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Australian Energy Market Commission
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11 October 2012

Dear Commissioners Pierce, Henderson, Spalding,

Response to Power of Choice Draft Report (EPR0022)

EnerNOC Pty Ltd appreciates this opportunity to lodge a further submission to this important market review.

The Draft Report and the draft recommendations contained therein are largely excellent. In particular, the draft recommendation to introduce demand-side bidding is extremely welcome, and the Draft Report explains the rationale for its introduction very clearly.

There are two areas in which we believe that the proposed reforms could be further improved: introducing targets for network businesses, and resolving timing issues that create inefficiencies in the wholesale market.

There are three parts to our submission:

- This letter discusses these two areas in which the draft recommendations could be improved.
- Appendix A addresses some misconceptions which seem to have arisen regarding demand-side bidding. The errors are fairly obvious, but we believe it would be helpful to spell them out.
- Appendix B contains our comments on the issues raised in the Draft Report, along with answers to those of the questions asked by the AEMC which are relevant to our expertise.

Targets for network businesses

The Draft Report includes insightful analysis of the incentives actually faced by regulated network businesses, and how they cause perverse outcomes with respect to DSP. However, the draft recommendations stop short of fixing three key issues in the regulatory regime:

- The differential treatment of capex and opex.
- The coupling of revenue with throughput (except in Queensland).
- The overestimation of the WACC for state-owned businesses.

These issues all inhibit network businesses from choosing to use DSP as part of their normal business practices. If they are left unresolved, then businesses will continue to do very little DSP as part of their normal planning and business practices.

Hence, the potential for network businesses to carry out an efficient level of DSP hinges entirely on the design of the proposed reformed demand management incentive scheme ("RDMIS", to distinguish it from the previous DMIS and DMEGCIS which, despite their names, were not really incentive schemes, and achieved little).

We should expect almost all network-led DSP to take place through the RDMIS, since this is the only way that network businesses will be able to avoid the continuing disincentives and receive appropriate incentives.

While this is a second-best outcome compared to fixing the underlying distortions in the regulatory model, and will lead to a higher administrative burden, for which the businesses should be compensated, it may be workable.

The Draft Report briefly considers a few types of targets which could be imposed on network businesses, before concluding that it is best not to set any targets, due to the risk that network businesses may invest inefficiently purely to satisfy a target.

We disagree with this conclusion, as there is an easy way to avoid this risk: to count towards the fulfilment of the target only those projects which are covered by the RDMIS. Since the RDMIS should be designed such that only efficient projects qualify, this eliminates the possibility of networks investing inefficiently to meet the target, and forces them to find opportunities to invest efficiently, which is the desired outcome.

Targets are important, because they set expectations and focus management's attention. A regulated business can choose to ignore an incentive scheme, or make only a token effort to work towards it, if it clashes with its established business practices. Judging by the results of previous attempts to incentivise DSP, there is a risk of this happening with the proposed incentive scheme.

In general, there are two ways to ensure that management pays attention to an incentive scheme:

1. make the positive incentive particularly lucrative, or
2. include targets, and significant penalties if the targets are not met.

Both of these will work, but the combination of targets and penalties is the cheaper option. It also avoids the need to wind back an excessively lucrative positive incentive to a more sustainable setting once network businesses have embraced the new paradigm.

In particular, we would suggest that the target should be set on the proportion of forecast growth-driven expenditure which is avoided through RDMIS-approved DSP. The RDMIS itself should provide the necessary positive incentive for NSPs to pursue the most cost-effective DSP projects, so all that needs to be added is a penalty for not meeting the target.

The target should be set deliberately below the efficient level, so that it is clearly achievable. The RDMIS's positive incentive should encourage network businesses to carry out an efficient level of DSP, well above the target; the purpose of the target, and associated "stick", is to ensure that they cannot afford to ignore the issue altogether.

Timing issues in the wholesale market

Implemented on its own, the proposed demand-side bidding mechanism will for the first time introduce competition into the procurement of demand response for wholesale market purposes. As well as the direct benefits to consumers from the increased level of wholesale market participation that will result, there should be significant consequential benefits for network demand management. The costs should be very small in comparison to the benefits; it should be implemented as soon as practicable.

However, to allow the level of DSP to rise further, nearer to the efficient levels seen in markets with mature DSP mechanisms, further reforms will be needed. These are more wide-reaching than the demand-side bidding mechanism itself, so they clearly cannot be implemented in the same timeframe. They relate to a peculiarity in the design of the NEM which causes it to conflate the value of providing energy when needed with that of providing energy at short notice. This issue has been tolerated by generators since market start as a cost of doing business, but has a disproportionate negative impact on demand resources due to their much higher short-run marginal costs.

Some demand resources are able to dispatch at short notice, in 5-10 minutes or less.[1] These are customers whose operations are simple, or whose loads can be remotely controlled. Demand response on these terms is relatively expensive, because dispatching such resources tends to be disruptive. Increasing the notice period greatly increases the number of customers that can participate and the amount of demand response capacity that can be procured. Truly broad participation can be achieved if 1-2 hours of notice can be given.

Under the current market design, many generators avoid the economic dispatch process altogether. Instead of offering in capacity at some price vaguely related to their marginal costs, and allowing the dispatch engine to determine when they run, they instead "self commit", by choosing when they want to run, and bidding in their capacity near the market floor price for those periods, and near the market price cap for other periods.

