 What weight should be placed on cost/benefit analysis ?

In the previous sub-section we reviewed Seed's calculation of net benefit of DRM and concluded that after correcting what we considered to be errors in Seed's analysis, the conclusion is that benefits are substantially higher than costs. Having completed that forensic critique we now explain why we think that limited weight should be placed on cost/benefit analysis (including Seed's or our analysis) in deciding whether to proceed with DRM.

Dealing firstly with the calculation of benefits: The calculation of benefits relies on market modelling. Such modelling is inevitably a very unreliable prediction of the future. The electricity market is complex. Predicting its future outcomes requires many assumptions on demand, costs, technology selection and so on. A wide range of plausible assumptions can be made on all of these variables, and hence a wide range of plausible outcomes are possible.

But the assault on the validity of market modelling is not just about the uncertainty about input assumptions. It is also about the way that the market is assumed to operate. Frontier's model applies the familiar neo-classical concept of competition as a static state of equilibrium with price equal to the lowest cost of production, where demand and cost curves are taken as given. Other models try to account for different forms of competition. But there is a well-established body of theory that concludes markets are

unpredictable, that competition in markets is best described as a "rivalrous discovery process taking place over time".[3]

If the input assumptions are uncertain within a wide range, and competition in markets is beyond reasonable prediction, what reliance can reasonably be placed on market modelling ?

In the case of the calculation of DRM benefits there are additional problems beyond the underlying problem of predicting market outcomes. This is that specifying benefits associated with DR and then quantifying those benefits requires additional assumptions on the volume of responsive demand. Surveying the international literature on the financial and economic benefits of demand response, (Feurrigal and Neumann 2014) conclude "*quantifying the economic benefits still seems to be an open research question*".

Finally on the calculation of the benefits of DRM, there are many possible benefits that are so difficult to value because they are so uncertain (although their value is unlikely ever to be negative), that they are typically excluded in the calculation of benefits. This includes:

- Benefits associated with greater wholesale market competition, that demand response might stimulate;
- Benefits associated with the reduction in peak demand in helping to defer or permanently avoid the need for network augmentation;
- Benefits associated with energy efficiency improvements that may arise as a result of better knowledge about the way that energy is used.

Excluding benefits such as these introduce an asymmetric error: the stated benefit is likely to be best understood as an under-estimate, to the extent that it fails to take account of these uncertain, but possibly significant, benefits.

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[3] In his paper "RPI-X, competition as a rivalrous discovery process, and customer engagement" prepared for the Conference "The British Utility Regulation Model: Beyond Competition and Incentive Regulation?" held at the LSE on 31 March 2014, Stephen Littlechild points to key contributions to the concept of competition as a rivalrous process over time include JA Schumpeter, *Capitalism, Socialism and Democracy*, Harper & Row, 3rd edn, 1950 especially chapter VII "The process of creative destruction"; FA Hayek, "The Use of Knowledge in Society" *American Economic Review,* XXXV (4), 1945, 519-30, reprinted in Hayek, *Individualism and Economic Order*, Routledge and Kegan Paul, 1948; FA Hayek, "Competition as a Discovery Procedure" in FA Hayek, *New Studies in Philosophy, Politics, Economics and the History of Ideas*, University of Chicago Press, 1978; IM Kirzner, *Competition and Entrepreneurship*, Chicago University Press, 1973; IM Kirzner, "The Perils of Regulation: A Market Process Approach" in IM Kirzner, *Discovery and the Capitalist Process,* Chicago University Press, 1985; IM Kirzner, "Entrepreneurial Discovery and the Competitive Market Process: An Austrian Approach", *Journal of Economic Literature,* 35(1), 1997, 60-85. Another recent and accessible succinct exposition is in IM Kirzner, *How Markets Work: Disequilibrium, Entrepreneurship and Discovery*, Institute of Economic Affairs, Hobart Paper No 133, June 1997, available at www.iea.org.uk

In light of these comments, what should be made of the evidence that Frontier's benefit analysis had no supporting report, its assumptions were not stated, apparently significant errors were identified etc. as discussed in the previous section? Does this make their conclusion, and the AEMC's conclusion based on it any less valid. For the reasons set out in this sub-section we suggest not. The estimation of benefits should not ever be considered to be more accurate than within an order of magnitude. There do not appear to be any fundamental flaws in either Frontier's analysis or the AEMC's conclusions. Our advice is that policy makers and their advisors should not seek solace in benefit estimates. It is just one element of evidence to be weighed and spurious accuracy in benefit estimation is misplaced time and effort and risks focusing on the wrong thing.

