SFS Economics

Economic implications of the proposed Demand Response Mechanism

Report for the Energy Supply Association of Australia and the National Generators Forum

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Summary

The Australian Energy Market Commission's Draft Report on the 'Power of Choice' (the Draft Report) recommends establishing a new demand response mechanism (DRM) that would enable participating customers to offer a demand response (DR) for which they would be paid at NEM spot prices. The level of a customer's DR would be determined with reference to a counterfactual 'baseline'.

We have been asked by the Energy Supply Association of Australia and the National Generators Forum to prepare an assessment of the economic implications of the proposed DRM. The purpose of this report is to assess any implications for economic efficiency and other economic effects that may potentially arise as a result of the proposal.

Implications of the DRM for consumers

The proposed DRM will not reduce wholesale and retail market prices as set out in the Draft Report. The DRM introduces a disconnect between the demand that must be hedged by retailers in the contract market (as reflected in the baselines of DR customers), and actual (metered) demand and therefore actual generation in the spot market. In the short run, generators contracted to meet baseline demand will therefore be exposed to greater financial risks from unfunded difference payments. However, financial (contract) markets adjust very quickly to changed distributions of risk, so that the prices of hedge contracts purchased by retailers will increase. These costs will be passed on to consumers in the form of higher retail prices. The overall economic effect of the DRM is that markets and prices will adjust to a new equilibrium in which the cost of (potentially very) high payments to commercial and industrial (C&I) customers participating in the DRM are transferred to consumers as a whole.

The proposed DRM is ultimately unsustainable, for reasons that are intuitively clear but complex to trace through. It offers potentially very large incentive payments to customers providing a DR that do not match the economic benefit of the DR. In dynamic markets, transfers that do not reflect the underlying value of a transaction will be unwound. In the case of the DRM, the cost to retailers of hedging spot market transactions on behalf of consumers will increase; that cost will ultimately be borne by consumers as a whole in the form of higher retail prices.

Because the proposed DRM would transfer the cost of paying for DR to consumers, it also raises equity concerns. If retail prices increase across the board, all consumers will eventually pay for the DR of (large) C&I customers who participate in the DRM and receive DR payments. In this sense, those customers who are in a position to offer a DR benefit financially at the expense of all those who cannot.

Implications of the baseline methodology

The consumption baseline approach brings with it significant downside risks and costs. The approach is predicated on the assumption that a customer's (counterfactual) demand in the absence of a DR can be established with some confidence. However, estimating a particular customer's demand over a given timeframe in a reliable manner is an entirely intractable problem that has not been resolved in the US power markets referred to in the Draft Report.

Furthermore, irrespective of the precise way in which the baseline is formulated, the possibility of very high spot price payments creates strong adverse incentives for customers who are in a

position to artificially inflate their load profiles to do so, and to offer demand reductions that have no substance and no value. Adverse incentive effects of this type remain an ongoing and material concern in US power markets that apply a baseline approach.

A common experience in US power markets is that DR mechanisms using a consumption baseline approach encourage customers to move generation 'behind the meter' by using on-site generation, and that customers with on-site generation account for a large share of any load response. Such customers are in a good position to artificially inflate their baseline in order to profit from high spot price payments.

To the extent that the baseline approach encourages significant (opportunistic) investment in on-site generation, it also raises broader questions about its implications for the ongoing viability of existing generators and the longer-term investment efficiency in the NEM. The Small Generation Aggregator Framework currently being developed by the AEMC would seem to avoid these adverse effects by treating such generators more appropriately as generation rather than as DR.

Potential size of DRM demand response in the NEM

The size of any benefits of the proposed DRM will depend on the magnitude of any additional DR it can elicit. The estimates referred to in the Draft Report are likely to significantly overstate the potential demand response from the DRM in the NEM.

The current NEM governance framework already enables customers for whom this is commercially attractive to adjust their demand in response to high prices, including by entering into a supply contract with retailers that incorporate different price risks and opportunities. These arrangements can be designed in a manner that is flexible and mutually beneficial for both sides. Estimates of the size of potentially price responsive demand in the NEM vary, although there is anecdotal evidence from the Australian Energy Regulator (AER) and market participants that significant price responses are observed in the spot market at times of high prices.

The Draft Report refers to comparisons with overseas markets to project that significant untapped DR potential exists in the NEM. Comparisons of DR potential across electricity systems are complicated by market and other local circumstances, but also because of a distinction between 'reliability' DR that is triggered by system conditions versus 'economic' DR (such as the DRM), which is triggered by prices. Reliability and economic DR programs impose different risks and opportunity costs on participating customers.

Given that the proposed DRM is an economic DR program, comparisons with other economic DR schemes (rather than with reliability DR schemes) are relevant for the purpose of determining the potential size of the DRM demand response. The estimates referred to in the Draft Report do not make this distinction and overstate the potential economic DR in the NEM:

- In the United States markets referenced in the Draft Report, reliability DR in the form of contingency reserve and direct load control accounts for the overwhelming share of DR. The reported DR from economic DR programs varies between markets, but generally represents a small fraction of peak demand, far lower than the 6 to 8 per cent quoted in the Draft Report. In four of five US markets considered in this report, the share of peak demand of economic DR lies between 0.5 per cent and 1.6 per cent. The exception is the New England wholesale market, where the share of economic DR is 4.4 per cent.

- FERC's 2010 survey of DR initiatives in the United States suggests that reported potential peak load reductions from C&I customers on economic (pricing) DR programs accounted for 0.5 per cent of peak demand, and that potential peak load reductions from C&I customers on real-time pricing programs accounted for 0.1 per cent of peak demand.

- A 2009 EPRI study referred to in the Draft Report estimates that price responsive DR from C&I customers in the United States would amount to around 0.2 per cent of peak demand in 2010. This share was forecast to rise to 0.7 per cent by 2020.

There are a number of other reasons for adopting a conservative estimate of the demand response potential of the DRM in the NEM:

- The results of voluntary pricing trials that report large demand effects from dynamic electricity pricing cannot generally be assumed to be representative of the underlying population. Such trials disproportionately attract customers who are price responsive, and who therefore stand to gain from participating in the trial.

- The pricing trials that have been done to date provide limited evidence about the extent to which the proposed DRM may encourage additional demand side participation in the NEM:

  - None of the Australian trials of business customers' price responsiveness identified a price effect.

  - US estimates of C&I customers' price responsiveness vary widely. Customers with on-site generation are price responsive, but most other types appear not to be. C&I customers appear instead to shift their consumption to adjacent time periods in response to high prices.

Benefits and costs of the DRM

Some of the benefits from the proposed DRM identified in the Draft Report are questionable:

- Lower prices do not constitute an economic benefit to society, but represent a transfer from producers to consumers. This is a key distinction that is also reflected in the Regulatory Investment Test for Transmission (RIT-T). In any case, and as set out above, the effect of the DRM will not be to reduce wholesale and retail prices. In a dynamic market setting, prices will adjust to account for the changed market risks associated with transfer payments to customers participating in the DRM. As a consequence, retail prices will rise.

- Specifically in the context of an energy-only market like the NEM, a policy designed to suppress prices and reduce infra-marginal rents to generators is not consistent with dynamic efficiency objectives.

Cost savings arising from deferred generation and network investment depend on the level of DR that the DRM could elicit in the NEM, which is likely to be substantially lower than estimated in the Draft Report. In addition, the effectiveness of the DRM in reducing generation and particularly network costs depends on a number of other factors that are not well understood, namely:

- whether identified network investment requirements beyond the current set of price controls are still required, given significant downward revisions in NEM peak demand and consumption trends, and given that peak demand growth appears to have been slowing;
- the extent to which any demand reductions as a result of the DRM might be outweighed by temporal substitution effects that shift consumption and create new demand peaks;
- the predictability and ongoing sustainability of economic DR, which is unknown at this point in time, but is almost certainly lower than that of reliability DR observed in the United States; and
- the extent to which regional demand and pricing peaks coincide with local network peaks, and therefore whether a price response targeted at the system peak will be effective in addressing local network constraints.

Finally, the economic costs of implementing the DRM in the NEM are potentially significant. A large part of these costs will arise irrespective of the level of customer participation in the DRM, since considerable upfront set-up and program development costs would be required. They include:

- the costs of market consultations, the engagement of expert advisors, and ongoing working group and other industry processes;
- the cost of determining and monitoring consumption baselines, including associated significant data processing requirements;
- the cost of installing interval meters and associated infrastructure to participating and non-participating customers (required for the purpose of establishing a statistical control group), as well as any additional costs incurred by customers;
- significant regulatory monitoring and oversight costs related to the use of a consumption baseline approach, as well as the costs of resolving disputes between the scheme administrator and participating customers;
- any changes to existing NEM settlements processes; and
- the costs incurred by load aggregators to establish and run their operations.

1 Introduction

The Australian Energy Market Commission's (AEMC's) Draft Report on the 'Power of Choice' (the Draft Report) recommends establishing a new demand response mechanism (DRM) that would be linked to the National Electricity Market (NEM). The mechanism would enable participating customers to offer a demand response (DR) for which they would be paid at NEM spot prices.

Under the DRM, the level of a customer's DR would be determined with reference to a counterfactual 'baseline', which is intended to capture what the customer's consumption pattern would have been in the absence of the DR. The baseline would form the basis for settling retailers' spot market purchases on behalf of participating customers, and for determining these customers' liabilities to their retailers. In the event that a DR occurs, actual (metered) load would be less than the baseline over the DR timeframe. Retailers' payments for (baseline) spot market purchases to the Australian Energy Market Operator (AEMO) would then exceed the cost of actual spot market purchases, since actual spot market volumes would incorporate the DR. AEMO would pass the resulting surplus through to participating customers or to third parties acting on their behalf.

1.1 Terms of reference

We have been asked by the Energy Supply Association of Australia and the National Generators Forum to prepare an assessment of the economic implications of the proposed DRM. The purpose of this report is to assess any implications for economic efficiency and other economic effects that may potentially arise as a result of the proposal, including:

- the impacts and risk exposure on market participants, and effects on hedging strategies;
- the risks and incentives associated with the baseline consumption concept;
- whether international comparisons of potential uptake are valid;
- the range of costs that would be incurred; and
- the implications for longer-term investment and security of supply.

1.2 About this report

This report is structured as follows:

- Section 2 considers the implications of the DRM for NEM participants and for consumers, and discusses the incentive properties of the baseline approach;
- Section 3 comments on the potential magnitude of the demand response from the DRM; and
- Section 4 discusses the potential benefits and costs of the DRM.

2 Implications for NEM participants, consumers and customer incentives

The proposed DRM would link payments to customers for reducing their demand to NEM spot market outcomes. The level of any DR, and therefore the quantum of payments to participating customers would depend on the customers' consumption baselines. This section considers the economic implications of this mechanism:

- by tracing through the consequences of the proposed DRM on the operations of NEM spot and contract markets, the effects on wholesale and retail prices, and the eventual impacts on consumers; and
- by analysing the incentive effects that the baseline mechanism creates for participating customers.

2.1 Market and price effects of the DRM

This section describes the current operation of NEM spot and contract markets and the economic effects of the DRM. The DRM introduces a disconnect between retailers' hedging requirements, as reflected in the baselines of DR customers, and actual generation in the spot market. In the short run, generators will therefore be exposed to greater financial risks from unfunded difference payments. However, financial (contract) markets adjust very quickly to changed risks, so that the prices of hedge contracts required by retailers will increase. These costs will be passed on to consumers. The overall economic effect of the DRM is then that markets and prices adjust to a new equilibrium in which the cost of (potentially very) high payments to participating customers are transferred to consumers as a whole.

2.1.1 Mechanics of NEM trading arrangements and the DRM

As things currently stand, most consumers in the NEM are supplied on fixed tariff contracts by a retailer who procures electricity on their behalf. Retailers estimate consumers' expected consumption patterns over time using demand profiles akin to a baseline. Consumers may use more or less electricity than the baseline, but these deviations can be viewed as random overall. Consumers pay the same tariff for deviations above or below any notional baseline.

Retailers hedge the volume and spot price risks associated with their customers with generator counterparties in the contract market. Generators in turn estimate their likely dispatch and hedge their output up to or below that level of dispatch. Retailers and generators face offsetting although not symmetric price risks; the distribution of these risks will be reflected in the price of the contracts for differences (CFDs) or similar risk management instruments that they enter into. In short, the prices and terms of CFDs adjust to share wholesale market risks between the parties in an optimal fashion.

Under the DRM, a customer pays the contract tariff for consumption in excess of the baseline, and receives the spot market price for consumption below the baseline. Irrespective of the level of the customer's consumption, retailers will effectively be required to hedge the customer's load as per the customer's baseline since that load will be settled according to the baseline. If a customer elects to offer a DR, however, the customer's actual consumption over some timeframe will be less than the (hedged) baseline, so that actual generation will also be less than the baseline. As a consequence, one or more NEM generators will be effectively 'overhedged' and liable for 'unfunded difference payments' on their contracts. In other words, generators will be required to make cash difference payments on contracts that are not funded by revenues in the spot market. If spot prices are high, these payments can be very substantial.