This behaviour is evident from examination of supply curves: typically the supply curve is barely a curve at all: most of the capacity is offered at $0 or negative prices, and there is a substantial chunk up near the market price cap; very little is offered anywhere near marginal costs. The setting of the spot price is almost

[1] Some can respond more quickly than any generator – EnerNOC's portfolios in New Zealand and Alberta provide sub-second responses.

accidental, left to those few generators who allow themselves to be dispatched properly. This leads to extremely volatile price outcomes – temporary excursions to the market price floor or cap – when demand changes unexpectedly, and a reliance on frequent rebidding. This is not the behaviour of a well-functioning market.

This technique used by many generators – speculatively offering their capacity into the market significantly below their marginal cost in anticipation that higher prices will eventuate by the time that they actually start generating – is necessary because it is the only way that they can attempt to ensure that they are dispatched in time for a high-price period: if they rely on the dispatch engine, they will only be told to start at the moment that their energy is needed, not at the time that they need to start in order to provide energy when it is needed. It is not only slow-starting baseload generators that do this: relatively fast-starting peakers do it too.

Demand resources can have short-run marginal costs are one or two orders of magnitude higher than those of generators. For addressing extreme peaks in demand,[2] they are the lowest cost resources, and hence should be used in preference to building additional peaking generation. However, their high short-run marginal costs prevent them from doing the kind of speculative dispatch required by the current market design.

If demand resources were to attempt such speculative dispatches, they would run into two problems:

1. They would be trying to anticipate much rarer events – episodes of particularly high prices – and hence would get it wrong much more often.

2. The consequences of dispatching on the basis of an erroneously high price forecast are much more serious, possibly wiping out all potential profits for the year.

This is not a general shortcoming of energy-only market designs; rather, it arises from the combination of an energy-only design with a one-shot, real-time-only energy market.

It can be fixed by either:

- moving away from the energy-only design by introducing capacity elements, so that the precise outcomes of energy market dispatches become less important for resources with high short-run-marginal-costs; or

- moving away from the one-shot real-time-only design by introducing a day-ahead (or even hour-ahead) market, so that some degree of price certainty can be provided to all resources; or

- having an explicit mechanism for unit commitment.

[2] These extreme demand peaks generally do not appear unexpectedly at short notice. However, the corresponding price peaks are unpredictable.

We sense that the Commission is reluctant to give up on the energy-only design quite yet, and we know that mechanisms for unit commitment have been tried before in Victoria and proven troublesome. Hence we suggest that moving away from the one-shot design is the most practicable option.

The other timing issue that should be resolved is the discrepancy between 5 minute dispatch and 30 minute trading prices. This introduces unnecessary unhedgeable risks for both fast-start generators and fast-start demand resources.[3] Again, the consequences are much more severe, due to the higher short-run marginal costs, for demand resources than for generators. This is less serious than the issue affecting long lead-time resources, but it is quite easy to fix,[4] and there is no possible downside to doing so. It was argued when this issue was first raised a decade ago that the benefits of fixing the issue may not outweigh the one-off implementation costs of the necessary system changes; this will not be the case in future.

To reiterate: the demand-side bidding mechanism will bring significant benefits even without these reforms; if these improvements to dispatch and settlement processes can later be added, much greater benefits will be unlocked.

We are happy to provide whatever further information or analysis is needed to help the Commission refine the necessary reforms.

Yours sincerely,

Dr Paul Troughton
Manager of Regulatory Affairs
EnerNOC Pty Ltd

3 There are also philosophical objections to the current situation:
- Where a high dispatch price occurs only at the beginning of a trading interval, participants whose facilities are unable to respond in time to address the underlying issue are still rewarded by the high trading price if they turn up late and respond for the remainder of the trading interval, even though they're providing no benefit.
- Where an event causes a high dispatch price to occur towards the end of a trading interval, the effect on the trading price is non-causal: the high price takes effect up to 25 minutes before the event. An unpredictable retroactive price signal is not a useful price signal, as there is no way for participants to respond to it.
- It seems unreasonable for customers who are on "real-time pricing" arrangements only to discover the "real-time" price they are being charged for consumption in each trading interval in the 26th minute of the interval to which it applies.

4 It could be fixed, for example, by settling the market on the basis of 5 minute dispatch prices. Many of the larger sites already have 5 minute metering, or metering which can be reconfigured to produce 5 minute data. For others, unless they choose to upgrade their metering, a simple profiling approach can be used to convert their 15 minute or 30 minute data to 5 minute resolution. This will leave the market in balance.

Appendix A: Misconceptions regarding demand-side bidding

At the Public Forum held by the AEMC in Melbourne on 3 October 2012, the idea of demand-side bidding attracted vocal criticism from several parties. This criticism seems to have been based on a number of misconceptions, which we enumerate and correct below.

Misconception 1a: That demand-side bidding will distort the spot and/or hedge markets, such that retailers end up paying for it.

This issue was raised at the Public Forum by the ESAA, and has been mentioned by others. The idea is that retailers will either find themselves under-hedged, or have to buy more hedges, if their customers participate in demand-side bidding with a third party. It is wrong.

Under the proposed mechanism, during a dispatch of the customer's demand response in the wholesale market, it appears to the retailer as if the customer's load is unchanged: although their actual load will drop, providing the demand response, the customer will pay the retailer and the retailer will pay the spot market for the baseline load.

The baseline is the best estimate of what the load would have been if the demand response had not occurred. It represents what the retailer would have been expecting the customer to consume at this time.

