EnerNOC Pty Ltd
ABN 49 104 710 278
Level 1, 250 Queen Street
Melbourne VIC 3000

Tel: +61-3-8643-5900
www.enernoc.com.au
info@enernoc.com

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

4 May 2012

Dear Commissioners Pierce, Henderson, Spalding,

Response to Power of Choice Directions Paper (EPR0022)

EnerNOC Pty Ltd appreciates this opportunity to lodge a submission to this important market review. EnerNOC is an independent aggregator of demand response, currently managing over 8,000 MW of dispatchable demand response sourced from nearly 12,500 commercial and industrial sites across markets in the US, UK, Australia and New Zealand.

The Directions Paper published on 23 March 2012 contains insightful analysis of the Demand Side Participation ("DSP") issues facing the National Electricity Market ("NEM").

While there are many potential reforms which would help address some of these issues, we have focused this submission on one relatively simple reform that could greatly improve outcomes: the introduction of demand-side bidding.

As discussed herein, creating an opportunity for demand response ("DR") resources to participate directly in the NEM will bring great benefits by increasing competition in the wholesale market, and, even more relevant to the title of the review, give consumers more *choices* and greater opportunities to participate meaningfully in the NEM.

This current absence of DSP competition has led to the NEM employing inefficiently low levels of demand response, and hence to unnecessarily high costs.

This submission:

(a) Identifies the problems which we seek to solve through demand-side bidding,

(b) Outlines the demand-side bidding mechanism that can solve these problems, and then

(c) Describes qualitatively the benefits of introducing demand-side bidding.

The attached Appendix contains responses to many of the issues raised in the Directions Paper, where EnerNOC has both an opinion and some expertise.

Since this is an important reform requiring careful economic analysis, EnerNOC has also commissioned two economic consultancies to lodge separate submissions providing their perspectives. NERA Economic Consulting ("NERA") is submitting a report examining the issues with the current NEM design which are apparent from economic theory, and showing how demand-side bidding can address these. In addition, DNV KEMA ("KEMA") is submitting a review contrasting the levels of DSP

participation in the United States at the PJM Interconnection ("PJM"), a wholesale market whose design allows for effective DSP competition, with those at the Electric Reliability Council of Texas ("ERCOT"), which does not.

Problems

There is no competition to procure demand response

An electricity user can in principle provide DR for multiple purposes. Unfortunately, with the current NEM arrangements, each of these types of DR can only be procured by—and customers may only choose—one party:[1]

(a) In response to wholesale price peaks—this can only be procured by the consumer's retailer.

(b) Ancillary services, in response to system disturbances—these can also only be procured by the consumer's retailer.

(c) In response to distribution network peaks—this can only be procured by the consumer's local Distribution Network Service Provider ("DNSP").

(d) In response to transmission network peaks—this can only be only be procured by the consumer's local Transmission Network Service Provider ("TNSP").

The consumer has no ability to shop around for a better deal for their DR,[2] so there is no competitive pressure for these parties to provide good value to the consumer for their DR capabilities. This alone would lead to inefficient underuse of DR. However, since these parties are often reluctant buyers of DR, due to conflicts with their core businesses,[3] the effect is dramatic: in most cases, consumers receive no offers at all for any DR capabilities.

This contrasts with a competitive market environment, in which there would be multiple parties highly motivated to maximise their own profits by finding and procuring as much demand response capability as they can as efficiently as they can, so long as the resulting total cost is below the total value of the services to the markets in which they can be sold. This kind of competition spurs innovation, as each party tries to find the best methods to engage with particular types of consumers. Since consumers would be able to choose the most attractive offer, competitive tension between these parties would lead to consumers being highly rewarded for their DR capabilities.

---

1 We are ignoring the Reliability and Emergency Reserve Trader in this analysis, as it likely to be phased out without ever having been used, due to the restricted circumstances in which it is allowed to be used. One good thing that could be said for its design is that, it if had been used, it would have allowed parties other than a consumer's retailer to compete to procure their DR.

2 Although in principle the consumer could choose their retailer on the basis of the quality and attractiveness of their DR offer, this is very unlikely to happen in practice, as the value of the retail energy part of the deal with a retailer will usually greatly exceed the value of any DR part, leading to consumers justifiably ignoring retailers' attitudes to DR when choosing between them.