2.1.2 A static example

Figure 1 below illustrates the implications of the DRM for a simplified numerical example with a customer, a retailer, and a generator. The customer has a baseline of 10MW and reduces demand over an hour by 2MW. The customer's actual (metered) load is therefore 8MW. The retail price charged to the customer is $50/MWh. Two alternative market outcomes are considered:

- Case a): the retailer hedges the customer's *baseline* load of 10 MW by entering into a CFD with the generator for 10 MW at a strike price of $50/MWh; and

- Case b): the retailer hedges the customer's *actual* load of 8MW on the same terms.

In Case a), the generator is liable to unfunded difference payments to the retailer corresponding to 2MW multiplied by the prevailing spot price minus the contract strike price. These payments arise because the generator only generates 8MW (and is paid for 8MW at the spot price), but is obliged (under the CFD) to reimburse the retailer for 10MW multiplied with the spot price minus the contract strike price. The level of unfunded difference payments rises in proportion to the spot price.

For example, at a spot price of $1,000/MWh, the economic effects of the DRM can be understood as follows:

- The generator is paid $8,000 = (8MW x $1,000/MWh) in the spot market, but must pay the retailer a CFD difference payment of (-)$9,500 = (10MW x ($1,000/MWh - $50/MWh)), corresponding to a financial loss of (-)$1,500. In the counterfactual (no DRM), the CFD would match the customer's actual metered consumption of 8 MW. The generator is paid $8,000 in the spot market, but must pay the retailer a CFD difference payment of (-) $7,600 = (8MW x ($1,000/MWh - $50/MWh)) and would earn $400. Relative to the counterfactual without the DRM, the generator is worse off overall by (-)$1,900.

- The customer pays the retailer $500 for their baseline consumption (10MW x $50/MWh), and receives $400 worth of electricity, given that there is a DR (8MW x $50/MWh). The customer also receives a payment of $2,000 for the DR (2MW x $1,000). Overall, the customer is better off by $1,900.[1]

- The retailer is left financially neutral. The retailer pays $10,000 corresponding to baseline consumption of 10MW to AEMO, receives a difference payment from the generator of $9,500, and is paid $500 by the customer for baseline consumption of 10MW.

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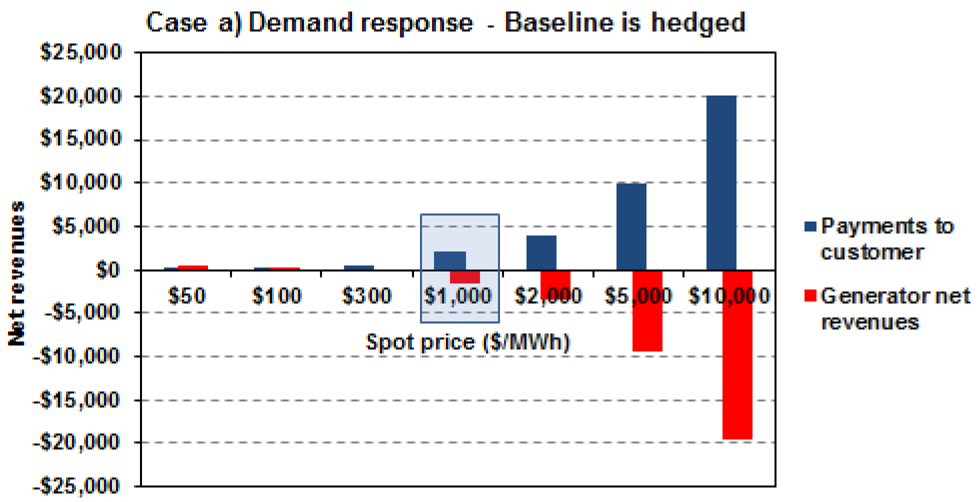
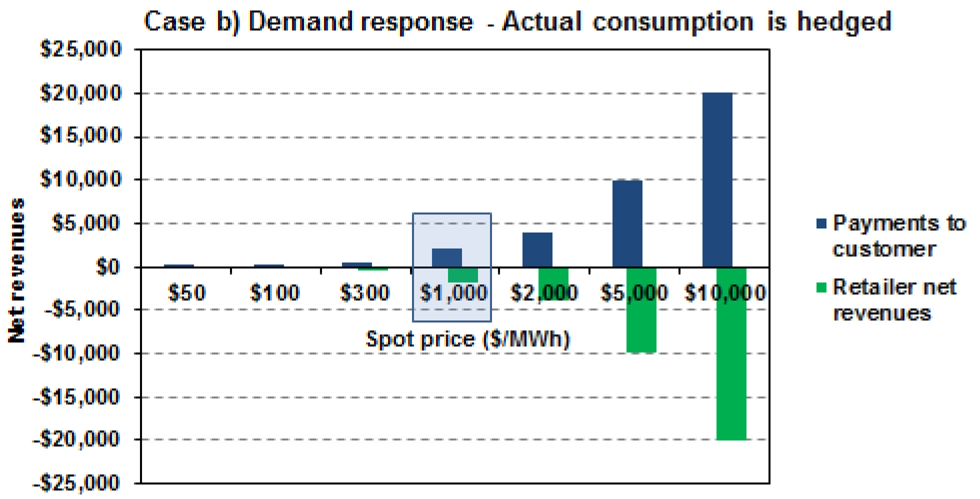
[1] In a cost-benefit type calculation such as the one above, all benefits and costs need to be included. For example, if the customer makes a payment and receives electricity in return, the value of the electricity must also be accounted for in the calculation. For the purposes of this example, it is assumed that the customer's marginal value of consumption equals the retail price at any one time.

Figure 1. Transfer payments and net participant revenues under the DRM





Notes: In the above examples, baseline MW = 10, metered MW = 8, demand response MW = 2, the contract strike price = $50/MWh. In case a), contract volume = 10. In case b), contract volume = 8.

In Case b) the retailer only hedges the customer's *actual* consumption of 8MW. This would be the likely outcome if the generator becomes aware that demand in the spot market is consistently less than its contract commitment (thus giving rise to unfunded difference payments), and limits the number of hedges it sells. The retailer is still required to pay AEMO for the customer's baseline demand of 10MW but is only hedged to 8MW, and is therefore exposed to spot market price risks for 2MW. The higher the spot market price, the greater are the losses incurred by the retailer. At a spot market price of $1,000, the retailer makes a net loss of (-) 1,900.[2] The overall gain for the customer is unchanged at $1,900: the customer pays the retailer $500 for baseline consumption, receives electricity worth $400, and receives a payment of $2,000 for the DR. The generator is left financially neutral.

[2] The retailer must pay 10MW x $1,000 = $10,000 for its spot market purchases, receives CFD payments from the generator of $7,600 = 8MW x ($1,000/MWh - $50/MWh), and receives retail payments from the customer of $500 = 10MW x $50/MWh.

The two cases illustrated in Figure 1 represent two opposite ends of the spectrum, in which the customer's DR is either fully hedged or not. It is possible to construct many intermediate cases in which some share of the customer's DR is hedged, but the implications are always the same: any payments made to participating customers are direct transfers, either from the generator or from the retailer, or from a combination of both. How the financial losses are allocated depends only on the degree to which the customer's baseline is hedged in the contract market.

2.1.3 Dynamic effects

The financial losses illustrated in the above example arise purely because of the mismatch between contract market transactions and actual demand as it appears in the spot market, and not because of the customer's demand reduction. These losses instead reflect the fact that under the DRM, the customer receives a free option that is potentially very valuable because it entails no downside risks (since the customer pays no more than the retail price) and considerable upside risk (since the customer has the option of reducing consumption to earn NEM revenues). An outcome in which NEM participants consistently incur financial losses in the course of their trading operations because of an underlying mismatch in risks is not sustainable, and prices in the contract and retail market will adjust to unwind it.

This effect can be illustrated by continuing with the above example (summarised in Annex A). In Case a), the spot price is $1,000/MWh, the customer gains $1,900 and the generator loses (-) $1,900. This is not a stable equilibrium, since one party in the trading relationship (the generator) consistently loses. The distribution of risks in the contract market has changed (to the detriment of the generator), and the price of CFDs will therefore adjust until the generator is no worse off than without the DRM. That new equilibrium price of CFDs is $190/MW (which equals the expected loss of (-)$1,900 incurred by the generator from selling 10MW of CFDs). At that contract price:

- The generator receives $1,900 = (10 x $190) for selling CFDs to the retailer, receives spot market revenues of $8,000 = (8MW x $1,000/MWh), and must make a difference payment of (-)$9,500 = (10 x ($1,000 /MWh - $50/MWh)) to the retailer. The generator earns $400, and is no worse off than without the DRM.

- The retailer pays (-)$1,900 for the CFDs, must make spot market payments of (-) $10,000 = (10MW x $1,000/MWh), receives difference payments from the generator of $9,500, and receives $500 = (10 x $50/MWh) from the customer. At a tariff of $50/MWh, the retailer therefore makes a loss of (-)$1,900. The retail price will therefore need to adjust from $50/MWh to $240/MWh to reflect the cost of the CFDs ($190/MWh). At that tariff, the retailer will again earn zero on net and will be no worse off than without the DRM.

- The customer now receives $2,000, corresponding to the DR payments (2MW x $1,000), receives 8MW of electricity valued at $400, and pays the retailer (-)$2,400 = (10MW x $240/MWh). At that tariff, the windfall gain to the customer is eliminated, and the net profit to the customer is again zero.

Overall, all parties are as well off as they were before the DRM caused the transfer payment to be made to the customer. In economic terms, the net benefit of the DR to society is *only* the difference between the avoided cost of generating 2MW of electricity output, and the opportunity cost to the customer of reducing their consumption. If, say, the avoided short run marginal cost of generation is $100/MWh and the cost to the customer of making up production lost as a result of the DR at another time is $180, the net economic benefit of the DR is $20.

2.1.4 Overall economic implications of the DRM

The above example is highly stylised but captures the basic economic incentives of the key players. It assumes a highly simplified market structure, that wholesale prices will not change as a result of the DR, and only considers a single (one hour) demand interval. The conclusions nonetheless illustrate a key point: the disconnect between the economic value of the DRM and the incentive payment to the customer is the reason why this scheme is ultimately self-defeating. The generation cost saving is the only 'real' benefit from the DRM; any short-term financial transfers that do not reflect the economic value of the DR cannot be sustained.

The same effects would also be expected to occur in real life. Financial markets for risk management products adjust very quickly to changes in the distribution of risk. In any realistic and sustainable scenario, a scheme that transfers risks from producers to consumers without some form of compensation will be unwound, as prices for risk management products adjust to a new equilibrium. Higher prices for risk management products will be initially be borne by retailers; sooner or later they will be passed through to consumers in the form of higher retail prices.

The DRM scheme also has two further consequences that merit consideration:

- First, the DRM transfers the financial cost of paying for the DR by a limited number of customers to consumers as a whole. If retail prices increase across the board, including to small consumers, all consumers will eventually pay for the DR of those (large C&I) customers who participate in the DRM. In this sense, the DRM raises an equity issue: those customers who are able to offer a DR benefit financially at the expense of all those who cannot.

- Second, the DRM exacerbates the pricing inefficiency associated with averaged retail tariffs during low price periods. As is illustrated in Section 4.1, averaged retail prices imply a pricing or 'allocative' inefficiency, which gives rise to a 'deadweight loss'. That deadweight loss arises because during off-peak periods, when electricity spot prices are low, consumers use 'too little' electricity, while consumers use 'too much' electricity during peak hours when prices are high. However, the ultimate effect of the DRM is to increase retail prices (since retailers will pass the increased cost of managing wholesale market risks on to consumers). If retail prices are higher in all periods, including during off-peak periods, the deadweight loss increases for those off-peak periods.

2.2 Baseline incentive effects

The operation of the DRM relies on the existence of a baseline that is intended to measure a customer's consumption in the counterfactual. The application of a baseline to estimate customers' demand responses has been used in some US power markets for some time and remains a problematic and unresolved issue. Two factors account for this:

- the difficulty of estimating any particular customer's 'normal' electricity demand at any point in time; and

- the inherent adverse incentive problems that a mechanism such as the consumption baseline creates.

2.2.1 Estimating a customer's baseline electricity consumption

The consumption baseline mechanism fundamentally relies on the ability of an outside party to predict a particular customer's level of normal electricity consumption at any given point in time. However, even the best economic or statistical models of a customer's hourly electricity consumption as a function of prices and *observable* customer and weather characteristics are only able to explain a small fraction of the variation in that customer's electricity consumption across hours of the year (Bushnell et al. 2009). The factors that account for the variability of customers' load shapes observed in practice include:

- variations arising from different patterns of activity by time-of-day, day-of-week and day-of-month, seasonal patterns and month-of-year effects, all of which are overlaid with other random changes in activity that defy a regular pattern;

- variability arising from weather-dependency, which is further complicated by inter-temporal effects (since the load shapes of three hot days in a row are different from the load shapes of three isolated hot load days), and which will differ depending on the characteristics of the customer (for instance, whether or not the customer has one or more air conditioners); and

- variability arising from the heterogeneity of customers who differ (for residential customers) by income, type and size of dwelling, number and types of appliances etc., and (for businesses) by size, level and type of commercial or industrial activity, type and size of building, machinery and equipment used, including heating and cooling equipment, etc.