The level of hedge cover required by the retailer is hence exactly what it would have been if no demand response took place, and hence exactly what the retailer should have arranged anyway. As such, the retailer is not directly affected by changes in their customers' demand during dispatches.[5]

This is a notable contrast from conventional network-focused demand response programmes, in which retailers experience unexpected load drops which can leave them over-hedged. Retailers already cope with this, and will have to do so on an increasing scale going forward.

Misconception 1b: That demand-side bidding will distort the spot and/or hedge markets, such that generators end up paying for it.

This issue was also raised at the Public Forum by the ESAA, and has also been mentioned by others.

The idea is that, because the dispatch of demand-side resources causes physical demand to fall, the output required from generators will fall. However, since the market treats the energy involved in the demand-side bidding as having been both generated and consumed, retailers will have to buy more energy than has physically been generated. The concern is that this may be covered by hedging

[5] They may be affected by changes in their customers' behaviour at other times – e.g. if a customer ramps down consumption in advance of a dispatch, or consumes more than usual after a dispatch to make up for lost production. However, these effects, which are common to all demand response, should be small, and not occur at times of extreme spot prices, so the impact on retailers is unlikely to be material.

arrangements with generators, who, because the level at which they have been dispatched has been reduced, may find themselves over-hedged, and hence having to make payments to counterparties at the spot price. This is also wrong.

The effect of a demand-side resource on the spot and hedge markets is exactly the same as that of a new-entrant generator. The new entrant only puts other generators at risk of being left over-hedged if those generators choose to offer their capacity into the market at a higher price point than the new entrant. They can avoid this risk by offering their capacity at a lower price point. Retailers might also choose to buy some of their hedge cover from the new entrant, if that is more cost-effective than the hedges offered by the other generators.

These effects are simply the normal response of the market to increased competition, not some "distortion" caused by demand-side bidding.

It should be noted that an excessive reliance on hedging by all parties is a response to the inefficiencies embedded in the market, not a solution to them. The current market design has resulted in grossly inelastic demand, creating a level of risk that necessitates an excessive reliance on hedging. Such excessive hedging actually exacerbates the market failure, as a party that is hedged against pricing volatility becomes indifferent to it. Customer indifference to the prevailing wholesale market then becomes a source of demand-side inelasticity.

Misconception 2: That for a customer to provide demand response in the wholesale market, it is necessary for them to be exposed to the spot price all the time.

This issue was raised at the Public Forum by Origin Energy. It is wrong.

Real-Time Pricing, as discussed in Chapter 6 of the Draft Report, is indeed one way in which customers can participate in the market. However, it is not the only way, and it is not one which has yet seen widespread adoption in any market.

Demand-side bidding provides the same price signal to customers, but selectively at times when they are able to respond. It hence has a risk/reward trade-off for customers similar to a Peak Time Rebate scheme, as discussed in the report prepared by the Brattle Group for the AEMC.[6]

Misconception 3: That demand-side bidding is a way for third parties to avoid the licensing obligations associated with becoming a retailer.

This issue was raised at the Public Forum by Origin Energy and Alinta Energy. The idea is that any party that wishes to engage in wholesale market DSP should become a retailer. It is wrong.

As is discussed extensively in Chapters 3 and 5 of the Draft Report, there are many activities relating to a customer's electricity consumption which are quite different in character from the core business of a retailer. There is no particular reason why all of these services should forcibly be bundled together such that the customer

6 Ahmad Faruqui & Neil Lessem, *Managing the Benefits and Costs of Dynamic Pricing in Australia*, The Brattle Group, 14 September 2012, p.7

has to choose a single package from a single party. There are, in fact considerable disadvantages to the current arrangement: in particular, conflicts of interest, and the fact that retail churn disrupts any other activities. Making these services separately contestable should bring benefits from competition, innovation, and the removal of conflicts. Allowing new types of participants facilitates increased *choice*, in line with the Power of Choice review's objectives.

Misconception 4: That all other demand-side bidding occurs in capacity markets, not energy markets.

This issue was raised at the Public Forum by Alinta Energy and the ESAA. It is wrong.

While it is clear that many demand response resources strongly prefer to participate on a capacity basis, many do participate in energy markets where they are allowed to do so.[7] In the US, Federal Energy Regulatory Commission Order 745,[8] in March 2011, established uniform principles for payment of such "economic demand response". Box 5.2 in the Draft Report describes the coexistence of both capacity-based and energy-based demand response in the PJM markets. The same occurs in other markets.

Misconception 5: That the potential introduction of demand-side bidding will act as a disincentive for customers to participate in network-driven critical peak pricing schemes.

This issue was raised at the Public Forum by the ESAA. The idea is that customers will be reluctant to carry out other forms of DSP, for fear that it will harm their baselines. It is wrong for two reasons.

First, only static baselines, such as the "maximum base load" mentioned Table A.7 in the Appendices to the Draft Report, or the "relevant demand" measure used in Western Australia, cause the effect of historical dispatches to persist for more than a few weeks. It seems more likely that dynamic baselines, which use only recent meter data, will be found to be suitable for the NEM.

Second, the purpose of a baseline is to determine the expected behaviour of the customer's load when it is not being dispatched for demand response. Hence intervals affected by other demand response dispatches are typically excluded from calculations.[9]

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7 The Wholesale Electricity Market rules in Western Australia do not yet make provision for demand-side bidding, only for demand-side participation in the Reserve Capacity Mechanism.

8 *Demand Response Compensation in Organized Wholesale Energy Markets*, available from http://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

9 These are described as "event days" in p.69 of the Draft Report. The same principle applies whether the other dispatches were for the same demand response programme, or another one. For example, in New York, when Con Edison dispatches demand resources for network purposes, it reports the times of these dispatches to NYISO so that they can be excluded from baseline calculations for NYISO's programmes.