3 See our answers to questions 8, 9, 22, 36 & 37 for details.

Demand response is not allowed to compete with generation

Reducing demand affects the balance of supply and demand in exactly the same way as starting a peaking generator. On a longer timescale, assembling and contracting a portfolio of dispatchable demand-side resources can contribute to the security of supply in exactly the same way as building a new peaking generator.

> *Since demand response is actually—and not merely metaphorically—equivalent to supply response, economic efficiency requires that it be regarded and rewarded, equivalently, as a resource proffered to system operators, and be treated equivalently to generation in competitive power markets.*[4]
>
> The late Alfred E. Kahn
> Professor Emeritus of Political Economy at Cornell University
> and author of *The Economics of Regulation*

In the NEM, demand-side resources such as load curtailment are not treated equivalently to supply-side resources such as scheduled generation, despite being technically able to offer all the same services.

Specifically, there is no mechanism for a consumer who reduces their demand at a time of high wholesale prices to be paid the spot price for doing so. There is also no practical way for a consumer to set the spot price—this can only be done by scheduled resources.[5]

As a direct consequence of this asymmetry, there is little DR in the NEM. Instead of having vigorous competition between supply-side and demand-side resources to achieve an efficient, least-cost outcome, it is a one-sided market, in which demand is largely taken as an exogenous input, and prices are set only by the supply side. It has been aptly described as "the sound of one hand clapping".[6]

Solution

Principles

Both of these problems can be addressed by introducing demand-side bidding, in a similar manner to how it is implemented in other energy markets. There are several principles that must be satisfied:

(a) Consumers should have the choice to treat their DR capabilities as a resource that they can make available to the wholesale market in a comparable manner to a peaking generator.

(b) Consumers should be able to do this independently of their choice of retailer, either by participating directly, or by contracting with another party.

---

4 Prof. Alfred E. Kahn (2010), *Demand Response Compensation in Organized Wholesale Markets*, FERC Docket No RM10-17-000

5 We are ignoring the possibility of registering as a scheduled load. As noted on p.119 of the Directions Paper, no loads choose to do this in practice: it is not an attractive option because, despite its high costs and complexity, it does not result in any ability to *earn* spot price revenue.

6 Lance Hoch (2006), *The Sound of One Hand Clapping: The NEM without DSR*, Energy Users Demand Response Seminar, Sydney

(c) DR resources should be treated as part of the bid stack, in a comparable manner to a scheduled peaking generator.

(d) DR resources should be paid the spot price[7] for the DR they deliver to the wholesale market.

(e) If a consumer chooses to sell its DR into the wholesale market either directly or through a party other than its retailer, then the retailer should be unaffected by the DR actions of the consumer—i.e. the financial effect on their retailer should be the same as if the consumer was not taking any DR actions.

Baselines

For all forms of organised DR,[8] it is necessary to work out how much response has been delivered. This is done by estimating how much energy would have been consumed in a given interval if no reduction had taken place—i.e. if it had been business as usual; the amount of response delivered is the amount by which the actual energy consumption falls below this baseline.

Since many markets have DR as an integral part of their operation, there is extensive literature on the subject of baselines.[9] It is critical that care and attention be given to the development of accurate but adequately workable methodology for calculating baselines which is also robust against gaming. While this is a matter on which the AEMC would want to exercise its own due diligence, it is a solved problem for which there is ample experience and empirical data available from around the world.

Over the last year, all of the wholesale market operators in the US were required to develop baselines that would be sufficiently robust to permit demand response to offer into the wholesale markets on a regular basis. In each case, the market operator has advanced a baseline methodology that it asserted, based upon extensive study and expert analysis, would be adequate to the task.[10]

Market settlement

As was discussed at the AEMC's workshop on 27 April 2012, it is fortunately quite easy to introduce this style of settlement in the NEM, as most of the mechanisms required already exist.

Specifically, this arrangement is closely analogous to the treatment of embedded generators that are co-sited with consumer load and yet seek to participate in the wholesale market. In this case, the embedded network functionality within the

---

7 Specifically, the Regional Reference Price, adjusted for Distribution and Transmission Loss Factors.

8 By organised DR, we mean DR which involves either payments to providers or commitments to contracted levels of performance—i.e. everything except for pure dynamic pricing.

9 See EnerNOC's white paper, *The Demand Response Baseline*, available at http://enernoc.com/images/whitepapers/pdfs/demandresponsebaseline.pdf, for an overview of the baseline methods in common use.