2.2.2 Adverse incentive effects

Much of the information that determines a customer's electricity consumption is 'private', in the sense that it will only be known to the customer. Customers will know when their consumption will be high or low for any reason, including because of holidays, higher or lower demand for their products, changes in the production cycle, or other factors. This gives rise to what has come to be known as 'the baseline problem' (Bushnell et al. 2009, Chao 2010). The baseline problem refers to two difficulties that are generally found in circumstances where one party to a transaction (in this case, the customer) has private information that the other lacks (the DR scheme administrator), namely an adverse selection problem and a moral hazard problem.

The adverse selection problem arises from the fact that the 'buyer' of DR does not know what the customer would have consumed in the counterfactual. Customers have better information about their baseline consumption than the DR scheme administrator and will use that information in deciding whether or not to participate in the DR program. DR programs referenced to a baseline therefore disproportionately attract customers who anticipate lower consumption for reasons that are unrelated to a valid demand reduction. For instance, if a previous year's consumption is used to determine the baseline, firms whose production has fallen since the previous year are likely to sign up. These firms will be paid for demand reductions that would have occurred anyway. Firms whose production and electricity consumption have grown since the previous year will not sign up (Bushnell 2009).

The moral hazard problem arises because DR payments to customers directly increase with the baseline. There is therefore a strong incentive for customers to inflate their baselines in order to profit from high spot market payments. The most obvious example where this effect can occur is in circumstances where a customer uses on-site generation, which can be turned off temporarily to establish an artificially high baseline level of consumption. This is only one of many types of behaviours that have been observed in practice. The CAISO Market Surveillance Committee of the California wholesale market, for instance, comments in some detail on 'phantom demand response' observed, including the widespread practice of customers purchasing small generators and moving generation 'behind the meter' (CAISO 2011).

The baseline problem is inherently intractable and cannot be 'fixed' by adopting different or more sophisticated approaches to calculating a customer's baseline (Ruff 2002). A recent study undertaken by KEMA (2011) for PJM's Load Management Task Force, for instance, examined:

- customer and customer load information from 4,565 DR customers and 16,000 non-DR customers as a control group;
- hourly load data from June 1, 2008 through September 30, 2010;
- 11 baselines, with up to four variants of each baseline for a total of 36 different baselines and adjustment methods;
- resulting in nearly 150 million estimated customer baselines.

The analysis was intended to determine the accuracy and bias of different baseline methods, assess the feasibility of administering each method, and determine whether objective criteria to associate a customer load with a specific baseline method could be developed. KEMA proposed a number of sophisticated adjustments to improve PJM's existing technology, but concluded that:

- no generalised methodology can produce an effective baseline to measure demand reductions from customers with high (non-weather related) variability; and that
- more generally, any baseline can be manipulated to the customer's economic advantage, particularly in circumstances where customers have advance knowledge of a likely DR event and where the customers can decide the timing of the 'DR'.

2.2.3 Experience in the United States

Federal Energy Regulatory Commission

The inherent difficulties and controversies of the baseline approach have been described by the Federal Energy Regulatory Commission (FERC) in its reports to Congress over the years, including in 2006 (FERC 2006, revised 2008) and in FERC's 2010 assessment of demand side participation (DSP) in the United States FERC (2011a). As of late 2011, FERC (2011b) stated that problems associated with the measurement of demand reductions remained. While two exhaustive analyses of methods to estimate customer baselines had been prepared for PJM and for the New England electricity wholesale market, additional work was still needed.

The PJM experience

PJM's Economic Load Response Program (ELRP) has a similar in-principle design as the DRM. ELRP participants receive credits for load reductions priced at the spot price, and the DR is settled relative to the customer baseline. PJM's Market Monitoring Unit (MMU) has been tasked with overseeing the operation of the program, including that of the baseline. As summarised by the MMU in its 2011 State of the Market Report (Monitoring Analytics, MA 2012b, P.139):

> *Since the beginning of the program, there have been significant issues with the approach to measuring demand-side response MW.*

The MMU's State of the Market reports provide an indication of the practicalities of attempting to monitor customers' demand responses on the basis of a counterfactual baseline. From the beginning of the economic DR program there were multiple settlement disputes with customers and/or load aggregators requiring the involvement of the market operator (MA 2009). A detailed analysis by the MMU of 2008 historical settlement data concluded that at least 40 per cent of payments made for claimed demand responses were based on inflated baselines. PJM then obtained regulatory approval to change its baseline calculations and initiated various approaches for screening out unjustified DR payments. In 2011, PJM commissioned the in-depth baseline analysis described above (KEMA 2011).

As of the beginning of 2012, the difficulties identified in earlier assessments of the baseline approach have not been resolved (MA 2012b). The MMU continues to identify numerous instances of customers requesting payments for DR in circumstances where there is strong evidence to suspect an inflated baseline. Similar issues have been encountered in other wholesale markets (CAISO 2011).

2.3 Conclusions

The proposed DRM would offer customers a riskless and valuable option, which they could exercise to earn potentially very high spot market revenues. This mechanism offers very large transfer payments to customers providing a DR that do not reflect its economic benefit from the DR. The resulting changed risk distribution in the wholesale market will result in adjustments in the prices of financial risk management products, and ultimately in adjustments in retail prices. In this way, transfers from producers to DR customers will be unwound; the cost of payments to large C&I customers under the DRM will ultimately be borne by consumers in the form of higher retail prices.

Increased retail prices furthermore lead to two other consequences:

- the cost of paying for the DR response from a limited number of large C&I customers is transferred to consumers as a whole, so that those customers who cannot participate in the DRM effectively subsidise those who do; and

- if retail prices rise across the board, including during off-peak periods, the pricing inefficiency associated with averaged retail prices increases in those periods.

The consumption baseline approach is predicated on the assumption that a customer's (counterfactual) demand in the absence of a DR can be established in a reliable manner. However, irrespective of the precise way in which the baseline is formulated, the possibility of receiving very high spot price payments creates strong incentives for customers who are in a position to manipulate their load profiles to do so, and to offer demand reductions that have no substance and no value.

3 Potential size of DRM demand response in the NEM

This section considers the quantum of the DR that the DRM might elicit in the NEM by considering, in turn:

- customers' incentives to provide different types of DR;
- current estimates of the size of price responsive DR in the NEM;
- the relative magnitude of DR that similar mechanisms to the DRM have achieved in overseas markets; and
- the lessons that can be drawn from Australian and US surveys of customers' demand responsiveness.

As set out in the following, there are a number of reasons for thinking that estimates presented in the Draft Report of the potential uptake of the DRM are likely to be overstated, and that hence any benefits from the DRM would also be reduced.

3.1 Customers' incentives to provide demand response

In the most general sense, DR refers to actions that can be taken by electricity customers to reduce load in response to certain market or system conditions. DR programs differ across multiple dimensions, but can be broadly classified according to the type of 'event' that triggers a load response, and according to which party takes the decision to deploy the DR (NERC 2012):

- 'reliability' DR primarily provides system security or reliability benefits, and is called by the system operator under certain system conditions; and
- 'economic' DR primarily represents a price response that is initiated on a voluntary basis by the customer.

The proposed DRM would therefore be classed as an economic DR program.

In many instances, the impacts of reliability DR and economic DR overlap; for instance, economic DR may reduce peak demand and improve system security and/or provide longer term system benefits. The distinction is important, however, because the economic incentives for customers to participate in different types of DR programs differ. This complicates international comparisons of the level of DR that can be expected.

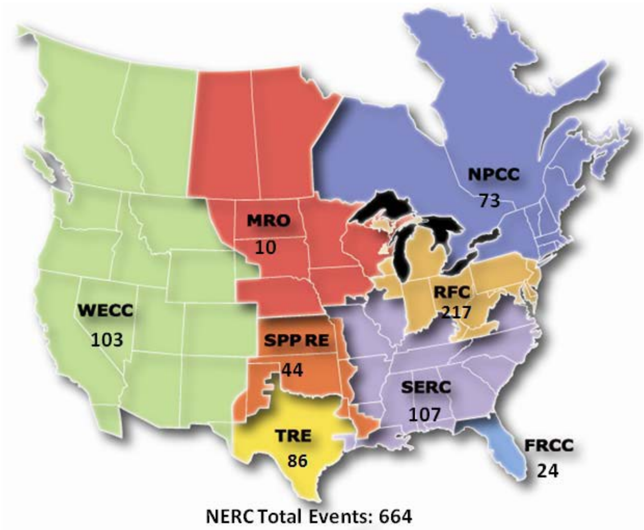
3.1.1 Reliability DR programs

DR has traditionally been applied as one of a number of services that are required in all power systems to maintain the ongoing security and reliability of operations. In that (reliability) role, DR can provide reserve services, capacity services such as interruptible load and direct load control (DLC), as well as other ancillary services.[3] In US markets, which are referenced in the Draft Report and by enerNOC (2012), reliability DR programs play a far more important role in

[3] DLC programs, which centrally control customers' water heating, lighting, pool pumps or air conditioning, differ somewhat from other reliability DR programs in that they tend to be targeted at small customers.

maintaining system reliability than is the case in the NEM. Figure 2, for instance, provides an indication of the number of load shedding events during the (hot) 2011 summer in the United States. Most US power markets operate multiple reliability DR programs in which customers can participate (often in separate capacity markets), and which impose different obligations on the customer. In contrast, AEMO does not contract with customers to provide contingency reserve services in the normal course of events.

Figure 2. 2011 Summer – Number of contingency and emergency DR events (North America)



Source: NERC 2012.

All types of DR impose direct and opportunity costs on the relevant customer. In terms of direct costs, loads who provide reliability DR services must generally meet stringent equipment and testing requirements in order to be considered a reliable 'resource' from the system operator's perspective (Kirby 2006). Loads must be capable of being curtailed rapidly and accurately, must be able to communicate with the system operator, and must be capable of being monitored. Furthermore, and while the initial decision to participate in a reliability DR program is voluntary, compliance with system operator instructions is usually mandatory.

At least in the United States, where reliability DR programs are common, providing reliability DR (such as contingency reserve) is generally a more attractive economic proposition for customers than providing economic DR (FERC 2006, EPRI 2008a). This reflects both the structure of payments to customers and the opportunity costs of providing reliability DR. Customers that provide reliability DR typically receive a recurring guaranteed payment for a service that requires the load to be ready to respond within some agreed timeframe if directed to by the system operator. In mild weather and system conditions, the reliability DR response may never be called. In these circumstances, providing reliability DR imposes technical communications and control costs on the customer, but may not otherwise interfere with normal business activities at all. In addition, and in the relatively infrequent event that a load is dispatched to provide a reliability DR, duration of the load response is typically relatively short (Kirby 2006).

3.1.2 Economic DR programs

Economic DR is triggered by the price or tariff paid by the customer, and the decision to offer a DR is entirely voluntary.[4] Unlike a customer providing reliability DR, however, a customer who provides economic DR in response to high prices must definitely curtail their consumption, which entails a (potentially very significant) opportunity cost. Customers contemplating an economic DR therefore face a trade-off, in terms of any bill savings they can achieve versus the direct and opportunity cost associated with curtailing their consumption.

Direct and opportunity costs of an economic DR

Reliability DR programs require customers to follow (typically relatively infrequent) instructions from system operators. In contrast, economic DR programs require a greater degree of engagement on the part of the customer. Time-of-use (TOU) pricing requires the customer to be aware of different peak and off-peak tariffs and the times over which these apply. Customers on critical peak pricing (CPP) tariffs generally receive some advance warning of an impending 'event' and may elect to curtail their consumption during the event. Real-time pricing (RTP) schemes imply that customers dedicate the resources to monitor spot market prices (or contract with an aggregator to do so on their behalf), either on an ongoing basis or at least in circumstances when prices are likely to be high.

Economic DR programs involving time-variant pricing approaches such as CPP and RTP schemes are settled on an hourly or less basis. Customers participating in these types of schemes therefore require (interval) metering and recording equipment to be installed at their premises, and communications systems to be in place between the customer and whichever party undertakes the monitoring and settlement function. Customers may also need to make certain other upfront investments that enable them to manage their energy consumption, for instance in energy management systems that centrally monitor, analyse and control building systems and equipment.

A more material cost to customers, however, is likely to be the opportunity cost of curtailing consumption. For C&I customers, these opportunity costs relate to foregone production or sales and in some cases damage to equipment and/or other longer term costs. These opportunity costs from lost production and sales will vary widely by industry sector, and depend on the complexity of a customer's operations, but can potentially be very large. For instance, commercial customers may rely on sophisticated IT equipment for their larger operations that cannot be shut down, or may be concerned about changes in cooling, heating or lighting affecting the comfort of building occupants. Industrial customers may have to interrupt individual processes with associated knock-on effects for aggregate production that cannot be made up later. It is for these reasons that estimates of the value of lost load (VOLL) for C&I customers tend to be significantly higher than is the case for residential customers. The most recent VOLL estimates prepared by AEMO for Victoria assume an average cost of supply interruptions for residential customers of $16.33/kWh versus $45.94/kWh for industrial customers and $134.15/kWh for commercial customers (AEMO 2011).