Appendix B: Responses to issues raised in the Draft Report

Chapter 2: Facilitating consumer access to electricity consumption information

In relation to the discussion on page 27 about fees, which cites EnerNOC's Directions Paper submission, we would like to clarify that the significant fees we have been charged, as a third party, for access to customers' meter data have been charged by the meter data agents, not by retailers. The problem is that third-party agents, working to enable customer participation, face a monopoly: we cannot choose which meter data agent to deal with for access to a particular customer's data; rather, we have to deal with the agent chosen by the retailer.

1. What should be the minimum standard form and structure of energy and metering data supplied to consumers (or their agents)? Should these arrangements differentiate between consumer sectors (ie industrial/ commercial and residential)

While there is some benefit in providing summaries which are more easily interpreted by consumers, information is lost in this process. Any such summaries should always be in addition to providing the data in the most detailed form: all channels from the meters, with whatever time resolution they were originally recorded. Since we already have industry-standard formats – NEM12 and NEM13 – which preserve all details, and for which free analysis tools are available, there seems no obvious reason not to use them for this purpose. The same principles apply for all categories of customer.

2. When do you think it is appropriate for a retailer (or responsible party) to charge a fee for supplying energy and metering data to consumers or their agents?

We think it is appropriate for a fee to be charged only if value is being added – for example, if they are performing some analysis to assist the customer in managing their demand – or if delivery on physical media is requested.

Electronic delivery of raw data, if done efficiently, should be such a low-cost activity that it makes no sense to charge explicitly for it – it should be considered a very small part of the service provided by the meter data agent, covered by the fees it charges for meter reading.

Chapter 3: Engaging with consumers to provide DSP products and services

We welcome the recognition that, if it is determined that specific consumer protection arrangements are needed for DSP energy services, these should only apply to residential and small customers.

Chapter 5: Demand side participation in wholesale electricity and ancillary services markets

The discussion on pages 71-72 regarding a day-ahead market misses a crucial point: that the short-run marginal costs faced by demand resources can be one or two orders of magnitude higher than those faced by generators. This completely changes the effect of price uncertainty. A generator can afford to self-schedule in the face of price uncertainty, as the spot price, if it falls short of forecasts, is unlikely to be very far below their marginal costs. Conversely, a demand resource cannot take the same approach without facing significant unhedgeable risks; this will limit participation in demand-side bidding below efficient levels.

12a. Do stakeholders agree that the proposed demand response mechanism is likely to result in efficient consumption decisions by end-users? If not, are there any changes you recommend to the mechanism to facilitate this?

Yes. By broadening participation and providing strong price signals to participating customers, it should lead to much more efficient consumption decisions than at present. However, efficiency could be further improved by reforming those aspects of the market dispatch arrangements which favour generators over demand-side resources, as discussed in the cover letter.

12b. On balance, is a new sub-category of market generator required for consumers providing a demand that enables aggregation? What types of issues should be considered when developing the registration process?

Yes. A demand response aggregator's interactions with the wholesale market are much more like those of a Market Generator than those of a Market Customer, so this makes sense.

The proposed Market Small Generator Aggregator participant is the closest parallel; it may be that some commonality can be established between the two categories, reducing duplicated effort.

The key feature is that the registration obligations should apply to the aggregator, rather than to participating customers (unless a customer is participating directly).

Associating customer loads with an aggregated facility, or disassociating them, or transferring them between aggregations or aggregators, should be as simple as possible, without onerous manual steps, such as requiring the approval of retailers or DNSPs.[10]

13a. What factors should be taken into consideration when developing a baseline consumption method?

The key factors are accuracy, simplicity, and integrity.[11]

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[10] Neither retailers nor networks should be able to prohibit their customers from providing demand response to another party.

[11] See EnerNOC's 2011 white paper, *The Demand Response Baseline*, available from http://enernoc.com/images/whitepapers/pdfs/demandresponsebaseline.pdf for our detailed thoughts on these factors.

All baseline algorithms should be able to be calculated in real time in a totally deterministic fashion. This makes it straightforward to monitor performance, and to audit the calculation of baselines.

We believe it should be possible to agree on a default baseline algorithm that provides an appropriate balance between these criteria for the majority of customer loads. However, experience in other markets shows that no single algorithm can cope with all loads. The approach taken in PJM is to have one default algorithm, a selection of alternative algorithms,[12] and the ability for the market operator and curtailment service provider to agree site-specific approaches when necessary. The choice of baseline algorithm is agreed when the load first starts participating.

> *"All Economic registrations ... should go through the CBL certification process to ensure that the CBL used to predict the customer load and therefore determine the quantity of each hourly load reduction is reasonably accurate and non-biased. All registrations should use a CBL with a relative root mean square error ("RRMSE") no greater than 20% unless otherwise approved by PJM. Registrations with a RRMSE greater than 20% based on hourly load data provided in the registration process are considered variable load customers."*[13]

The philosophy behind PJM's approach is that, if a customer is able and willing to provide demand response to the market, some means should be found to measure it, rather than preventing them from participating. This can require additional up-front work when registering such loads, such as the installation of non-market sub-meters to distinguish the response of participating load from the rest of the site's load. Most of the burden of this work falls on the aggregator or the customer. However, the market operator, or some other regulatory body, must be in a position to vet the suitability of such arrangements.

13b. Have we identified the correct three key principles for developing a baseline consumption method (data refresh, accuracy, metering)?

Yes.