10 See, for example two studies characterized by the Federal Energy Regulatory Commission ("FERC") as identifying "best practices for baseline calculations," KEMA *PJM Empirical Analysis of Demand Response Baseline Methods*, prepared for the PJM Markets Implementation Committee, April 20, 2011, available at http://pjm.com/~/media/committees-groups/committees/mic/20110510/20110510-item-09a-cbl-analysis-report.ashx and KEMA, *Analysis and Assessment of Baseline Accuracy*, prepared for ISO-NE, August 4, 2011 available at http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12737502

Market Settlement and Transfer Solution ("MSATS") is used to perform parent-child, or subtractive, metering, with the retailer's boundary meter becoming the parent meter and a new child meter, associated with a different Market Participant, being installed on the generator. The outcome of this approach is that:

(a) The generator is paid the spot price for all energy it generates.

(b) The retailer is unaffected by the actions of the generator: when the generator runs, it makes no difference to the amount of energy it buys from the spot market or bills the consumer for.[11]

The same approach can be used for DR settlement. The difference is that there is no physical child meter. Instead, the amount of DR delivered during a DR dispatch is derived from the difference between the baseline and the parent meter reading. At all other times, it is zero. The virtual child meter's data stream should reflect these quantities as if they were the output of an embedded generator.

The calculation of baselines and derivation of the virtual child meter data could in principle be carried out by any party that has access to the data from the parent meter along with the start and end times of DR dispatches. The task most naturally sits with the market operator, as they perform the rest of the settlement calculations.

Participation in central dispatch

The second principle above requires DR to be treated as a scheduled resource. This is desirable for two reasons:

(a) It gives greater certainty to the DR providers about their compensation, without them having to guess at the impacts of their actions on the resulting settlement price.

(b) It gives the market operator control: they know what is available and what to expect, rather than having to rely on forecasts accurately modelling consumers' responses to real-time prices.

The second reason is important: while the system can cope with an unscheduled activity while it is small in scale, as its penetration grows so does the difficulty of achieving a secure, efficient dispatch.

DR resources may be unable to be scheduled in exactly the same way as conventional scheduled generators, both due to their small scale and due to the performance characteristics of DR. Some work will be required to come up with a set of technical and operational requirements which strikes an efficient balance

[11] Retailer indifference to the consumer's actions is key to a successful mechanism—if a consumer chooses to perform DR using either generation or load curtailment without the involvement of their retailer, that retailer should neither be advantaged nor disadvantaged by the consumer's actions. In the US wholesale markets regulated by the FERC, this principle holds as well. However, FERC has ordered a cost allocation mechanism which socialises the costs of DR to buyers who benefit from the DR's participation. While EnerNOC has strongly supported the FERC approach to DR cost allocation, what is proposed here differs from the FERC-approved mechanism for reasons of ease of implementation. Treating DR in a similar manner to existing embedded generators which seek direct market access independently of their site's retailer has the great advantage of being easy to implement in the near term using existing functionality in all relevant participants' settlement systems. Although it does not give quite as good an allocation of the economic benefits as the FERC approach, it is far superior to the current situation in the NEM.

between providing adequate certainty for the market operator and avoiding prohibitive costs.

This issue has already been addressed for wind farms: since they are not able to comply with exactly the same technical requirements as other scheduled generators, the semi-scheduled classification was created for them. The rationale for this was that the benefits of including them in centralised dispatch outweigh the costs of treating them specially.

A sensible approach here may be to introduce DR participation on an unscheduled basis to start with, as that is relatively easy, while developing the necessary standards for them to participate in the centralised dispatch process. Issues to consider while developing these standards include aggregation, telemetry, conformance, and inflexibilities.

In the longer term, it may still make sense to give DR resources the choice of being scheduled or unscheduled, just as generators below a certain size threshold have this choice.

The same issues apply to the aggregation of small market generators, as is being considered in Rule Change ERC0141. It has been assumed in that consultation that all participating generators will be unscheduled market generators. However, it would be sensible to make provision for such aggregations of small generators to participate in central dispatch when they are large enough to be significant.

Benefits

The benefits of introducing demand-side bidding are clear: by allowing demand response to compete directly with generation, and introducing competition to stimulate efficient procurement of DR, the interaction between supply and demand will be improved, and lead to less peaky system load profiles.

Reducing the extreme peaks in the load profiles will significantly reduce the amount of investment needed in supply-side infrastructure. As discussed in the Draft Energy White Paper, if we continue without significant demand-side involvement, alarming levels of investment will be needed, largely to build infrastructure which will be poorly utilised.