One class of (large) customers who are generally in a good position to offer economic DR services are those with on-site generation (for instance, back-up generation). In the United

[4] Irrespective of prices and tariff structures, customers may, of course, respond to higher electricity prices and bills by reducing their overall and peak consumption. As set out by AEMO, customers' responsiveness to rising electricity prices is one of the key factors that accounts for the significantly reduced annual energy and maximum demand projections for the NEM relative to past forecasts (Section 4.2).

States at least, the experience has been that large customers with on-site generation often account for a significant part of the observed price response. However, as discussed in Section 4.1, the DR of these types of customers raise a number of other issues.

Economic DR and the business cycle

The opportunity costs to customers of curtailing their electricity consumption are unlikely to be fixed over time. In the current business climate, for instance, many manufacturing businesses may be operating at the margins of profitability and may be happy to close down their operations for a day or two and send their employees home. They would be far less likely to do so in buoyant economic conditions where production must be maintained, and where there are real opportunity costs from failing to meet production targets.

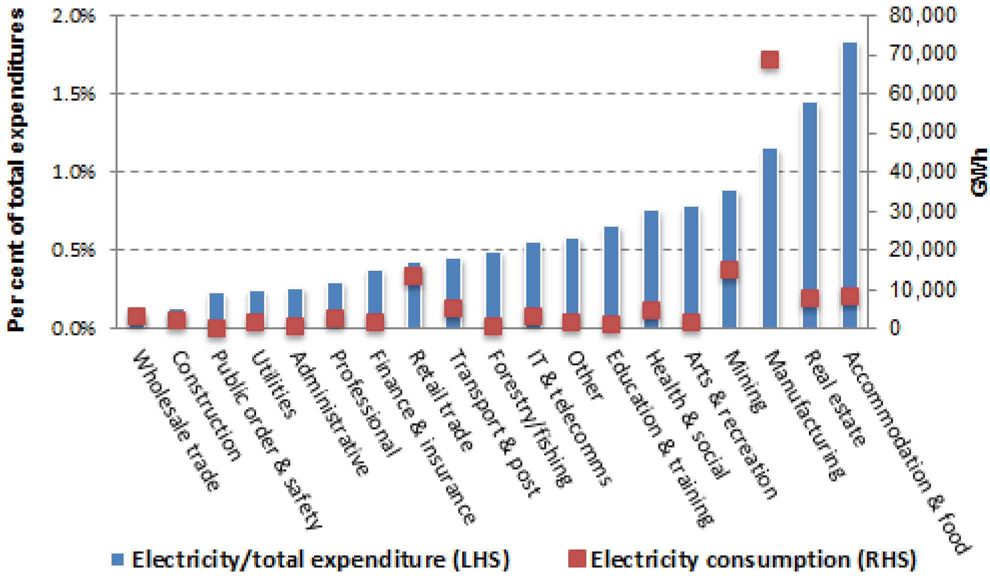
Potential bill savings

From the customer's perspective, any potential opportunity cost from reducing consumption must be weighed up against the potential bill savings from the DR. In the case of reliability DR, payments that customers receive are agreed in advance and assured (provided that the customer meets ongoing testing requirements and complies with system operator instructions). In the case of economic DR, this is not the case. The DRM, for instance, would reference payments to highly variable wholesale market prices, and the timing of any response will therefore matter. Unless a customer can respond to high prices within a relatively short timeframe, there is limited certainty about what price they will be paid. Hence, if the opportunity costs of reducing consumption are substantive, customers might not be willing to take the risk.

There is also a more general question about the number of customers who can respond to high prices within a very short timeframe. For most customers, the shorter the advance notice of a potential price opportunity, the less likely it is that they will be able to curtail their consumption. In the very short-term, for instance, supply commitments will have been entered into, staff are on hand and have to be paid, or customers are waiting. This proposition is also borne out in surveys; for instance EPRI (2008b) reports that customers are more price responsive when they receive longer notice (a day ahead rather than one hour ahead) of an impending price change.

Some large customers will have either the operational flexibility or, more likely, the on-site generation, to enable them to significantly reduce their demand in response to high prices. However, it is also important to recognise that for the majority of C&I customers, expenditures on electricity are a very small share of their total costs (Figure 3). Figure 3 contrasts expenditure shares on electricity (which include both energy and network costs) with aggregate electricity consumption. For all but three industry divisions, average expenditure on electricity is less than 1 per cent of total business expenditures. The percentage share of expenditures on electricity are highest for the real estate and accommodation & food services sectors, but these sectors only account for a small proportion of aggregate consumption. For many commercial businesses, an uncertain reduction in their electricity bills, which represent only a very small share of their overall expenditures, may not warrant the direct and opportunity cost of curtailing their consumption.

Figure 3. Percentage expenditure on electricity, by industry division (2008-09)



Source: Australian Bureau of Statistics 2010. 4660oDO004_200809 Energy, Water and Environment Management, 2008-09, Table 5. 11 November.

3.2 Estimates of potential economic DR in the NEM

This section reviews the available information on the current level of economic DR in the NEM and estimates in the Draft Report of the potential DRM demand response. These estimates are based on comparisons between power systems and markets which differ in important respects from the NEM, and which do not draw a clear distinction between reliability and economic DR.

3.2.1 Current estimates of DR in the NEM

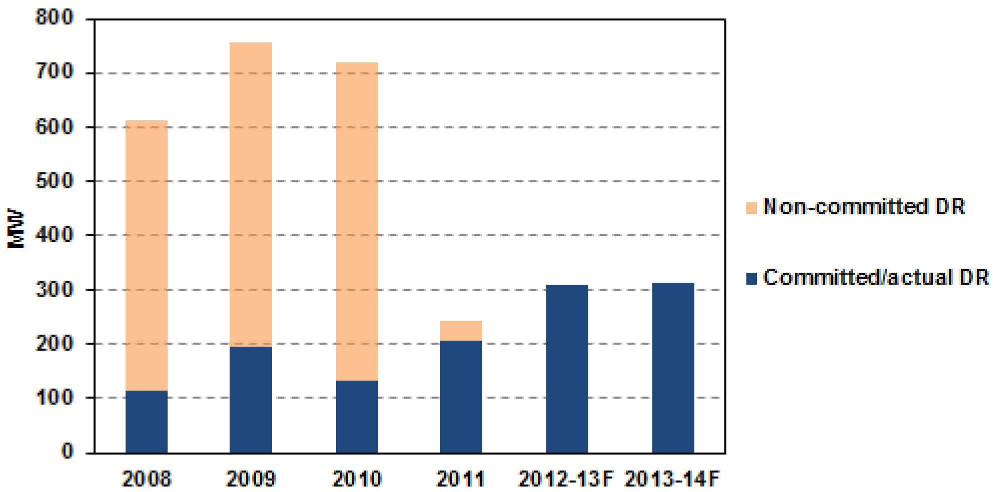
The current NEM governance framework already enables customers for whom this is commercially attractive to adjust their demand in response to high prices. Very large customers can register with AEMO and purchase their power requirements directly in the spot and contract markets. More generally, C&I customers are able to enter into supply contract with retailers that incorporate different price risks and opportunities. These arrangements can be designed in a manner that flexibly addresses the circumstances of a particular customer and is mutually beneficial for both sides. In either case, these customers provide an economic DR by modifying their consumption according to spot market price outcomes. At least one load aggregator is also active in the NEM.

The size of economic DR in the NEM is opaque. AEMO regularly reports on the level of aggregate DSP in the NEM on the basis of annual surveys of NSPs, retailers, load aggregators and other market customers to determine the 'maximum potential' DR in the NEM (Figure 4).[5] AEMO's estimates do not distinguish between reliability and economic DR, and include all

[5] In addition, AEMO separately publishes estimates of price responsive demand for the purpose of preparing the National Transmission Development Plan (NTDP). These estimates (prepared for planning purposes) are conservative and assume an economic DR in the range of 94 MW for prices above $1,000/MWh - $3,000/MWh, and of 126MW for prices above $5,000/MWh.

short-term demand reductions in response to high prices or other price incentives from verifiable demand management schemes (but excluding demand shifting from DLC), and under Network Support and Control Services (NSCS) agreements. In addition, AEMO undertakes a counterfactual simulation of historical NEM outcomes to derive an estimate of 'committed' or 'actual' DR. Figure 4 suggests that AEMO expects to see around 300MW of price responsive demand in the spot market over the next two years.

Figure 4. Demand side participation in the NEM



Notes: The sum of committed and non-committed DSP equals maximum potential.

Source: ESOO 2009, 2010, 2011, NEFR 2012.

There is other (anecdotal) evidence of economic DR in the NEM. In its 2011 State of the Market report, the Australian Energy Regulator refers to a number of instances of DSP in the NEM, including a demand side reduction of 150MW in Tasmania on 25 July 2011, and a 300MW demand response in New South Wales on 10 August 2010. At least in part, significant discrepancies between forecast and actual electricity consumption and peak demand (Section 4.2), are also an indication that customers are price responsive. As the cost of smart meters/ AMIs continue to decline, smaller customers may increasingly find it profitable to enter into contracts with retailers that reward price responsiveness.

Unlike electricity generation, where the output can be measured, estimates of price responsive demand are just that. Deriving an estimate of the price response of demand in the NEM requires an understanding of what demand would have been in the absence of high prices (akin to estimating a baseline). In most cases, only the customers themselves will know what their counterfactual demand would have been.

AEMO (or any other party's) ability to estimate the level of DR in the NEM is correspondingly limited by the fact that AEMO must rely on information and estimates provided to it by third parties, and by AEMO's ability to reconstruct past events that have taken place over very short-term trading intervals in the spot market. This may account for the fact that market participants report significantly higher estimates of price responsive demand in the NEM than AEMO of around 1,500MW. These higher estimates are based on observed loads shifts in response to high prices in the course of market participants' trading operations.

3.2.2 Draft Report estimates of potential DR in the NEM

The Draft Report (Appendix A.5) states that the DRM is expected to potentially capture 2,100 to 2,800 MW of DR from C&I customers. However, many of the estimates that are cited rely on comparisons of overseas markets with the NEM. As a general matter, comparisons between electricity markets and power systems are problematic because of different institutional and governance arrangements, differences in size, and in the structure of the supply and the demand side. As stated by the North American Electric Reliability Corporation (NERC) in the context of comparisons of reliability DR performance metrics between NERC reliability regions (NERC, P.98):

> *[demand response] metrics should not be compared between regions or subregions as their bulk power system characteristics and market structures differ significantly in terms of resource-mix, system and market design, load characteristics, and simple physical, geographic, regulatory, and climatic conditions.*

In the case of comparisons between the NEM and US power systems, these differences also relate to long standing operational practices, in terms of the degree of reliance (in the United States) on interruptible loads to manage contingencies and the role that loads play in capacity markets. Many US wholesale markets incorporate a 'capacity obligation' whereby retailers must show that they have sufficient capacity to meet the demand of their customers (including capacity in the form of reliability DR); many also have day-ahead capacity markets in which loads can commit to reducing demand in real-time in the event of a contingency.

The studies cited in the Draft Report do not appear to consider these limitations. More importantly, as set out in the following, and for the US estimates, the reported percentage estimates of DR refer to the sum total of all demand responses, including reliability DR (curtailable and interruptible load, as well as DLC) and economic DR. These figures therefore (significantly) overestimate the amount of economic, i.e. price-responsive DR in the United States. It is therefore fair to conclude that extrapolating these estimates to the NEM would overstate the potential for economic DR.

Oakley Greenwood/enerNOC

The Draft Report refers to Oakley Greenwood analysis which derives the 2,100 – 2,800MW estimate by assuming that 6 to 8 per cent of NEM peak demand of 35,000 MW could be reduced by the DRM. The 6 to 8 per cent estimate appears, in turn, to be derived from an enerNOC presentation. That presentation states that "Other markets have shown that 10% penetration is achievable" (enerNOC 2012), and appears to generally refer to US power markets. However, these estimate substantially overestimate economic DR outcomes in the United States.

FERC's most recent (2010) detailed survey of DR initiatives indicates that the total reported *potential* peak load reduction from reliability and economic DR was around 53,100MW or 7 per cent of peak demand (FERC 2011a). The total reported *actual* DR in 2010 was around 16,000 MW (including reliability and economic DR), corresponding to around 2.1 per cent of peak demand. The potential load reductions from DR cited by FERC overwhelmingly refer to those from reliability DR programs (such as emergency demand response, interruptible load and DLC). Reported potential peak load reductions for C&I customers on economic (pricing) DR programs accounted for 0.5 per cent of peak demand, and reported potential peak load reductions from C&I customers on RTP programs accounted for 0.1 per cent of peak demand.