Moving to the estimate of costs, this is less problematic than the calculation of benefits (the plausible range within which cost estimates may lie is likely to be narrower than the plausible range within which the benefits may lie). While the ERAA did, very kindly, provide the data necessary to allow us to replicate Seed's analysis, in aggregate, they did not provide the underlying cost data to us. It was not clear that confidentiality would be a valid issue, we were quite happy to accept the data on condition of retailer anonymity. It is a concern that the underlying data has not been made available. It means that a well-informed critique and peer review has not been possible. Inevitably, this lack of transparency seems to support a suggestion that retailers have something to hide and that the estimates that they have provided are likely to be higher than might reasonably be expected.

It is not clear that this problem can ever be meaningfully overcome: the parties most likely to know the costs of DRM implementation – the retailers – are also the parties most threatened by DRM and hence do not have an incentive to find the least expensive way to implement any necessary changes, or indeed to advance such information in cost / benefit assessments. Inevitably this will undermine the veracity of cost / benefit assessments.

5 Demand response programs in the United States

The United States Congress declared in 2005 that "*time-based pricing and other forms of demand response . . . shall be encouraged . . . and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated*". Since that time substantial progress has been made and the arrangements adopted in the various electricity markets in the United States provide useful evidence for the debate in Australia.

The Australian debate on demand response has often alluded to experience with demand response in the United States, but the description and detail has been relatively superficial. It is valuable to understand the experience in United States in more detail in drawing informed drawing conclusions on the benefits and costs of developing demand response in the National Electricity Market. Appendix A reviews this material.

What can be said of the U.S. experience that is relevant to debate on whether to proceed with the proposal recommended by AEMC and developed by AEMO? To start it is important to note that none of the U.S. schemes are comparable to the AEMC's proposal. Only ERCOT has an energy-only market roughly comparable to the NEM. The most comparable program is NYISO's Day-Ahead Demand Response Program, but that is in a market that compensates separately for energy produced and capacity available and so calculation of energy market compensation can not be compared to that in the NEM. In short therefore, there is no scheme that can be directly compared to the AEMC's proposals and whose performance could therefore be used to help to assess outcomes in Australia. Nonetheless, several powerful and relevant observations may be drawn from the U.S. experience:

1. The Congress of the United States and regulators at the federal and state levels have long been avid supporters of demand response in many forms. They have persevered in its pursuit, despite generally on-going opposition from electricity suppliers;
2. Demand response has taken many forms from direct procurement by the system operators though tenders and auctions (e.g. ERCOT) to day-ahead participation in wholesale markets (NYISO, ISO-NE, MISO), to capacity market payments (NYISO, ISO-NE, PJM, CAISO) to regulated programs applicable to vertically-integrated utilities (California, New York and the midwest).
3. Emergency or reliability-based demand response programs appear to have been particularly successful.
4. Demand-response in Texas in 2008 and in PJM in 2013 seems have been remarkably successful in helping to address expected shortfalls at times of system peak demand.

Though the details differ significantly amongst the various U.S. markets, the common underlying demand response objective – encouraging energy users to reduce their demand from what it otherwise would have been when supply relative to demand is tight – has been and continues to be actively pursued. At the very least we might conclude from this that the U.S. experience is strongly supportive of price-based

demand response even if it is unable to provide insight into the details of the best way to do this in Australia.

6 Australian energy users' experience with DRM

The Energy Users Association of Australia arranged consultation sessions with its members, during the preparation of this report. To this end we met with representatives from energy users in resources, hospitality, real estate, metallurgy, food processing and manufacturing. Some electricity retailers, consultants and data service providers also participated.