13c. Are there any substantial changes to metering and settlement arrangements required for this mechanism to be implemented? Can these issues be resolved through AEMO's consultation process and procedures or are broader amendments to the rules required?

The changes needed to metering and settlement arrangements are relatively minor, as the existing market mechanisms for parent-child metering on embedded networks provide most of the required functionality. However, it is possible that rule changes may be necessary to address some of the remaining requirements:

- **Communication of dispatches.** The Financially Responsible Market Participant for the demand response ("DR FRMP") must have some means, and an obligation, to inform AEMO about the start and end of

[12] PJM, *Manual 11: Energy & Ancillary Services Market Operations*, 1 October 2012, section 10.4.2 , available from http://www.pjm.com/documents/manuals.aspx

[13] *Ibid.*, section 10.2.5.

dispatches in real time. Either AEMO or the DR FRMP can notify other interested parties, if necessary. This information is needed for settlement calculations, and for verification of baseline calculations. Information about dispatches for purposes other than demand-side bidding (e.g. network support programmes) is also needed when calculating baselines, so these could be notified through the same channel, appropriately flagged.

- **Access to meter data.** The DR FRMP needs access to both current and historical data (including AEMO's settlement-grade data) from the customer's meter, so that they can calculate baselines and delivered quantities of demand response.

  National Electricity Rules clause 7.7(a)(1) appears to give the DR FRMP the right to access these data, but changes may be required to AEMO's systems to allow them to exercise this right. The current embedded network arrangements give the parent FRMP access to data from child meters, but do not give the child FRMP access to data from the parent meters.

- **Baseline and performance calculations.** Provision must be made for some party to calculate the baseline using the pre-agreed baseline algorithm for each load, and to use the result to derive the amount of energy provided by each demand response NMI in each interval. The DR FRMP is the logical party to perform this calculation. Clearly, this must be subject to an audit and enforcement regime; the AER is the logical party to have this responsibility. The resulting meter data streams for the DR NMIs should then be supplied to AEMO for settlement, and to the relevant retailers.

- **Loss factors.** The transmission and distribution loss factors to be applied to a customer's demand response require some consideration. As with generators, ideally the loss factors should represent the marginal effect of dispatches on system losses, averaged across all the dispatches. Annual average loss factors are not representative of the high demand periods at which demand response tends to be dispatched, when losses tend to be near their highest. However, calculating DR-specific loss factors for each participating site would be overly burdensome, so it makes sense for the site's normal loss factors, as applied to loads, to be used for demand response unless the customer elects to have a site-specific DR loss factor calculated at their expense.[14]

14a. Do you agree that similar arrangements for generation should apply to demand resources in terms of thresholds for registering as scheduled or non-scheduled basis?

Yes.

[14] In all cases, identical loss factor adjustments must be made to the baseline and to the metered energy; this is most straightforwardly ensured by calculating baselines and demand response performance for each NMI on non-loss-factor-adjusted data, then applying loss factor adjustments to the result. This may seem obvious, but this mistake was made in the initial version of the Western Australian market rules.

We agree with the statement on page 70: "An increase in the level of non-scheduled load is likely to impact AEMO's ability to accurately forecast demand, leading to inefficient dispatch volume and pricing." The dispatch inefficiencies caused by the volatility and unpredictability of both loads and prices are already serious; it is important to avoid further worsening. Hence strenuous efforts must be taken to ensure that participation on a scheduled basis is viable, and as many resources as practicable do so.

The 30 MW threshold above which scheduled participation becomes mandatory (with a few exceptions) should be applied not on a site-by-site basis, but on a region-by-region basis: thirty 1 MW resources in the same price region all being operated together at the same price threshold has the same impact on market prices, and a similar impact on power system stability, as a single 30 MW resource.

We suggest that this approach should be taken with generators (including small generator aggregators) as well as with demand resources. Transitional arrangements may be required for the handful of existing participants who have circumvented the 30 MW threshold through approaches similar to the 30x1 MW technique discussed above.

14b. What are the ways in which the regulatory arrangements can be adapted to facilitate the participation of scheduled and non-scheduled load in AEMO's central dispatch process? Are there any specific changes to reporting, telemetry and communication requirements?

Aggregation is important, as it increases reliability and predictability and reduces transaction, equipment, and compliance costs. Unless the customer chooses otherwise, dispatch offers should be made, and all requirements and obligations should apply, on an aggregated basis, rather than a site-by-site or NMI-by-NMI basis.

The area over which resources can be aggregated for these purposes requires some thought. If it is too small, then the aggregation benefits are lost, reducing participation and increasing costs. If it is too large, it risks impeding efficient dispatch, as the location of resources relative to constraints will not be correctly considered by the dispatch engine.

The current bid and offer aggregation guidelines in Rules clause 3.8.3 are not appropriate for this purpose: they only allow aggregation of generators and scheduled loads for energy market purposes at the site level, which barely counts as aggregation at all. For ancillary services purposes, however, they allow aggregation of loads[15] at the level of a NEM region.

Aggregation at the TNI level is initially appealing, in that it would avoid complexity with transmission loss factors, and allow demand resources to be dispatched to address any intra-regional transmission constraints. However, this is probably too small an area to give the right trade-off between aggregation benefits and dispatch flexibility. Aggregation at the NEM region level, as for ancillary services,

[15] … but not generators. This asymmetry seems to be an oversight, and should be corrected, perhaps as part of the changes introducing a new category of market participant for non-energy services. Provision of ancillary services from an aggregation of small generators seems perfectly feasible.

seems more suitable. It may be that AEMO could suggest a level of granularity between these two extremes which would capture the most significant transmission constraints while still allowing sufficient aggregation.