Table 1 below shows recent estimates of reliability and economic DR for selected US power markets. With the exception of the New England electricity market (ISO NE), economic DR is generally only a very small fraction of peak demand, and far less than the 6 to 8 per cent assumed by Oakley Greenwood/enerNOC.

As a share of peak demand, economic DR in the Electric Reliability Council of Texas (ERCOT) is higher than that in the New York and the Midwest power markets. ERCOT is an energy-only market like the NEM; unlike the other markets compared in Table 1, ERCOT does not offer additional incentive payments along the lines of the DRM to customers offering DR.

Table 1. Estimated (actual) reliability and economic DR in selected US markets (2011)

	ERCOT	PJM	New York ISO	Midwest ISO	ISO NE
Reliability DR (MW)	~2,400	8,548	2,498	7,376	1,528
Economic DR (MW)	~600 (2010 est.)	2,334	278	547	1,227
Total DR (MW)	3,000	10,882	2,776	7,923	2,755
Peak demand (MW)	68,379	144,644	33,035	110,500	28,130
Total DR / peak demand	**4.4%**	**7.5%**	**8.4%**	**7.2%**	**9.8%**
Economic DR / peak demand	**0.9%**	**1.6%**	**0.8%**	**0.5%**	**4.4%**

Source: PJM 2012; Zarnikau 2010. Potomac Economics 2012a, 2012b, 2012c. 'FERC: Electric Power Markets - National Overview', n.d. http://www.ferc.gov/market-oversight/mkt-electric/overview.asp.

IEA XIII report

The Australian IEA Task XIII Study (2006) referred to in the Draft Report projects a potential DR from C&I customers of 2,289MW or 1,580MW by the summer and winter of 2025, respectively. The modelled DR would take the form of a 'callable' response, which appears to refer to reliability DR from load shedding or relying on stand-by generation.

There is no indication what share of the response would be accounted for by price responsive customers (which would be relevant for assessing the potential take-up of the DRM). Moreover, and while the analysis identifies a number of wider system cost savings from DR, there is no indication that any of the associated direct and opportunity costs that customers would incur have been considered in developing the potential DR forecasts (for instance by modelling different uptake rates depending on the type of customer). These projections would therefore be speculative and overstate the extent of economic DR that can realistically be expected in the NEM.

EPRI 2009

The Draft Report refers to a 2009 EPRI study to suggest that the achievable potential of demand response of C&I users is around 4.7 to 6 per cent of system peak demand. However, the figures that are cited refer to the combined effects of peak demand reductions that would be achievable by *all* customers types (residential, commercial and industrial) and for *all* DR programs combined. For the purpose of assessing the potential of the DRM to elicit economic DR from C&I customers, only a subset of these aggregate DR estimates are relevant. Table 2 highlights that price responsive DR from C&I customers was estimated at only around 0.2 per cent in 2010, and is forecast to amount to 0.7 per cent by 2020.

Table 2. Summer peak demand savings from price response DR (United States) - realistic achievable potential

	2010	2020	2030
Price response:			
Residential (MW)	1,539	6,918	10,967
Commercial (MW)	771	4,018	8,368
Industrial (MW)	515	2,765	5,697
Total price response (MW)	2,825	13,701	25,032
Total price response as a percentage of peak	**0.3%**	**1.4%**	**2.2%**
C&I price response as a percentage of peak	**0.2%**	**0.7%**	**1.3%**

Source: EPRI 2009.

3.3 Pilot studies and surveys of economic DR programs

The Draft Report refers to analysis by Futura Consulting (2011) to say that domestic and international trials show that time varying prices can achieve peak demand reductions of up to 30 or 40 per cent.

However, the results of pricing trials have to be interpreted with caution. Voluntary pricing trials suffer from what is referred to as 'self-selection' bias because they attract participants who stand to gain from a particular pricing approach. Important trial findings, such as estimated price elasticities are therefore generally not representative of the wider population. In addition:

- Australian studies of business customers' price responsiveness found no effect; and
- US estimates of C&I customers' price responsiveness vary widely. Customers with on-site generation are relatively price responsive, but most other types are far less so. The evidence instead suggests that demand shifting is the main form of response.

3.3.1 Customer participation and self-selection bias

The potential economic DR for a given electricity pricing structure (such as RTP or CPP pricing) depends on two inter-related factors:

- the rate of participation: the extent to which consumers can be induced to enrol in an economic DR program that implicitly or explicitly commits them to curtailing their electricity consumption; and
- the actual reductions in demand that customers achieve.

With few exceptions, DR pricing trials undertaken to date have relied on volunteers who have elected to 'opt in' to the trial. Whether a customer participates in a voluntary electricity pricing trial will depend on whether they expect to benefit (or at least will not be harmed) from the type of tariff that is on offer. For instance, given a choice, customers that either mainly consume electricity during off-peak periods or can easily shift their consumption will likely prefer a TOU tariff to a flat rate; conversely, customers with a standard load profile will likely prefer to stay on a flat rate. Trials of alternative pricing structures that enlist participants on a voluntary basis therefore suffer from 'self-selection' bias in the sense that, depending on the pricing design, they will attract participants who will benefit from that design. Additionally, voluntary electricity pricing trials typically incorporate an upfront 'incentive' payment to encourage consumers to participate and/or are designed such that electricity bills are no higher than under the status quo (EPRI 2008a). For these reasons rates of participation in voluntary trials are generally higher than in 'real life' programs, and estimates of potential demand reductions observed in particular trials are generally not representative of the broader population.

The difficulty of determining customer participation outside of a voluntary trial setting is well known (EPRI 2008a). There are few in-depth studies about which participant characteristics are associated with participation in economic DR programs. However, the results from recent US electricity pricing trials that have largely avoided a voluntary design suggest that self-selection may be an issue:

- Two recent large and well-designed trials analysed the DR of residential customers on RTP tariffs in Commonwealth Edison's Chicago supply area. The first applied an 'opt-in' recruitment approach and found a statistically significant price elasticity of demand of -0.1 (Alcott (2011). The second applied an 'opt-out' approach and found no statistically significant demand effects (EPRI 2011).

- In a large-scale field study of mandatory TOU pricing for C&I customers in Connecticut, no statistically significant change in aggregate average or peak consumption could be found following the introduction of TOU pricing (Jessoe and Rapson 2011).

3.3.2 Type and magnitude of the price response

Over the last 20 years, a large array of economic DR programs have been trialled, in particular in the United States, but also in Australia. These programs differ along multiple dimensions that impact on the price responsiveness of customers, and which complicate comparisons of estimated demand responsiveness.

To interpret these studies it is necessary to be clear about the nature of a customer's DR. A DR can take the form of an absolute reduction in electricity consumption (a conservation effect, as measured by the price elasticity), a shift between time periods (a temporal substitution effect, as measured by the substitution elasticity), or both. The distinction is relevant because in circumstances where customers shift a significant amount of consumption to adjacent time periods, the initial demand reduction effect may be offset in part.

Australian trials

The Australian pricing trials that have investigated the impacts of TOU and DPP pricing on business customers found no demand reduction effect (Annex B). Trials for residential customers indicated that there were both demand reduction and demand shifting effects (see Figure 7).While a particular incentive or pricing structure may therefore have reduced electricity consumption and peak demand in some periods, at least in some trials it also had the effect of creating a (new) peak at a different time.

SP AusNet's field experiment does not seem relevant for assessing the potential DR impact of the DRM. The significant demand response reported by SP AusNet appears to reflect the fact that a number of customers switched to on-site generation, and that peak metered demand on five particular days would form the basis for a customer's network charges for a year. This would seem a significant commercial incentive for customers to cut their consumption on those five days.

United States trials

Annex C summarises estimated price and substitution elasticities from trials involving time-varying prices of C&I customers in the United States, including TOU, CPP and RTP trials.[6] Participation in all but one of these trials was voluntary:

- With the exception of customers with on-site generation or arc furnaces, which were estimated to have a price elasticity of (-) 0.27, the estimated price elasticities for most other customers was estimated to be quite low.

- Most C&I customers appear to have substituted some share of their consumption to adjacent time periods. Substitution elasticities differ widely and range from 0.05 to 0.27.

EPRI (2008b) note the wide variations in results, which they attribute to the heterogeneity of customers, such as by business activity, peak and overall consumption levels, and the availability of on-site generation equipment.

3.4 Conclusions

The estimates referred to in the Draft Report overstate the likely quantum of load response as a result of the proposed DRM.

Given that the proposed DRM is an economic DR program, comparisons with other economic DR schemes are relevant for the purpose of determining the potential response in the NEM. An analysis of DR in US electricity markets suggests that demand reductions from economic DR programs vary between markets, but generally represent a far smaller share of peak demand than the 6 to 8 per cent identified in the Draft Report. FERC's 2010 survey of DR initiatives suggests that reported potential peak load reductions for C&I customers on economic (pricing) DR programs accounted for 0.5 per cent of peak demand, and reported potential peak load reductions from C&I customers on RTP programs accounted for 0.1 per cent of peak demand.

The results of pricing trials that report large demand effects from dynamic electricity pricing approaches should be interpreted with caution. In general, the results are unlikely to be representative of the underlying population average. To date, Australian studies of business customers have found no price effect. US estimates of suggest that C&I customers' price responsiveness is generally quite low, but that substitution effects are significant.

[6] The quality of US trials, in terms of design and number of participants is very variable. There are also significant variations between the particular incentives present in the trials and the resulting estimates of price responsiveness (Joskow 2012).

4 Economic benefits and costs of the DRM

The Draft Report identifies a number of benefits that would flow from the implementation of the proposed DRM. A key benefit relates to lower generation and network investment costs from deferred investment requirements. The magnitude of this benefit depends on the size of the DR that the DRM could elicit. As set out in Section 3, the estimated 6 to 8 per cent of peak demand from the DRM referred to in the Draft Report is far higher than the share of economic DR reported in US wholesale power markets, and as estimated by FERC (2011) and EPRI (2009). Any likely economic benefits from the DRM would correspondingly be reduced.

This section examines the benefits and costs identified in the Draft Report in more detail. A number of the identified benefits raise wider questions that appear not to have been considered.

4.1 Reductions in spot prices and customer bills

The Draft Report states that a key 'benefit' of the DRM is that it could potentially reduce wholesale market spot prices, which would be passed on to customers in the form of lower retail prices.[7] The analysis in Section 2 explains that this is not the case. In a dynamic market setting, prices will adjust to account for the changed market risks associated with transfer payments to customers participating in the DRM. Furthermore, as set out in the following:

- price changes that transfer rents from one party to another do not constitute an economic benefit;
- policies that are designed to suppress high prices have negative longer-term consequences for investment in an energy-only market like the NEM; and
- the inherent attractiveness of the DRM to customers with on-site generation raises questions about the consistency of the DRM with NEM efficiency objectives.

4.1.1 Economic benefits versus transfers

Averaged electricity retail tariffs that do not reflect the cost of producing electricity at any one time give rise to a pricing or 'allocative' inefficiency, as pictured in Figure 5. In circumstances where the cost of production and the wholesale market price is high during peak hours, consumers who are presented with an average retail electricity price use 'too much' electricity, and vice versa. In either case, the inefficiency arises because consumers' marginal valuation of electricity is higher or lower than the marginal cost of producing it. In economic terms, this allocative inefficiency gives rise to a 'deadweight' loss: the difference between the consumers' marginal benefit and producers' marginal cost. In Figure 5, that deadweight loss is represented by the two circled triangles that arise when the price is 'too high' or 'too low'.

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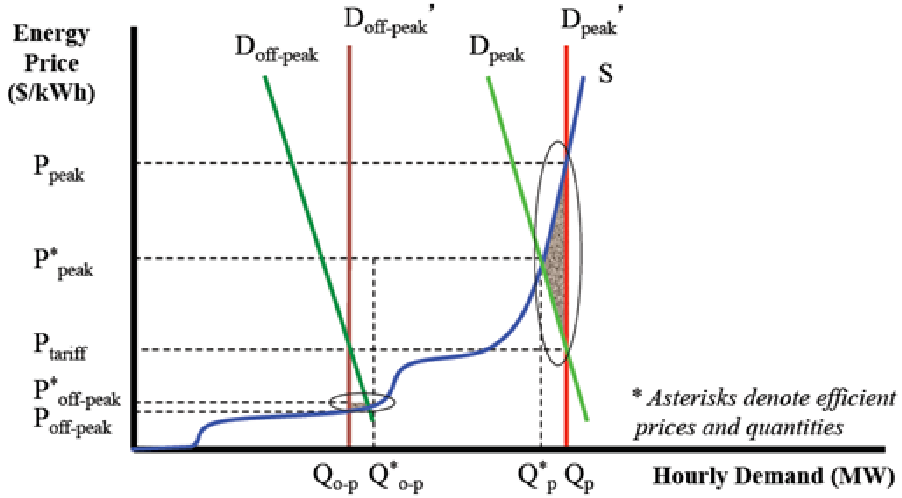
[7] Spot prices in the NEM in 2011-12 were lower in nominal terms than they were in 2001-02 in Victoria, New South Wales, Queensland and South Australia (AEMO 2012).