A few observations from these consultations were as follows:

- Most energy users, even the largest, had little understanding of the detailed design of proposed DRM scheme and how it might affect them.
- Many energy users had been in active discussions with their retailers and some other market participants on compensation for demand response, but offers were not sufficiently attractive to stimulate their uptake.
- Some energy users have experience with demand management offered by existing Australian energy retailers, who have in turn contracted other service providers to provide systems and expertise to deliver on the offers.
- Some energy users in Victoria have had some experience with network-based demand-side programs and have reported mixed experiences on this.
- Most energy users seemed to strongly support the unbundling of demand management from electricity retailing on the basis that this would enable other market participants to compete to provide demand management services to them. However, almost all participants suggested that demand management service providers would need to make more enticing propositions to secure their business.
- Generally there seemed to be a reasonably high degree of reticence about demand management; that there had been limited or no evidence that their retailers had pursued this, and that it was not clear to them that there were market opportunities in this area.

Following the consultation with Australian energy users, one of the EUAA's members arranged a teleconference with their colleagues in Ohio, whose company had taken up a demand management option provided by its regulated utility. ENERNoC had been contracted by the utility to secure demand management contracts, pursuant to regulatory controls on the utility. The contracts involved a combination of performance and availability fees, and participation was voluntary. The program has been in place for that energy user for the last three years and the revenues had risen by an order of magnitude each year. The energy user found that at first their company was reticent and sceptical about the scope for demand management, but following the implementation of the scheme various innovations and changes in operating practices had revealed increasing scope to reduce and shift load. They were pleased to be able to participate in the scheme for the benefits it provided to them, and the sense that they were able to provide a benefit that other energy users would share by avoiding expansion of generation and transmission capacity.

7 Conclusions

According to the ERAA, the development of a DRM mechanism such as the AEMC has recommended will cost retailers (and hence energy users) $45m to develop and another $10m a year to operate. The ERAA says that the costs are much greater than the benefits. But a plausible assessment of the benefits suggest they have under-estimated them by a factor of 10, and even if we accept their cost estimates, benefits are still around 2.4 times costs.

There is good evidence that users would benefit if their prices were more closely related to the wholesale market, but that the penetration wholesale market responsive demand remains miniscule, more than 15 years since the wholesale market started.

There is also good evidence of the widespread and increasing adoption of demand-response in the United States following long standing support from the Congress, federal and state regulators and energy users, and despite opposition from many electricity suppliers.

Bringing these factors together we conclude that energy users' interests are likely to be served by the development of a DRM, as the AEMC has recommended. Expeditious implementation of the arrangements developed by AEMO would seem to be sensible.

Appendix A: Demand response programs in the United States

7.1 Demand response in regional markets

Over the last decade demand response programs have been steadily integrated into wholesale electricity markets in the United States. There has been long-standing support for demand-side participation in many parts of North America and in 2005 the Congress declared (United States Court of Appeals 2014) that

"*the policy of the United States that time-based pricing and other forms of demand response . . . shall be encouraged . . . and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated*."

Demand response markets are operated by Regional Transmission Organisations (RTOs) and Independent System Operators (ISOs) in different areas in the U.S. The main demand response programs in the United States are managed by the following entities:

- New York Independent System Operator (NYISO)
- ISO New England, Inc. (ISO-NE) (*replaced NEPOOL in 1997)
- PJM Interconnection, LLC (PJM)
- Midcontinent Independent System Operator (MISO)
- Electric Reliability Council of Texas (ERCOT)
- Southwest Power Pool, Inc. (SPP)
- California Independent System Operator (CAISO)

Since 2001, the Federal Energy Regulatory Commission (FERC) has required ISO/RTOs to file annual program evaluations or include a detailed discussion of their demand response enrolment and performance in annual state of the market reports. FERC also conducts biennial surveys of demand resources in the United States.

A recent staff report (FERC 2013) shows the volume of demand response, and expressed in proportion to regional peak demand. This is shown in Figure 5 below:

Figure 5. Demand response potential and resources at U.S. ISOs and RTOs.

RTO/ISO	2011 Demand Response (MW)	2011 Percent of Peak Demand[9]	2012 Demand Response (MW)	2012 Percent of Peak Demand[9]
California ISO (CAISO)	2,270 [1]	5.0%	2,430 [1]	5.2%
Electric Reliability Council of Texas (ERCOT)	1,570 [2]	2.3%	1,750 [3]	2.6%
ISO New England, Inc. (ISO-NE)	1,231 [2]	4.4%	2,769 [4]	10.7%
Midcontinent Independent System Operator (MISO)	9,529 [2]	9.2%	7,197 [5]	7.3%
New York Independent System Operator (NYISO)	2,247 [2]	6.6%	1,888 [6]	5.8%
PJM Interconnection, LLC (PJM)	14,127 [2]	8.9%	10,825 [7]	7.0%
Southwest Power Pool, Inc. (SPP)	1,514 [2]	3.2%	1,444 [8]	3.1%
Total RTO/ISO	**32,488**	**6.7%**	**28,303**	**6.0%**