The current telemetry and communication requirements for scheduled resources were developed for large, centralised resources. They may well need to be relaxed to provide a sensible balance which meets the market operator's actual requirements without imposing excessive costs for large aggregations of small resources.

It will be necessary to develop suitable tests for judging conformance with dispatch targets. The existing tests and thresholds, currently used only for large generators and pump-storage schemes, are unlikely to be directly applicable to aggregations of demand resources. The equivalent threshold used in PJM is ±20%.[16] It may be appropriate to develop an approach analogous to the semi-scheduling used for intermittent generators, to reflect the inherent uncertainties in dispatching demand resources.

14c. Should both market and non-market loads above a certain size be required to provide information to AEMO regarding their controllable (and therefore interruptible) load blocks?

Yes.

14d. Should there be a trigger in the monitoring and reporting framework that requires consumers to provide greater detail regarding their demand resource to AEMO or affected DNSPs?

Providing "non-binding standing advice of expected demand response"[17] to AEMO is not an onerous administrative burden and should not cause any controversy, so long as it is provided on a confidential basis, only to be used to improve modelling of aggregate price-responsiveness and resource adequacy. It would make sense to require this right away, so as to improve predispatch forecasts, rather than waiting for a trigger.

It is not clear, however, that such information would be of much use to DNSPs, as it describes price-responsive load, rather than demand-responsive load. Its effect on local system peaks will be fully reflected in DNSPs' aggregate demand measurements.

15. How should AEMO's powers be expanded to improve demand forecasting? Should retailers and other market participants be obliged to provide information regarding DSP capabilities? Will non-obligatory requirements achieve the desired accuracy in reporting requirements?

Yes, all participants should be required to provide information to aid forecasting. To be effective and complete, this must be obligatory.

16 PJM, *op. cit.*, section 10.4.3.
17 Draft Report, p.70.

It must be recognised, however, that there is a limit to the level of accuracy that many participants can provide, as they are dependent on their customers' equipment and behaviour.

However, it should be straightforward for participants to give AEMO sufficient information to inform their modelling of likely behaviour. For example, they should disclose NMIs which participate in a retail or network DSP programme, along with the basic parameters of those programmes. Similarly, NMIs where the customer is exposed to the spot price should be disclosed. All of this will have to be on a confidential basis, with the information only being released in aggregate and through improved modelling.

If such data are provided by all participants on a reasonable efforts basis, the result should be markedly more useful than the current data set.

16. In what ways can AEMO improve its survey questions regarding DSP capabilities? How often should AEMO be required to update its expectations on DSP capabilities in the NEM?

Much of what the survey currently attempts to discover could be achieved through the mandatory reporting requirements discussed above.

If a large proportion of DSP adopts the proposed demand-side bidding mechanism, AEMO will not need to rely so greatly on surveys and disclosures, as they will have real data which will be much easier to model. Minimising barriers to scheduled participation will make yet richer data available to AEMO.

17. Would a pre-dispatch that includes active and price-responsive DSP improve decision making processes for C&I users and aggregators? If not, do you have any other suggestions for improving the ability for AEMO to accurately forecast demand?

Improving pre-dispatch forecasts, especially the 5-minute pre-dispatch forecasts, is vital. Currently, the forecasts, while reasonable most of the time, tend to be hugely misleading in exactly the circumstances in which DR is likely to be dispatched.

It should be noted that, even if it were possible (which it clearly is not) to produce pre-dispatch forecasts which perfectly incorporated the price-responsive behaviour of unscheduled resources, this would not prevent poor dispatches. This is because rebidding by scheduled resources causes a great deal of uncertainty about price outcomes.

The right way to fix this is through a two-stage market. Day -ahead markets are the most common form, but even an hour-ahead market, separating the gross economic dispatch from the adjustments needed for balancing, would solve this issue. This would both increase dispatch efficiency and reduce opportunities for gaming.

15. Do you agree that a new category of market participant should be established for the provision of non-energy services?

Yes.

16. What types of issues should be considered when developing the registration process, such as eligibility, obligations and liabilities?

The registration process should be as straightforward as possible. Each participant should only need to register once. Again, the existing Market Generator and proposed Market Small Generator Aggregator participants are the closest parallels. The lack of interaction with the energy market should considerably reduce the necessary obligations and liabilities.

Chapter 6: Efficient and flexible pricing options

There is an error on page 90, in which it is stated that "in New Zealand 30 per cent of consumer bills are transmission costs". The actual figure is around 7.4%.[18] AusGrid's statement, however, that transmission costs make up a large proportion of Orion's cost structure, is correct. This does perhaps highlight a relevant difference in the approach to charging for network services: why is it that a New Zealand DNSP considers transmission charges to be part of its cost structure, and hence takes action to minimise them, whereas in the NEM, DNSPs seem merely to pass TUOS charges through?

18. Do stakeholders agree with our approach for phasing in cost-reflective pricing? If not, how can the policy be improved to transition to cost-reflective pricing?

Yes, it seems broadly sensible. We would caution, however, that the term "cost reflective pricing" is being used to cover a wide variety of tariff arrangements, from strong, targeted measures such as critical peak pricing, through to rather gentle time-of use tariffs.

We must take care not to let this broad terminology confuse policymakers into expecting gentle tariff measures to produce the significant reductions in peak demand that have been seen from stronger measures.