The significant level of demand-side participation resulting from the introduction of demand-side bidding will also reduce the ability of generators to exercise or abuse market power.[12]

Demand-side bidding in the wholesale market will not directly help in procuring DR to relieve distribution and transmission network issues: it is difficult to introduce competition here other than by encouraging NSPs to be efficient. However, it will provide significant indirect benefits:

(a) The large-scale use of demand response in the wholesale market will improve the load profiles seen by transmission and distribution networks, with no

[12] See, for example, Stephen J. Rassenti, Vernon L. Smith & Bart J. Wilson (2003), *Controlling market power and price spikes in electricity networks: Demand-side bidding*, PNAS vol. 100 no.5 2998-3003, available from http://www.pnas.org/cgi/doi/10.1073/pnas.0437942100

action required by NSPs beyond incorporating this activity into their demand forecasts.

(b) If there is a broad base of consumers able to provide DR for wholesale market purposes, it becomes significantly easier and hence cheaper to procure their services for a programme initiated by an NSP. Without the wholesale market opportunity, any network support programme needs to start from scratch, and justify all the costs of recruiting, training, and equipping consumers on the basis of the benefits from that programme only.

Competition for procurement of ancillary services from consumers is a similar but simpler issue, discussed in our response to Chapter 8 of the Directions Paper, in the Appendix.

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

Yours sincerely,

Dr Paul Troughton
Manager of Regulatory Affairs
EnerNOC Pty Ltd

Appendix: Responses to issues raised in the Directions Paper

Chapter 1: Introduction and background

We welcome the recognition that "the wholesale component of electricity prices is responsible for the largest proportion of the projected increase" in retail prices,[13] as recent history may have led to too much attention being paid to the contribution of distribution networks.

Focusing on the top 1% of peaks, i.e. 88 hours, in which 4.8 GW of additional demand appears,[14] is a sensible way of quantifying the opportunity for benefits from increased DR leading to reduced supply-side investments.

This also shows the scale of the increase in DR participation required to deliver these benefits: 4.8 GW is around 14% of the system peak demand, whereas the estimates provided to the AEMC by Futura show that current levels of DR, excluding legacy load control programmes, address less than 1% of the system peak. Based on EnerNOC's experience elsewhere, we would expect commercial and industrial DR to be able to address around 10% of the system peak.

Evidence on drivers of peak demand

Chapter 1 discusses the drivers of peak demand and asks for evidence of factors which drive peak demand. We do not have any evidence to provide. However, we would like to emphasise that those sectors and activities which contribute most to peak demand are not necessarily those which can provide DR to reduce peak demand most efficiently.

For example, in many areas, peak demand appears largely to be driven by residential air conditioning. However, these great peaks in demand occur partly because residential consumers want to use their air conditioning when it is hot, i.e. they place a high value on the use of energy at this time.

Hence it would take a very strong price signal (whether a charge for energy or an offer to buy DR) to bring about much reduction in consumption from these users during critical peaks. Other sectors, particularly commercial and industrial consumers, may not place so high a value on some of their energy consumption at these times, so it is more efficient to seek DR from them, even though they may have a relatively flat load profile.

Because residential consumers, with their preference for air conditioned comfort, have particularly peaky loads, it could follow that there may be an excessive focus on attempting to discipline their behaviour. Such focus is not likely to be very efficient or successful. A better approach would be to introduce demand-side bidding so as to allow other classes of consumers which do not place so high a value on consumption on very hot days to address the resulting system peaks through a competitive wholesale market.

[13] Directions Paper p.20

[14] Based on AEMO "total demand" figures for 2011.

Chapter 4: Consumer engagement and participation

1. What should be the arrangements for consumers (or third parties acting on their behalf) to access their energy data?

Consumers should have the right to timely access to their data in a convenient form, and they should be able to delegate this right to third parties, subject to the expectation that such third parties would preserve the confidentiality of that data, according to the consumer's wishes.

2. Do you consider that there could be a role for an information service provider in the market as a mechanism to provide consumption data to consumers?

Yes. Although a similar outcome could be achieved by placing obligations on meter data agents, or by allowing AEMO to provide access to the data, having dedicated information service provider may be an easier way to achieve the necessary outcome.