Source: (FERC 2013)

A variety of payment arrangements exist for compensation of demand response in wholesale markets (Federal Energy Regulatory Commission 2011). The programs focussed on economic demand response include:

- Following the implementation of FERC Order 745, PJM Interconnection pays economic demand response the full the Locational Marginal Price minus the generation and transmission portions of the retail rate.
- ISO New England Inc. (ISO-NE) and New York Independent System Operator, Inc. (NYISO) pay LMP when prices exceed a threshold level, with the levels differing between the RTOs.
- The Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO) demand response programs pay LMP for demand response resources in the day-ahead and real-time energy markets.
- The California Independent System Operator Corporation (CAISO) pays LMP at pricing nodes, or sub-load aggregation points (Sub-LAP) in its Proxy Demand Resource program that allows qualifying resources to provide day-ahead and real-time energy. CAISO also provides for demand response resources to participate in its Participating Load program, which enables certain resources to provide curtailable demand in the CAISO market. CAISO pays nodal real- time LMP for its Participating Load program.
- The Southwest Power Pool, Inc. (SPP) has filed revisions to its tariff to facilitate demand response in the Energy Imbalance Service Market.

7.1.1 PJM Interconnection

PJM is an RTO managing the distribution of wholesale electricity in the Mid-Atlantic region of the United States, across 13 states and the District of Columbia. PJM commenced its demand response programs in 1997 and it now has the largest total volume of demand response resource in the United States in emergency (9 901 MW) and economic (2,660 MW) demand response programs (PJM 2014) .

In 2001, PJM started to develop programs for customers to participate in energy markets directly, through a third-party curtailment service provider (CSP) or through their electricity suppliers. Today, PJM's main demand response program is a capacity market, the Reliability Pricing Model (RPM), which is designed to ensure enough resources - generation, energy efficiency and demand response - are available to meet demand for electricity at all times. The RPM allows DR to be bid as a forward capacity resource, whereby even resources deployed infrequently receive capacity payments in exchange for making electrical capacity available. Each year PJM conducts what it calls Base Residual Auctions to contract delivery of capacity over the next three years. The great majority of PJM's demand response resources are contracted through its Base Residual Auctions. Each demand response resource must be willing to reduce its demand for electricity for up to at least 10 times each year as required.

PJM's economic demand response program encourages resources to reduce consumption voluntarily in response to PJM's locational marginal prices (LMPs). Economic demand response participants receive payments based on day-ahead LMP for their reductions.

PJM started to permit demand response participation in ancillary services markets in 2006. PJM operates three ancillary services: synchronised reserves, which is the ability to reduce electricity consumption within 10 minutes of PJM dispatch); day-ahead scheduling reserves, the ability to reduce electricity consumption within 30 minutes of PJM dispatch; and regulation or the ability to follow PJM's regulation and frequency response signal.

Participation in PJM's economic demand response market is voluntary; however, once a bid is accepted, delivery is mandatory. During summer 2013, PJM activated record levels of emergency and economic demand response resources. In July 2013, PJM called capacity-based, emergency demand response resources for several of its zones, dispatching 652 MW on 15-16 July and 1,638 MW on 18 July. Economic demand response resources were also deployed. Hourly economic demand response reached levels of approximately 250 MW, 400 MW, 870 MW, 630 MW and 625 MW on each day, respectively, over 15-19 July 2013. On 11 September 2013 PJM requested and received its largest ever volume of demand response, approximately 5,949 MW. PJM's economic, voluntary demand response resources played a vital role in stabilising the power grid during the demand spikes in September 2013 (PJM 2014).

7.1.2 The New York Independent System Operator

The NYISO is a not-for-profit corporation that coordinates and monitors the operation of the electrical power system in New York State.