The examples given by the Victorian government in the launch of their newly-rebranded "flexible pricing" initiative, and the time-of-use tariffs considered in the retail tariff model prepared for this review by Frontier Economics, are all towards the gentle and relatively ineffective end of the spectrum: more suited to ensuring that baseload generators remain fully loaded during the night than to reducing investment in peaking resources and network infrastructure.

19. Have we identified the main issues with transitioning to cost reflective pricing? If not, what other issues need to be considered?

Yes.

[18] Electricity Authority, *Factsheet 2 – A typical bill*, June 2012, available from http://www.ea.govt.nz/consumer/factsheets/

Chapter 7: Distribution networks and distributed generation

Unaddressed flaws in the regulatory model

As discussed in the cover letter, we welcome the clear analysis of the distortions caused by the current network regulatory regime, but are disappointed that the draft recommendations do not attempt to address several of the identified issues. In particular:

- **Different treatment of opex vs. capex.**[19] The issues causing NSPs to favour capex over opex are correctly identified. This is a real problem, and has been solved in the UK by harmonising the treatment of all expenditure as "totex". The counterexample given – that an NSP would prefer opex over capex if it were unable to raise funds for capex – is irrelevant: no NSP should be in that situation.

  Since the most efficient demand response projects tend to entail avoiding capex by increasing opex, any bias towards capex will lead to a bias against demand response.

- **Coupling of revenues to volumes** (except in Queensland).[20] The Draft Report identifies:

  — That the price cap mechanism used in most states can act as a disincentive for NSPs to pursue demand response or energy efficiency, because any reductions energy throughput will reduce the NSP's revenue.

  — That in theory, the price cap approach should provide a financial incentive for NSPs to set efficient tariffs, which the alternative revenue cap model would not. However, in practice, the price cap model does not provide an effective incentive.

  — That the price cap approach has resulted in some NSPs earning much more revenue than needed – it is not clear whether the AER believes this is due to random forecasting errors or deliberate rorts.

  — That a move towards time-of-use network tariffs will lead to NSPs' revenues becoming increasingly weather-dependent, possibly exacerbating the issue with forecasting errors noted by the AER.[21]

  Given this background, it seems perverse not to resolve the disincentive and over-recovery issues by moving to a revenue cap design – why favour a model with known flaws and theoretical (but unrealised) benefits, over one without such flaws?

  The decoupling of revenues from throughput is widely seen as a prerequisite for utilities to support demand response and energy efficiency programmes with enthusiasm.[22]

[19] Draft Report, pp.131-132.
[20] Draft Report, pp.127-130.
[21] It is worth noting that such revenue volatility is likely to increase private-sector NSPs' funding costs, as investors and lenders will consider their businesses to be more risky.
[22] Regulatory Assistance Project, *Revenue Regulation and Decoupling: A Guide to Theory and Application,* June

These issues should be fixed before they do more harm. Attempting to neutralise their effects on DSP through the design of an incentive scheme is a more complex approach which will result in higher administrative overheads both for NSPs and the AER. To fully neutralise the effects, NSPs will also have to be compensated for the additional administrative burden associated with the approval and compensation for each DSP project.

Design of a Reformed Demand Management Incentive Scheme ("RDMIS")

We welcome the recognition that the DMIS and DMEGCIS are not really incentive schemes. We would suggest that some other name be found for the real incentive scheme proposed in the Draft Report, to avoid confusion with these previous, discredited schemes. For now, we will call it the RDMIS.

The design of this scheme is crucial, as, if the wider regulatory distortions are not fixed (as seems to be the plan), NSPs will continue to do very little DSP outside of the incentive scheme. Hence any progress depends on the scheme.

The "efficiency benefit sharing scheme for capex allowance which is deferred as a result of DSP investment"[23] is a good starting point for the scheme, as it can provide a positive incentive that remains stable throughout the regulatory cycle. The stated design principles[24] make sense. We have a few additional observations:

- The value of the incentive should be proportional to the net benefits. This way, the NSP is incentivised to seek out *the* most cost-effective non-network solutions, rather than just *any* non-network solution that is more cost-effective than the network alternative. This should help correct the tendency of regulated utilities to favour the most glamorous, capex-heavy technologies.

- For demand response projects (unlike price-based approaches) the treatment of "lost consumer benefit" is straightforward, as this must be covered by the fees paid to participating customers – otherwise they would not participate.

- One of the advantages of DSP projects is that they can have a shorter lead time than a capital works programme – sometimes less than a year. One of the disadvantages is that it is difficult to pin down specific costs a long way ahead of time – customers are generally not willing or able to commit to participate in a scheme years ahead of seeing any benefits from it. Hence it is important that NSPs are able to propose new DSP projects, eligible for the RDMIS, at any time, regardless of the point in the regulatory cycle. Requiring 5 years' worth of DSP projects to be planned and then approved up-front as part of the regulatory determination would be unworkable.

2011, available from http://www.raponline.org/document/download/id/861 gives a great deal of background about the effect of revenue decoupling (and the lack thereof) on utility motivations. p.50 is particularly pertinent.

[23] Draft Report, pp.121-122.

[24] Draft Report, pp.123-124.

- Where a DSP project is intended to avoid or defer some specific planned capital works, the benefit is easy to identify and value. However, there is also merit in broader-based network peak reduction schemes, such as those currently being undertaken by the Queensland DNSPs. The rationale for these schemes is that reducing extreme peaks in demand will generally improve productivity and reduce the need for future capex. To value such programmes, deemed average values of peak reductions must be used.
- It is suggested that "the scheme should be developed through consultation between the AER and the network businesses". We would suggest that broader participation in this consultation, including consumer representatives and energy service companies, is essential.