Figure 5. Economic cost of averaged retail tariffs (pricing inefficiency)



Source: Borlick, Robert L. 2012. Demand Response & Energy Efficiency in Wholesale Power Markets, EEI Transmission and Wholesale Markets School, August 7.

The deadweight loss is not the same as the reduction (or increase) in prices and resulting bill changes. Price changes only redistribute the gains from trade between market participants, in this case from producers to consumers. Economics draws a clear distinction between economic benefits and (wealth) transfers. (Net) economic benefits improve societal welfare; transfers only change the distribution of these benefits.

The distinction between economic benefits and transfers is also reflected in the regulatory investment test for transmission (RIT-T), which is intended to support efficient investment (AER 2010). In the context of the RIT-T, market benefits include a range of (real and credible) avoided costs such as from reductions in fuel consumption, load curtailments, deferred investments and others. Market benefits explicitly do not include the transfer of surplus (or rents) between consumers and producers.

4.1.2 Price spikes in the NEM

Specifically in the context of the NEM, policies aimed at reducing wholesale market prices are not consistent with dynamic efficiency objectives. The success of the energy-only market design critically depends on (infrequent) high prices that incorporate 'scarcity rents' when capacity is tight, to enable generators to recover the costs of their fixed power plant investments (Stoft 2002).[8] Unlike markets such as PJM and the New York and New England wholesale markets (which have adopted mechanisms similar to the DRM), the energy-only market design of the NEM does not incorporate payments for generator capacity or availability. NEM generators are instead reliant on differences between spot market prices and variable generating costs to recover their fixed costs. Market interventions that dampen or eliminate higher priced periods therefore reduce revenues to existing generators and impair longer-term investment incentives. As stated by the Independent Market Monitor for the ERCOT Wholesale Market (Potomac Economics 2012, P., xxi):

[8] Scarcity generally refers to a situation where the demand curve intersects the supply curve on the (near) vertical section close to maximum output. Under these conditions, generation capacity is scarce and earns 'scarcity rents' – the excess of revenue over short run marginal costs.

> *The energy-only market design relies upon these relatively infrequent occurrences of high prices to provide the appropriate price signal for demand response and new investment when required.*

4.1.3 Customers with on-site generation

A uniform theme in the literature on economic DR programs that rely on a consumption baseline approach is that a significant part of the DR is provided by customers with on-site generation, and that the baseline approach encourages opportunistic investment in on-site generation. The CAISO Market Surveillance Committee recently reported on its concerns with the rapidly increasing installation in California of 'behind-the-meter generation' in the form of 'Bloom Boxes' (CAISO 2011). Bloom Boxes were being installed as a form of demand reduction by entities such as Google and would soon be available in a residential setting. Rather than turning off an air conditioner when spot prices were high, DR providers were using small fuel cells while leaving the air conditioner running.

It might be argued that on-site generation could contribute to reducing peak demand and defer the cost of additional system capacity, consistent with the objectives of the DRM. However, a number of broader issues are also relevant:

- In the absence of the DRM, the level of on-site capacity put in place by users would equate the costs of the back–up generation with the expected opportunity costs of a power outage or shortfalls, or alternatively reflect the value of combined power and steam production processes. All things equal, the DRM strengthens customers' incentives to invest or over-invest in on-site generation. From a system perspective, it is doubtful whether this additional investment in small-scale generating units would be more cost effective than investing in larger scale generation capacity.

- If on-site generation frequently displaces higher priced bids from NEM generators, infra-marginal rents earned by all other generators operating in the NEM may be reduced, and legitimate price signals to indicate a capacity shortage may be dampened. These effects raise concerns about the ongoing viability of existing generating businesses and the ability of the market to attract future investment. More generally, they highlight that changes in market design affect price duration curves (thereby changing revenues to NEM market participants), and represent a source of sovereign risk.

- A final concern relating to customers with on-site generation concerns the observation that these types of customers are in a good position to inflate their baseline (Section 1.1), and thereby increase the eventual costs of the scheme to consumers for little or no corresponding DR.

Given these concerns, it is relevant that the AEMC is in the process of developing a Small Generation Aggregator Framework (AEMC 2012b). The proposed rule change would enable small generators to participate in the NEM and operate as peaking plant. This proposal would seem to avoid the adverse incentive effects of the baseline approach by treating on-site generation more appropriately as generation rather than as DR.

4.2 Benefits from deferred generation and transmission investment

The potential benefits from deferred generation and transmission investment depend on the quantum of demand reduction that the DRM could elicit. As set out in Section 3, there are a number of reasons why the likely level of DR in the NEM is likely to be far lower than estimates in the Draft Report suggest. Estimates of deferred investment benefits will also depend on a number of other assumptions, namely that:

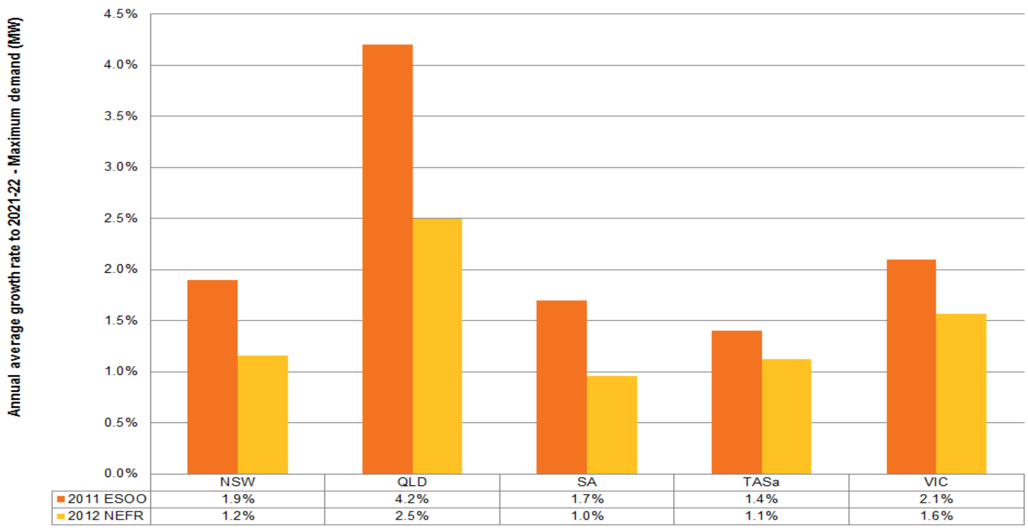
- historical growth in peak demand in the NEM has been high and will continue to be high;
- achieved reductions in peak demand are not offset by temporal shifts in consumption;
- demand reductions that are achieved are predictable and will persist at an acceptable level of reliability; and
- for network investment, that regional system peaks coincide with network peaks.

4.2.1 NEM peak demand trends

AEMO's most recent demand and consumption forecasts in the 2012 ESOO represent a very significant downward revision of its historical demand forecasts (Figure 6):

- Reduced growth in energy use is expected to defer new generation or demand side investment for at least four years to 2018-19, compared to the forecasts in the 2011 ESOO.
- AEMO's forecast annual average energy growth rate for the NEM has been reduced from 2.3 per cent to 1.7 per cent.
- Projections of maximum demand have been reduced for all regions. Forecast annual average peak demand growth in Queensland (historically the state with the highest rate of growth) have been cut from 4.2 per cent in the 2011 ESOO to 2.5 per cent in the 2012 ESOO. Peak demand in all other regions is now projected to grow between 1.0 and 1.6 per cent per year.

Figure 6. Comparison of NEM average annual maximum demand projection growth rates – 2012 ESOO versus 2011 ESOO (medium growth scenario)



Source: AEMO 2012. Electricity Statement of Opportunities.

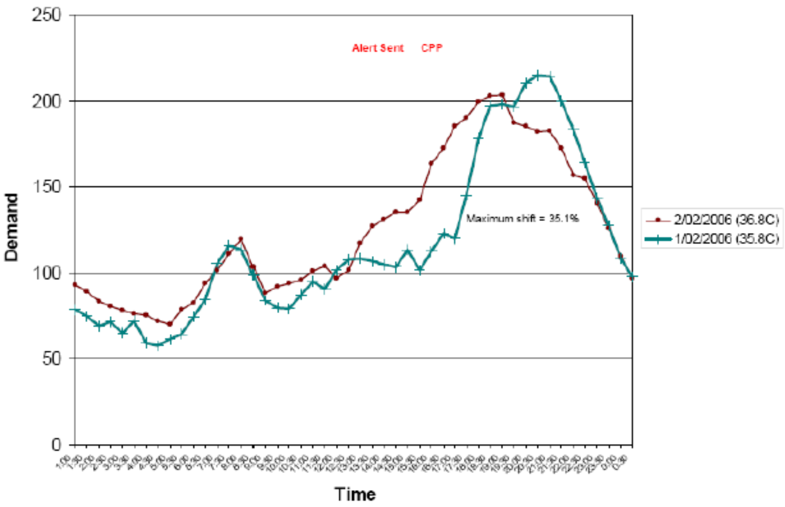
These significant changes highlight the degree of uncertainty surrounding current NEM demand forecasts, and how the changed forecasts will affect investment needs going forward. At least from an aggregate NEM-wide and regional perspective, there are indications that the rate of peak demand growth may have already slowed in recent years, so that these recent reductions may reflect a longer term trend (Annex C).

4.2.2 Demand reduction versus demand substitution

If a DR creates a sufficiently large substitution effect, it may reduce consumption during critical peak hours, but also create a new demand peak at a different point in time. To the extent to which it encourages temporal substitution, the value of the DRM may therefore be reduced.

Statistically significant demand substitution effects were identified in most US trials of C&I customers (Annex C). The Australian studies described by Futura Consulting (2011) do not appear to systematically investigate substitution effects, although they are present in at least two studies (of residential customers), including Country Energy's CPP trial (Figure 7).

Figure 7. Country Energy CPP trial – substitution effect



Source: Futura Consulting 2011.

4.2.3 Reliability and predictability of economic DR

The Draft Report is careful to emphasise that any demand responses from the DRM would need to be sustained and predictable to result in cost savings. Generation and network investments require significant lead times, not just for the construction of the project, but also to complete planning and approval processes. From a planning and reliability perspective, bodies such as AEMO and TNSPs would need to consider whether load responses are sufficiently reliable to be incorporated in planning and investment decisions.

As a general matter, it is questionable whether DR resulting from the proposed DRM would meet this test (Bushnell et al. 2009). Participation in economic DR programs such as the DRM is entirely voluntary and not financially binding. Participation would also depend, among other things, on customers' opportunity costs and business conditions (Section 3.1). This effect would tend to make the DR countercyclical, since C&I customers would be less likely to offer DR during good economic conditions than during downturns. Paradoxically, therefore, the DR would likely be less forthcoming when it was needed most. Finally, the difficulties associated with defining a robust customer baseline imply that demand reductions would not be verifiable in many cases.

As set out in the following:

- as best as can be told, no systematic analysis of the predictability or reliability of economic DR has been done to date; and
- to the extent that there are material concerns about customers' ability to manipulate the baseline, claimed load reductions will be discounted by system and network planners.

Experience in US power markets

Little is known about the extent to which economic DR schemes can be considered sufficiently reliable to form the basis for long term investment plans. NERC has only recently developed and implemented consistent metrics to assess the performance of reliability DR. Metrics to assess the performance of economic DR in a consistent manner do not as yet exist in North America (NERC 2012). NERC does not incorporate economic DR arising from demand bidding or dynamic pricing in its reliability assessment.

Only one other study appears to have investigated the performance of (voluntary) economic DR programs in the United States (Cappers et al. 2009). Relatively little data was available to assess customer responses, but significant year-on-year variability was observed in the case of ISO-NE's economic DR program.[9] Over four years, participants' load reductions were about 32 per cent of their subscribed commitment during high price events, and varied from a low of 9 per cent to a high of 53 per cent.

Incentive effects of the baseline

The ability of certain types of customers to manipulate the baseline implies that at least some share of any demand reductions is illusory. The implications of these adverse incentive problems are far-reaching and substantially undermine any claimed reliability benefits from DR schemes that rely on a baseline (Bushnell et al. 2009). Because it results in inflated estimates of and payments for price responsive demand that turn out to be non-existent, system operators and planners will discount the reliability of price responsive demand and therefore its value. No system (generation and transmission) costs will be avoided in circumstances where planners have good reason to doubt whether any deemed DR is in fact 'real'.

4.2.4 Coincidence of network and system peaks

An expectation that the DRM will serve as an effective tool for postponing transmission and distribution investment presupposes that regional or system-wide peaks in demand and prices will coincide with zonal or local peaks, as they affect distribution and transmission assets. However, loads at a feeder level are highly specific to the type of customers (residential, commercial or industrial) located there. At a more aggregated geographical level, local or zonal peaks will furthermore be shaped by distinctive weather conditions. These factors will feed into peak demand trends at a wider area or zonal level.