The NYISO established its first demand response program in 1999. The NYISO's demand response has expanded considerably since then. The NYISO operates emergency/reliability and economic demand response programs. The Emergency and Demand Response Program (EDRP) and the Installed Capacity Special Case Resources (ICAP/SCR) Program are the NYISO's reliability-based demand response programs. The core aim of EDRP and ICAP/SCR programs is to deploy registered demand response resources in energy shortage situations to maintain the reliability of the power

grid. These programs reduce power demand through load curtailment or behind-the-meter generation.

Currently, more than 90 percent of the 1.9 GW of demand response resources registered in NYISO are reliability demand response resources (EDRP and ICAP/SCR). (Potomac Economics 2013). In 2011, the EDRP and ICAP/SCR was capable of providing a total of 1,888.2 MW of demand response capability. The ICAP/SCR Program is the largest of the NYISO's demand response programs both in the volume of individual demand side resources and measured in total capacity.

The NYISO's economic demand response programs (i.e. when the resource decides when to participate and bids load curtailment into the wholesale power market) are the:

- Day-Ahead Demand Response Program (DADRP)
- Demand-Side Ancillary Service Program (DSASP)

The DADRP allows energy users to bid load reductions or 'negawatts' into the day-ahead market, just as generators bid power, and be paid at the clearing price. If the load curtailment bid is a less expensive alternative than a generator's day-ahead offer, it is accepted (the current offer floor price is US$75/MWh). NYISO clients registered with the DADRP nominate hours in the following day they are willing to reduce electricity use, in addition to the volume of that reduction. The DADRP allows flexible loads to increase supply in the market and thereby relieve spikes in the wholesale price. The DADRP is voluntary and demand response resources registered by the NYISO can nominate minimum and maximum run times and the hours that they can be made available. Participants are eligible for Bid Production Cost guarantee payments to make up for any differences seen between the spot market price received and their block offer. Any failure to curtail committed load results in the imposition of a fine. Participation in the DADRP has remained modest, under 10 MW, in recent years. In its most recent report to FERC on its demand side management programs, the NYISO stated that, during the analysis period of September 2011 through August 2012, there were no offers or schedules of DADRP resources (NYISO 2013).

The DSASP provides retail customers with a minimum 1MW resource, and which can meet telemetry and other technical requirements, with an opportunity to bid load curtailment capability into the day-ahead market and the real-time market. Scheduled offers are paid the market clearing price for spinning reserves or regulation. As in the DADRP, the energy offer floor price is currently $75/MWh.

7.1.3 The Electric Reliability Council of Texas

The Electric Reliability Council of Texas (ERCOT), a non-profit corporation, is responsible for managing 85 per cent of the Texas' electric load. ERCOT's customers can participate in emergency demand response through participating in its Emergency Response Service (ERS) or as Load Resources (LR). In 2012, around 2,400 MW of load were registered as resources.

ERS resources are called to alleviate emergency conditions on the ERCOT grid and can cater for individual loads or aggregated loads. All customer classes can participate. The

minimum offer is 100 kW. ERS resources are procured through requests-for-proposal for 4-month contract periods. Currently, 580 resources are registered, of which 156 are aggregations of multiple loads. The total capacity is 853 MW[4]. (ERCOT 2014)

The maximum total amount of ERS that can be procured for any period was capped at 1,000 MW by the Public Utility Commission, although that restriction has since been removed. Most participants are large industrial customers. Load Resources can respond using an under-frequency relay, or be dispatched through Energy Emergency Alerts issued by ERCOT. Most ERCOT demand response programs go into effect when reserves drop below 1,750 MW (FERC 2013) ERS resources are required to shed committed load volumes within either 10 or 30 minutes of receiving dispatch instructions and must maintain their load curtailment until the resource is released by ERCOT.

The most active participation has been in the day-ahead spinning reserve market, with Load Resources providing 50 per cent of spinning reserves (usually 1,150 MW) in most hours (The Brattle Group 2011). On 26 February 2008, through a combination of a sudden loss of thermal generation, a sudden drop in power supplied by wind generators and the unexpected ramping of demand, ERCOT faced a critical shortage of reserves. The system operator called on all demand response resources and 1,200 MW of demand-side resources responded rapidly, bringing ERCOT back into balance (Federal Energy Regulatory Commission 2011).