At the moment, there is a problem that particularly affects third-party aggregators. Meter data provision is a contestable service. However, it is the retailer that chooses which meter data agent to use. A third party seeking access to this data has to deal with that meter data agent, who has a monopoly on access to that consumer's data. This leads to some extreme, non-competitive pricing for the service of forwarding the data, even though it is obvious that the actual cost of providing this service is so low that any cost-reflective charges for the service would be dominated by the cost of billing for the service.

A separate issue is that, at present, when a consumer churns between retailers, it causes all arrangements for meter data forwarding to be terminated, and they have to be renegotiated from scratch. This is wasteful and disruptive. Having a separate party, other than the retailer, responsible for verifying the consumer's consent would overcome this problem. An alternative would be for the onus to be on the third-party access seeker to obtain "verifiable consent" from the consumer, and be subject to audit on this matter; this is the approach taken in Western Australia.

3. Should amendments be made to the current NER clause 7.7(a) to facilitate consumer access to consumption information? If so, how?

There are two possibilities here:

(a) Extend access provided under clause 7.7(a)(1) from "Registered Participants with a financial interest in the … energy measured by that metering installation" such that it covers third parties facilitating demand response that is measured by the metering installation. For market DR, such as the proposed demand-side bidding mechanism, this may not require a change. For DR that is carried out for non-market purposes (e.g. for network support), explicit provision would be required.

(b) Extend the customer's powers under clause 7.7(a)(7) such that it is explicit that they can grant access to third parties.

Chapter 5: Efficient operation of price signals

8. Do retailers have the right incentives to pass through appropriate wholesale costs and network charges to consumers?

In aggregate, in the long term, yes: they want to make sure that their charges reflect their costs, plus a margin. However, they do not have an incentive to ensure that time-dependent price signals are preserved in this process. In fact, they have incentives to do precisely the opposite.

Retailers are in the business of risk management. The more they can manage risks for their customers, the more value they are adding, so the more margin they can make.

Consumers generally, and quite rationally, prefer to minimise the risks and complexity to which they are exposed. Having a simple one- or two-part tariff achieves this. Retailers are happy to satisfy this demand.

In addition, many retailers own generation assets, the value of which would be diminished were customers to choose to use less electricity during extreme peaks.

Thus, retailers appear to have incentives *not* to pass through wholesale costs.

9. Do retailers have an incentive to minimise the costs of their customers' consumption?

Not a strong one. In some cases, none at all.

Retailers generally hedge their exposure, such that they are not exposed to high spot prices: the hedge counterparty reimburses the retailer for the amount by which the spot price exceeds the strike price.

If retailers can reduce their customers' consumption marginally during a time of high spot prices, then they can keep the corresponding payments from the hedge provider. This is profit. However, this only works on the margin: if their actions cause the spot price to fall, which it can do dramatically due to the steepness of the top end of the supply curve, then:

(a) The profit disappears.

(b) Their competitors, who may not be so well hedged, get a "free riding" benefit.

(c) As discussed above, the retailer makes its margin from managing risks for its customers, protecting them from the dangers of the spot market. The more volatile the market, the more valuable this service is, so the greater the risk premium they can charge. Effective demand response action that reduces spot price volatility reduces the value of this service and hence the longer term profitability of the retail business.

(d) If the retailer owns generation assets, any reduction in the spot price, and in the volatility of the spot price, reduces the profitability and hence the value of those assets.

Hence although some retailers are incentivised to minimise their customers' consumption costs, the optimal strategy for them is to have only a little DR: enough to gain from arbitrage, but not enough to reduce the spot price.

10. Would a tariff with a fixed, variable and network LRMC element as described in section 5.8 closely reflect the costs of supplying electricity?

Not closely, unless the variable part was the spot price.

11. What are the restrictions on retailers offering such a tariff?

Assuming that retailers were interested and motivated to offer dynamic pricing, they would need interval metering. However, more importantly, they would need customers who actually wanted such a tariff.

Consumer preferences seem strong: all but the most sophisticated consumers tend to prefer simpler and less risky tariffs, even if this means that they're paying a premium. Indeed, it is that premium which underlies much of the retailers' business model.

12. Can efficient levels of DSP be achieved without cost-reflective prices? What considerations are needed to achieve this?

Yes. Consumers do not need to be exposed to cost-reflective prices all the time, as the subset of consumers who are able and willing to manage the associated risks is rather small.