[9] The performance of reliability DR is also not guaranteed. The ISO-NE Independent Market Monitor notes that, when demand response resources were deployed, their performance varied widely (Potomac Economics 2012a). Often only a small portion of resources curtailed an amount of load within 10 per cent of the instructed amount. According to the market monitor, these results raise significant concerns about whether the demand response resources selling capacity in New England provide the same level of reliability benefits as generators and imports.

The extent to which local or zonal demand coincides with regional demand peaks and therefore prices (so that an effective DR might defer network investment) will depends on the extent of variation across the state. In the case of Queensland, for instance weather and load patterns across the state are diverse (Powerlink 2012). Powerlink forecasts demand across 10 geographical zones, each of which experiences its own zone peak demand, which typically does not coincide with the time of maximum demand for the whole Queensland region. These divergences will be greater at lower levels of aggregation (for instance, distribution versus transmission).

4.3 Direct implementation and ongoing costs of the DRM

The Draft Report states that implementing the proposed DRM would entail some costs to the market, but considers that most of these costs would be administrative in nature: new procedures and guidelines for registering demand resources, changes to the settlement process, as well as program monitoring and reporting costs during the initial years of operation.

It is not clear, whether the above characterisation of the costs of the DRM captures the range of costs that would be incurred. An economic analysis of a policy proposal such as the DRM would require that all implementation costs be considered, irrespective of which party bears them and how they would be recovered. These costs include all costs incurred by AEMO, participating customers and load aggregators, as well as those incurred by other third parties such as regulators.

The following sections discuss the economic costs that would likely be incurred in the course of implementing and operating the DRM. In addition to the specific cost categories described below, the costs associated with the necessary industry consultation processes would also need to be considered. These would include the costs of developing and refining various aspects of the DRM, for instance the approach used for estimating the baseline, the engagement of expert advisors, and the operation of working groups to resolve ongoing issues.

4.3.1 Consumption baseline

Developing consumption baselines will almost certainly represent a significant cost for AEMO, in terms of the time and resources required to develop the baselines, the required interactions with customers or load aggregators, the ongoing monitoring processes that will be required, and the potential for settlement or other disputes.

As discussed in Section 2, the experience in the United States suggests that determining customer baselines for a diverse set of customers spanning different sizes, industry sectors and locations is a significant analytical and data- and time intensive task. In US power markets that have adopted a similar approach, a large amount of analysis has had to be done over the years to better account for customer size, variability, weather sensitivity and many other factors. Given the ongoing difficulties with the baseline approach, these processes are continuing. The baseline approach requires processing voluminous datasets of interval load and climate data over multiple months or years from multiple customers dispersed across geographical zones (Woo and Herter 2006). For instance, a 15-month pricing experiment in California conducted in 2006 generated around 22 million hourly load data values and over 600,000 temperature values for the 2,000 participating customers in four climate zones.

In the United States, concerns about baseline gaming have required regulatory staff in individual markets to dedicate considerable time and resources to developing screens to identify questionable DR submissions, and to undertake ex post reviews to assess and report on the operations of the baselines. The need to determine consumption baselines on an individual customer basis has also resulted in a new source of disputes, namely between scheme administrators and customers and/or load aggregators. Where these cannot be resolved or fraud is suspected, the regulator must get involved. Ongoing difficulties in the accurate measurement of reliability and economic DR, as well as questions about the cost-effectiveness of any achieved demand reductions have additionally led to a requirement on the industry to develop new DR metrics and mandatory reporting protocols (FERC 2011).

4.3.2 Settlements processes

AEMO currently provides a market settlement, billing and clearing service to NEM participants. In the course of these activities, AEMO processes aggregate metering data provided by metering data providers (MDPs) to determine participants' liabilities.

The proposed DRM inserts additional parties and associated processes between 'traditional' NEM settlement processes between retailers and generators or customers. Rather than retailers' purchases being entirely settled on the basis of customers' actual consumption (as determined by representative aggregate load profiles at various bulk connection points), AEMO or some other party would be required to adjust individual retailers' bills by the difference between participating customers' specific consumption baseline and actual meter readings. This process would have to be undertaken for each participating customer's baseline. It seems plausible that this process would require software and procedural changes to enable AEMO to make the necessary adjustments to the raw metering data.

4.3.3 Meters and associated infrastructure

The proposed DRM would require half-hourly customer consumption data for developing the consumption baselines, and to determine the extent of any DR. Baseline data would need to be collected for all customers participating in the DRM, but also for non-participating customers who would be required as a (statistical) control group (KEMA 2011). To the extent that customers do not already have these, gaining access to such data may therefore require the widespread installation of interval meters, as well as the associated communications, and data management and storage systems. Customers participating in the DRM may also need to install energy management systems and/or control capabilities. These upfront expenditures on equipment and infrastructure could potentially be very costly.

4.3.4 Load aggregators

Load aggregators would incur personnel, systems and communications costs in order to build up a portfolio of DR customers and offer demand responsiveness on their behalf. These costs would include the costs of:

- identifying, negotiating with and contracting with suitable customers;
- assisting customers in the processes required for establishing a customer-specific baseline, such as organising historical data and negotiating with AEMO;
- depending on the sophistication of any DR services, establishing and operating communications and/or notifications systems with participating customers; and
- putting in place the billing and settlement systems to distribute payments from AEMO to participating customers.

4.3.5 Regulators

It seems certain that regulatory involvement would be required to oversee the operation of the DRM. As discussed in Section 1.1, the application of DRM-type mechanisms in the United States has been contentious, and has required ongoing supervisory processes to be developed by market monitoring agencies and the intervention of regulators. Baseline approaches have been modified repeatedly in the various markets applying a similar mechanism, requiring new public consultations as part of regulatory approval processes.

4.4 Conclusions

The Draft Report identifies a number of potential benefits from the proposed DRM that are questionable:

- Lower wholesale market prices do not constitute an economic benefit to society. They instead represent transfers that come at the expense of producers. In any case, the DRM would not lower wholesale market prices, but would instead lead to consequent adjustments in the price of hedge contracts. These higher wholesale market costs will be passed on by retailers in the form of higher retail prices, so that the eventual cost of the DRM will be borne by consumers.

- Cost savings arising from deferred generation and network investment depend on the level of DR that the DRM could elicit. This is likely to be substantively lower than estimated in the Draft Report. In addition, the effectiveness of DRM in reducing generation and particularly network costs depends on a number of other factors that are not well understood, namely:

  - whether currently identified network investment requirements beyond the current set of price controls are still required, given significant downward revisions in NEM peak demand and consumption trends, and given that peak demand growth appears to have been slowing

  - the extent to which any demand reductions as a result of the DRM may be reduced by substitution effects, which may create stresses elsewhere in the system;

  - the predictability and ongoing sustainability of economic DR, which is unknown at this point in time; and

  - the extent to which regional demand and pricing peaks coincide with local network peaks, and therefore whether a price response targeted at the system peak will be effective in addressing local network constraints.

Finally, the economic costs of implementing the DRM in the NEM are potentially very significant. They include:

- the costs of market consultations, the engagement of expert advisors, and ongoing working group and other processes;

- the costs of determining and monitoring consumption baselines, including associated significant data processing requirements;

- to the extent that they do not have them, the costs of installing interval meters and associated infrastructure to participating and non-participating customers (required for the purpose of establishing a statistical control group), as well as any additional costs incurred by customers;
- any changes to existing NEM settlements processes;
- the costs incurred by load aggregators to establish and run their operations; and
- significant regulatory monitoring and oversight costs, as well as the costs of resolving disputes between the scheme administrator and participating customers.

5 Conclusions

A final assessment of the merits of the DRM would need to reflect an evaluation of the additional DR which this mechanism could deliver, and the associated economic benefits and costs.

The Draft Report states that the proposed DRM would reduce wholesale and retail market prices. However, under any realistic scenario the DRM would instead increase these prices so that its costs would be borne by consumers as a whole. Wealth transfers from producers to consumers can also not be considered to be a 'benefit' in any economic sense.

The economic benefits from the proposed DRM would consist of avoided (short- and long-run) generation and network costs. The magnitude of these benefits is likely to be less than might be expected. The Draft Report significantly overestimates the likely quantum of DR in the NEM. Other factors that would tend to reduce the value of demand responses from the DRM as a longer term planning resource (such as demand substitution effects, the reliability of economic DR, and the diversity of network and system peaks) appear not to have been fully considered. To the extent that some share of DR is based on inflated baselines, the economic benefits of the DRM will be further reduced.

The Draft Report does not include the full range of costs that would need to be considered. All demand responses impose an opportunity cost on customers, whether this takes the form of a loss of comfort or convenience for a residential consumer, or a loss of output or similar for a business customer. Estimates of the implementation and ongoing costs of the DRM would also need to include the costs of associated consultation and administrative processes, the costs associated with determining and monitoring baselines, any additional equipment and infrastructure costs, the costs of any changes to NEM settlements processes, the costs incurred by load aggregators, and regulatory monitoring and oversight costs.

All of the above considerations suggest that the benefits of the DRM are likely to be overstated, and that its costs would be higher than anticipated. Additionally, the DRM would disrupt the operation of NEM wholesale markets, result in rising retail prices for consumers, and raise concerns about the equitable treatment of consumers. The overall net economic benefit of the DRM cannot be determined without an independent and robust review of the direct and indirect consequences of this mechanism.

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Annex A Dynamic equilibrium calculation

	Business-as-usual (equilibrium)	Business-as-usual, with DR (equilibrium)	DRM with DR, no price adjustment (disequilibrium)	DRM with DR, with price adjustment (new equilibrium)
Quantities:				
Baseline (MW)	10	10	10	10
Actual consumption (MW)	10	8	8	8
Demand response	0	2	2	2
CFD volume	10	10	10	10
Prices:				
CFD strike price	$50	$50	$50	$50
Spot price	$1,000	$1,000	$1,000	$1,000
CFD price ($/MW)	$0	$0	$0	$190
Retail price ($/MWh)	$50	$50	$50	$240
Generator:				
Spot market revenues	$10,000	$8,000	$8,000	$8,000
Contract revenues	$0	$0	$0	$1,900
CFD difference payments	-$9,500	-$7,600	-$9,500	-$9,500
Profit/loss	$500	$400	-$1,500	$400
DRM transfer			-$1,900	$0
Retailer:				
Spot market payments	-$10,000	-$8,000	-$10,000	-$10,000
Contract payments	$0	$0	$0	-$1,900
CFD difference revenues	$9,500	$7,600	$9,500	$9,500
Customer receipts	$500	$400	$500	$2,400
Profit/loss	$0	$0	$0	$0
DRM transfer		$0	$0	$0
Customer:				
DR Income	$0	$0	$2,000	$2,000
Value of electricity received	$500	$400	$400	$400
Retailer payments	$500	-$400	-$500	-$2,400
Profit/loss	$0	$0	$1,900	$0
DRM transfer		$0	$1,900	$0

Annex B Overview of Australian DR trials – Futura Consulting (2011)

Utility	DR pilot	Date	Total number of participants	Incentive payment per participant	Demand/energy reduction	Dispatch events	Average take-up
TOU tariffs							
Ausgrid	AMI Phase I	2006-2009	3,000 residential/ SMEs	n/a	Residential: (-)4% peak demand Business: no reduction	n/a	n/a
STOU/DPP tariffs							
Essential Energy	HEET DPP	2004	150 residential	$40 per quarter	(-)25% demand on DPP days (-)8% consumption	12 max	n/a
Endeavour Energy	WSPT STOU	2006-2008	295 residential	$100 credit to join, $200 at trial end	not quantifiable	n/a	15%
	WSPT DPP	"	729 residential	$100 credit to join, $200 at trial end	(-)35% peak demand (1kW)	12 max	n/a
Ausgrid	SPS STOU	2006-2008	750 residential, 550 business	$100 to join, $200 at trial end	Residential: (-)5%-13% peak demand Business: no reduction	n/a	10% residential, 5-6% business
	SPS DPP			$100 to join, $200 at trial end	Residential: (-)23-25% peak demand Business: no reduction	12 max	10% residential, 5-6% business
	BSC DPP		264 residential	$25 to join, $100 at trial end	n/a	n/a	10% residential, 5-6% business
PTR							
Endeavour Energy	n/a	2010-11	39	$1.50/kWh for reduction below baseline, up to $50 per event day	(-)29% -51% peak demand	4	n/a

Notes: TOU refers to time-of-use, PTR refers to peak time rebate, STOU refers to TOU + demand adjustment, DPP refers to a critical peak period (CPP) tariff overlaid with a two-part TOU tariff.