ERCOT's voluntary load demand response is an economic resource: it is not dispatched by or recorded by ERCOT. Voluntary resources are able to respond to dynamic pricing (ToU, critical peak, real-time) and/or load control. Load curtailment in anticipation of '4CP intervals' is also possible.[5]

Resource availability concerns following the summer of 2011 led to ERCOT and the Texas Public Utilities Commission to explore ways to increase demand-side participation. With this aim in mind, ERCOT introduced 30-minute response and weather sensitive options to ERS (as well as changing its name from the Emergency Interruptible Load Service).

The integration of wind output is also being progressed by ERCOT. Texas is the leading state in the United States in terms of total wind generating capacity. The rapid ramping of wind poses grid reliability challenges. As wind is a variable resource and wind ramps tend to coincide with load ramps, leading to net load effects (load minus wind power), load and wind power changes can occur in opposite directions, which requires

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[4] This is sourced from the Jun-Sep 2014 procurement results available from http://ercot.com/services/programs/load/eils/index

[5] 4CP is average coincident peak demand reading set by a user's electric load over the four-month period over June, July, August, September, the peak generating months in Texas. Each month will set a monthly demand peak. If a user's end use load is running at the same time that ERCOT sets its monthly demand peak, then it has contributed to the monthly '4CP' coincident peak.

adjustment by other generators. While the system load is still much larger than the actual production of wind power in ERCOT system, and load fluctuations dominate the overall net load fluctuations, the availability of demand response resources has assisted ERCOT in increasing wind penetration in Texas (Yin-Huei 2011).

7.1.4 California Independent System Operator (CAISO)

California's demand response has focussed mostly on having emergency resources available to respond to reduce peak demand and alleviate stress on transmission and distribution systems. California's Energy Action Plan (2003) and Energy Action Plan II (2005) contained a state-wide demand response goal of meeting 5 per cent of peak demand (California Energy Commission 2013). Progress against this goal is shown in Table 2 below.

Table 2 - California Demand Response, 2008-2013

	2008	**2009**	**2010**	**2011**	**2012**	**2013**
Target (MW)	2345	2302	2368	2277	2342	2371
Emergency	2007	2172	1544	1428	1010	924
Economic	1287	1095	539	814	1420	1046
Surplus/shortfall against target (MW)	949	965	-285	-35	88	-401

Source: (California Energy Commission 2013)

In September 2013, the California Public Utilities Commission (CPUC) issued an order to utilities requiring them to address their lack of participation in demand response. The CPUC has also developed demand response load impact and cost-effectiveness protocols to record load curtailment and assess demand response programs' effectiveness.

Recently, CAISO has developed two demand response programs: the Participating Load product and the Proxy Demand Resource product, both of which allow demand response resources to bid load curtailment into energy and non-spinning reserve markets.

The announcement by Southern California Edison in June 2013 that it would retire the San Onofre Nuclear Generating Station, and the addition of renewable generation to the state's grid has also added to the urgency for the expansion of California's demand response programs.

7.1.5 Midwest ISO

MISO manages the delivery of electric power across 15 states in the Midwest and to the Canadian province of Manitoba. MISO's Demand Response Resources (DRR) covers load- modifying, economic demand response and emergency demand response (Emergency Demand Response, EDR). Demand response is an important contributor to MISO's resource adequacy. The volume of demand response resources participating in ISO's economic and emergency programs increased from 400 MW in 2010 to 1,500 MW in 2012.

Table 3 - Demand Response Capability in MISO 2009–2012

	2009	2010	2011	2012
Midwest ISO				
Embedded generation (BTMG)	4,984	5,077	3,001	2,969
Load Modifying Resource (LMR)	4,860	3,184	2,898	2,882
DRR Type I	2,353	46	472	372
DRR Type II	111	0	75	71
Emergency DR	242	357	930	902
Emergency DR also counted as LMR	NA	NA	*404*	*380*
Total (MW)	**12,550**	**8,664**	**7,376**	**7,196**

Source: (Potomac Economics 2013)

In 2012, MISO had 7.2 GW of demand-response capability registered. The greater share of MISO's DR is interruptible, load-modifying resource developed under regulated utility programs, or it is BTMG, which MISO does not have control over, even under emergency conditions.