Sticks as well as carrots

As discussed in the cover letter, a "moderately-sized carrot" approach is unlikely to bring about effective change in investment decision making for all NSPs, as the entire scheme could simply be ignored by those NSPs that are least well prepared to engage in effective DSP.

A "very large carrot" approach would succeed, but it would be unnecessarily expensive; a "carrot and stick" approach can achieve the same end without the need for the very large carrot.

Alternative approach: treating DSP programmes as assets

An alternative, and possibly simpler, approach would be to allow network businesses to treat cost-effective DSP programmes as assets, which would exist in their regulated asset base for as long as the programme is in operation. This provides a work-around for the distortion caused by differential treatment of capex and opex, targeted specifically at DSP programmes, since they are most strongly affected.

If this approach is taken, then the positive incentive to engage in a level of DSP closer to the optimum can be provided simply through allowing NSPs to earn a higher rate of return on such assets than on normal capital assets. The combined capex and opex wrapped up in the DSP asset cost much less than the alternative conventional infrastructure asset. Therefore the total cost borne by customers will be reduced, even if the allowed rate of return is set considerably higher than that for normal capex so as to provide a strong incentive to the NSP.

22. Would it be beneficial to include reference to the suggested mechanisms and provide more guidance and an overall objective in the Rules governing the demand management incentive scheme?

It is vital to get the schemes set up correctly in time for the next round of regulatory resets. While it would be preferable to give good guidance in the Rules, this is less important than getting them right and having them ready in time.

23. Should separate provisions for an innovation allowance be included into the rules? Given that the costs of the allowance would be borne by electricity consumers, is it more appropriate for such innovation to be funded through government programs?

The innovation allowance, if it continues, should be separate from the RDMIS. The innovation allowance has not typically been spent wisely, or on anything particularly innovative, and hence has given the DMIS/DMEGCIS a bad name.

24. Should the provisions for a demand management incentive scheme be included in the regulatory framework for transmission businesses?

Yes.

25. What amendments are required to the current distribution pricing principles as set out in clause 6.18.4 of the national electricity rules?

It should be accepted that the price cap approach does not provide sufficient incentives for DNSPs to set efficient prices, and so more detailed principles should be provided to overcome this. This will also facilitate a change to a revenue cap approach.

RIT-D

The Draft Report suggests that "DSP projects implemented by networks may also provide non-distribution benefits, **such as wholesale price savings**...", and goes on to suggest that these might be captured by the market benefits element of the RIT-D.[25]

The RIT-T is already meant to incorporate such market benefits. However, in practice, it does not:

> *"The RIT-T does not take into account changes in NEM prices as a category of market benefit, since this represents a transfer between producers and consumers, rather than an overall net benefit to the market."*[26]

Is there a deliberate difference in the treatment of market benefits between the RIT-T and proposed RIT-D?

Distributed generation incentives

The discussion on page 141 regarding distributed generation incentives rather misses the point.

An RDMIS will provide an appropriate incentive for NSPs to use DSP (possibly including distributed generation) to address network issues. However, this is an entirely separate issue from that tackled by the Ofgem framework: incentivising DNSPs to be helpful, rather than obstructive, when proponents seek to connect

[25] Draft Report, p.135.

[26] ElectraNET/AEMO, *Heywood Interconnector RIT-T Project Assessment Draft Report*, September 2012, p.25, available from http://www.electranet.com.au/assets/Uploads/HeywoodRIT-TPADR.pdf

generators to the network and export power via it. This has nothing to do with the deferral of network augmentations: most such generators are not intended to provide benefits to the DNSP; proponents want to install them for their own purposes.

The RDMIS discussed thus far does nothing to address this issue of generator connection, and there is no reason for it to do so. A separate scheme, along similar lines to the Ofgem approach, would work in the NEM.

DNSPs owning and operating generators

We are glad that the Commission "acknowledge[s] stakeholder concerns regarding the need for clear separation between the regulated and competitive sectors of the NEM."[27]

The supply, installation, ownership and operation of distributed generators for network support purposes should clearly be a competitive sector. There is no shortage of other parties willing to install and operate generators for network purposes if given the chance. There should be no need for DNSPs to own and operate generators themselves except to deal with emergencies and outages.

Although such specialists may well be more efficient than DNSPs at installing and operating generators, they are already at a disadvantage in selling those services to a DNSP, when compared to the DNSP's in-house team or a related party. The external specialist cannot be sure of equitable treatment in arranging the connection of a generator. Unfortunately, the generator connection process is so subjective that no amount of ring-fencing could plausibly prevent bias.

There is evidence that this is a real problem already; allowing a DNSP also to earn energy revenues from generators it owns (whether there is an attempt to ring-fence them or not) would only tilt the playing field for this supposedly competitive procurement further in favour the monopoly business and its related parties.

Such a tilt to the playing field would not only affect generator proponents, as it could lead to DNSPs favouring in-house or related party generator solutions over non-generator DSP solutions.

Chapter 8: Supply chain interactions

There is an error on page 149: "For most industrial and commercial consumers, the marginal costs of supplying and delivering electricity are partially reflected in their pricing structures." The data actually suggest that a handful of the very largest, most sophisticated customers are exposed to the spot price. As indicated by the submissions of the Energy Users Association of Australian and The Major Energy Users Inc on the Directions Paper, although many industrial and commercial customers are on some form of time-of-use tariff, these are typically far from being cost-reflective.

[27] Draft Report, p.144.