Source: Futura Consulting (2011)

Annex C US elasticity estimates for time-varying pricing plans, C&I customers

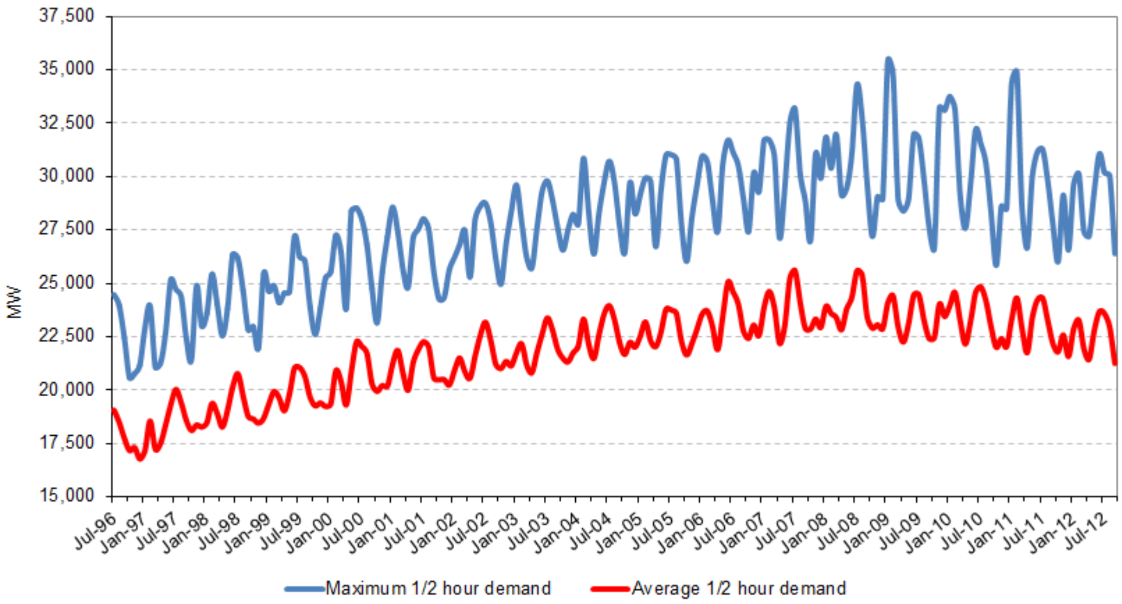
Type of program	Segment	Year/location	Elasticity estimates
TOU for demand / energy*	Large C&I	1978-80, California	OPE: -0.02 to -0.09 for peak demand
TOU for demand / energy	Small/medium C&I (20kW-500kW)	1980-82, California	ES: 0.11 for summer demand for large customers (200-500kW) ES: 0.04 for summer demand for overall customers (0-500kW)
TOU for demand / energy	Large C&I	1976-77, Midwest	OPE: -0.014 for peak demand
CPP variable	Small C&I	2003-04, California	ES: 0.05 for consumers with demand < 20kW ES: 0.06 for consumers with demand 20kW - 200kW
Day-ahead RTP	Large industrial (2mw-30MW)	1985, New York	ES: 0.09
Day-ahead/ hour-ahead RTP	Large C&I (> 1MW)	1998-2001, Minnesota	ES: 0.1-0.18 for day-ahead RTP ES: 0.2-0.27 hour-ahead RTP
Day-ahead RTP	Large C&I (> 1MW)	1994-2001, North & South Carolina	OPE: -0.27 for peak periods for customers with on-site generators or arc furnaces OPE: -0.03 for all other customers
Day-ahead RTP	Large industrial (>1MW)	1994-1999, North & South Carolina	ES: 0.04
Day-ahead RTP	Large C&I (2MW-20MW)	2000-04, New York	ES: 0.16 for manufacturing ES: 0.06 for commercial/retail
Day-ahead RTP	Large industrial (2MW-30MW)	1985, New York	ES: 0.09 for aggregate hours

Notes: OPE refers to own price elasticity. ES refers to the elasticity of substitution of off-peak for peak energy. * mandatory pricing trial.

Source: EPRI 2008b.

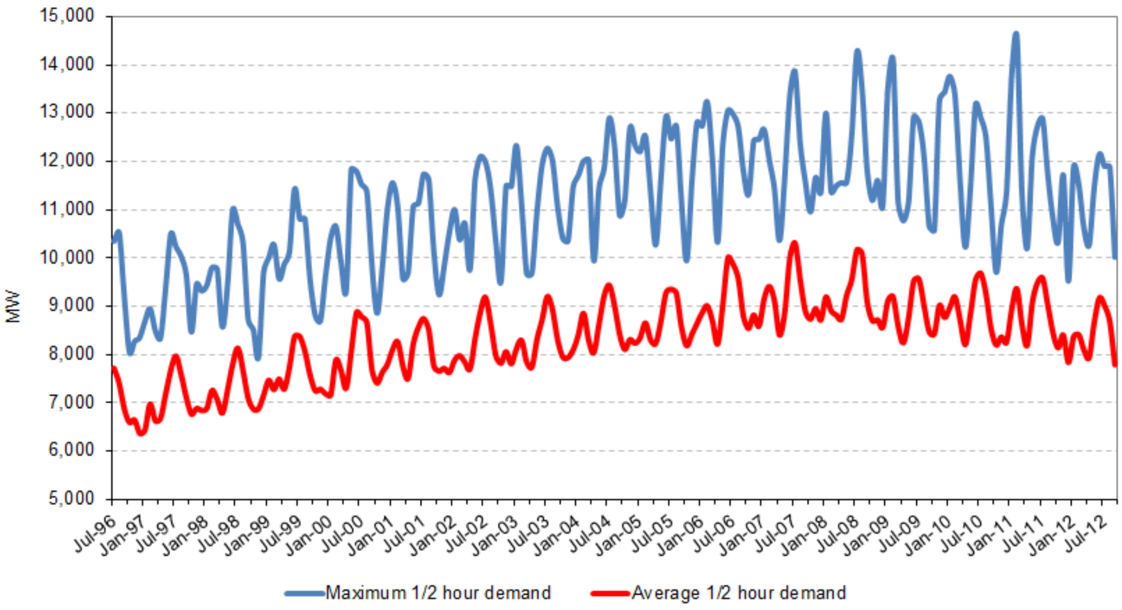
Annex D Historical half-hourly monthly peak and average demand

Figure 8. NEM half-hourly monthly peak and average demand (1996-97 to 2011-12)



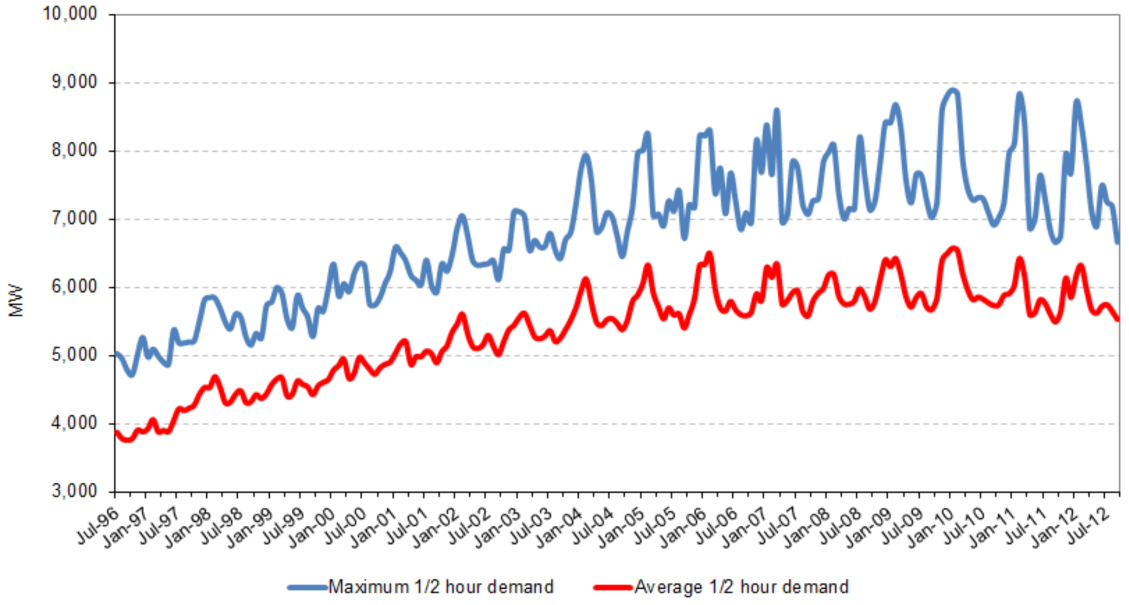
Source: AEMO data.

Figure 9. New South Wales half-hourly monthly peak and average demand (1996-97 to 2011-12)



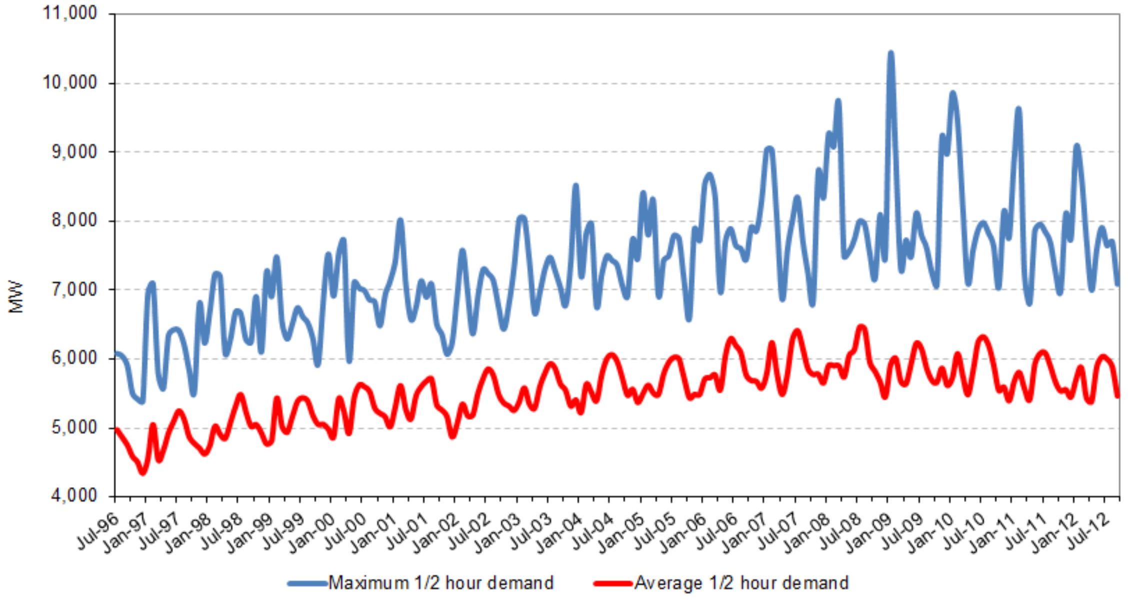
Source: AEMO data.

Figure 10. Queensland half-hourly monthly peak and average demand (1996-97 to 2011-12)



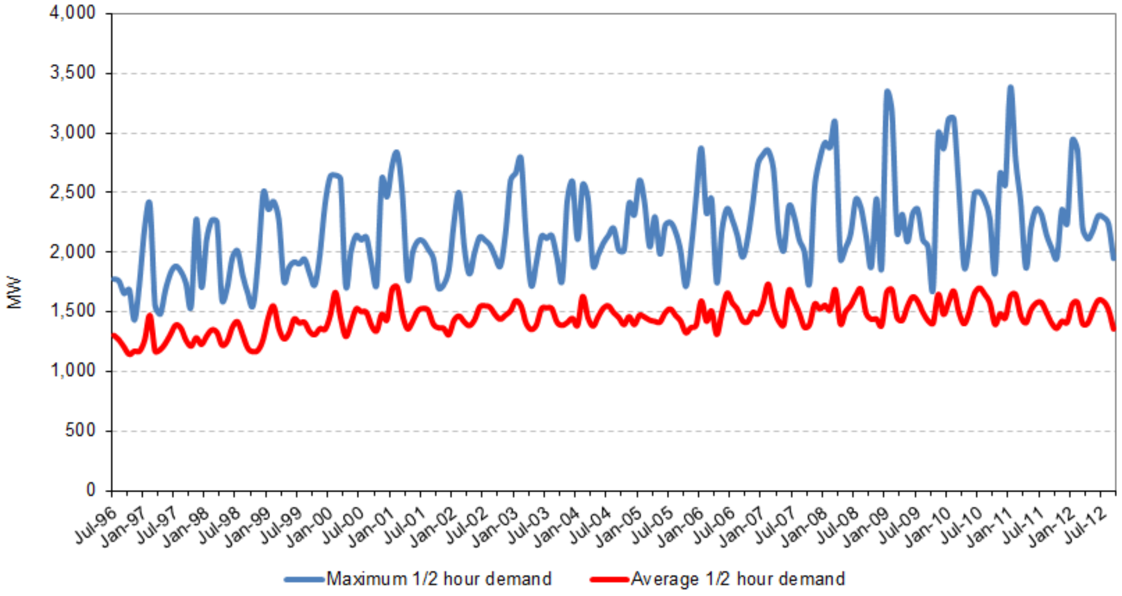
Source: AEMO data.

Figure 11. Victoria half-hourly monthly peak and average demand (1996-97 to 2011-12)



Source: AEMO data.

Figure 12. South Australia half-hourly monthly peak and average demand (1996-97 to 2011-12)



Source: AEMO data.