In 2011, MISO's total demand response capability was categorised broadly by MISO into Capacity Resources and Load Modifying Resources. The categories overlap. Capacity Resources are further distinguished by MISO between Demand Response Resource (DRR) Types 1 and 2, defined by MISO (see as (MISO 2011) follows:

- Type 1 - a resource hosted by a consumer or load-serving entity capable of supplying a specific quantity of energy or contingency reserve when it chooses to do so as a market participant to the energy and operating reserve market through physical load interruption; and

- Type 2 - a resource hosted by an energy consumer or load serving entity capable of supplying energy and/or operating reserve when it chooses to do so as a market participant to the energy and operating reserve market through BTMG or controllable load.

MISO's Load Modifying Resources covers demand resources (interruptible load or direct control load management); and BTMG. Under its definition, MISO's load modifying resources are also capable of providing emergency demand response.

Pure emergency demand response is classified by MISO not as resource type but a specific use in the form of the commitment and dispatch of load reductions, BTMG and other demand resources during an emergency.

DRR Types 1 and 2 are the only resources available as economic demand response in MISO markets, able to replace higher-priced energy offered by generators. The two types of DRR differ in the flexibility of their responses to dispatch instructions. Most participation in MISO's DRR to date has been through load interruption. Participation in the energy and ancillary services has been comparatively minor. Cleared DRR energy offers receive the same day-ahead or real-time price as generators. At the end of 2012, 443 MW had actually participated in MISO's energy markets as DRR (Potomac Economics 2013).

Emergency demand response resources submit costs to MISO for the reduction of load during an emergency event. EDR can change its offer and availability day-by-day. Although voluntary, once committed an EDR resource is then required to respond during an emergency. Resources that do not qualify as DRRs, or are not offered into the energy and spinning reserve markets can also offer to reduce their loads when MISO declares an energy emergency event. MISO requires its planning resources, which are paid for capacity, to make load curtailment available during emergency events.

7.2 FERC Order 745 and subsequent District Court Decision

While US wholesale markets have succeeded in the integration of demand response into market design and market operations over the last decade (as discussed in the previous section) there has been opposition to FERC's requirement that regional demand response programs must pay the full locational marginal price (LMP) to demand response bidders.

In March 2011, FERC issued Order No. 745 'Demand Response Compensation in Organized Wholesale Energy Markets,' (Federal Energy Regulatory Commission 2011) which set uniform compensation levels for suppliers of demand response resources participating in the day-ahead and real-time energy markets. The order directed ISOs and RTOs to pay those suppliers, including aggregators of retail customers, the full LMP. On 23 May 2014, the U.S. Court of Appeals for the District of Columbia struck down Order 745 (in response to an action filed against the Order by the Electric Power Supply Association (EPSA), American Public Power Association and other energy industry associations).

Critics of economic demand response have long argued that paying the full LMP amounts to overcompensation for load curtailment, because most demand response resources would not have purchased power directly in the wholesale market in the first place. American electricity suppliers, whose margins have been reduced through low retail prices and falling demand, consider LMP pricing for demand response to be too high. The sale of 'negawatts' does not reflect the marginal cost of power production, according to generators, so long as there is no cost to an energy consumer from curtailing consumption.

The EPSA's legal case, however, was framed in terms of states' rights, whereby Order 745 represented federal over-reach into states' jurisdictions. The EPSA's core argument was that FERC's authority under the *Federal Power Act* did not extend to mandating for payments to be made in the retail market. According to the EPSA, the Commission had no authority to encourage retail customers to trade in wholesale markets by paying them not to make retail purchases: retail sales of electricity were the exclusive jurisdiction of the States.

In Order 745, FERC wrote that, should retail consumers participate voluntarily in the wholesale market, they would fall within the Commission's exclusive jurisdiction to make rules for the operation of wholesale markets. The mandatory compensation of demand response resources would ensure the competitiveness of wholesale energy

markets and that reasonable wholesale rates would be paid to demand response resources. Payments of the full LMP to demand response providers did not constitute a subsidy for demand response any more than payments made to generators for the power that they sell in the wholesale market.

While the Court's ruling does not spell the end of U.S. economic demand response programs, it is expected to lead to reductions in payments made by ISOs and RTOs to economic demand response resources. Lower payments will discourage retail customers from investing in energy efficiency upgrades and equipment. Economic demand response programs will remain as a series of state-based programs with various design and payment arrangements. The overturning of Order 745 could also impede the integration of renewables, for instance where demand response has assisted in bringing wind and solar onto the grid.

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