In the wholesale market, giving consumers the *choice* to expose themselves to spot market price signals when they are able to respond is a more powerful approach that can elicit greater levels of participation, while providing exactly equivalent economic incentives to cost-reflective pricing.

In addition, such an approach allows each customer to tailor its degree of participation to its particular situation at any given time. It would be difficult, if not impossible, for any retailer's tariff or contract offering to provide such flexibility.

A 2004 study conducted by Lawrence Berkeley National Laboratory also concluded that demand response programs may be a more cost-effective way to achieve the same benefits that might otherwise be sought through cost-reflective pricing: (they refer to this as Real Time Pricing, "RTP")

The costs and benefits of obtaining incremental amounts of price-responsive load from RTP must be weighed against those of other types of demand response mechanisms. If the baseline level of interest in RTP is limited to a small number of large industrial customers, utilities may have to devote significant resources to entice a substantial number of additional customers to enroll. Policymakers should weigh the costs of these further inducements and the incremental benefits against those of implementing alternative price response mechanisms. Given the diversity and heterogeneity of retail customers, a portfolio of RTP and other demand response programs, including some fast-response options and others that build long-run price response behaviors, may be more likely to achieve meaningful levels of price-responsive load than focusing exclusively on RTP.[15]

13. What other market conditions need to change to enable cost-reflective prices? Will the benefits from improving the cost reflectivity of price signals outweigh the costs of the actions to improve them?

It is debatable whether the benefits would outweigh the costs.

Exposing residential consumers to cost-reflective pricing is expensive. At a minimum, cost-reflective pricing requires an interval metering roll-out. To achieve meaningful levels of participation, in-home controls would also be needed. Including in such a roll-out consumers who are unwilling or unable to respond leads to all of the costs, but no benefit.

Finally, to achieve any meaningful benefits in the market, a significant number of consumers would have to participate. In order to bring forth this benefit, some advocate for forcing consumer exposure to cost-reflective pricing, or for instituting an opt-out policy, such that consumers are exposed by default. Both of these approaches usually become controversial in actual practice.

Experience with cost-reflective pricing, especially pricing that reflects real-time wholesale prices, is mixed, however in the largest and most recent study of which we are aware, for Consolidated Edison in the US, the determination was that there was minimal demand elasticity and that expanding Mandatory Hourly Pricing from 500 kW and up customers down to 300 kW was not warranted[16].

Chapter 6: Technology and system capability

15. Are there any practical additional mechanisms that could help alleviate the barriers to consumer investing in DSP technology?

Yes: vibrant competition to procure DR from consumers.

This will provide choice to consumers, spur innovation by parties seeking to procure DR, and provide competitive pressure to ensure that consumers receive a high proportion of the value of their DR. It is this value that will drive them to choose to

---

15 LBNL, *A Survey of Utility Experience with Real Time Pricing*, December, 2004, p. ES-9, available at http://eetd.lbl.gov/ea/EMP/reports/54238.pdf

16 KEMA, *Mandatory Hourly Pricing Program Evaluation Report*, May 1, 2012. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1BB38D64-2382-4AF4-8A1D-46622C0A5585}

participate.

16. What should be the role of intermediaries such as ESCOs in addressing the barriers to efficient consumer investment and what factors could be impeding the development of these parties?

They can find consumers who have a latent ability to provide DR, inform them of the possibilities, and persuade them to participate. They can fund the technology, so that consumers do not have to make an investment decision. They can manage the risks of the consumer's participation, so that it becomes an easier choice for the consumer to participate. They can help the consumer to improve their performance and reliability, and hence increase the value of their participation. They can extract the maximum value for them from their DR capabilities, by seeking out all efficient uses of those capabilities.

The development of this sector is impeded by there not being anywhere to sell the resulting DR services: there is no mechanism for direct access the wholesale market, and retailers are generally conflicted or just not interested. It is possible to sell DR services to NSPs. However, the NSPs' business cases rarely stack up when they have to bear the full cost of recruiting DR. Being able to combine their projects with wholesale market access would change this.

17. What amendments to the metering arrangements in the NEM are required to facilitate commercial investment in metering technology which supports time sensitive tariffs?

The introduction of demand-side bidding, as proposed in this submission, combined with the ability of third-party aggregators will allow such aggregators to install their own real-time metering at no cost to consumers, provide the resulting data to their customers at no additional cost to them or other consumers, and allow such customers to provide the same or greater benefits as would accrue under a real-time pricing regime.

18. Are the current arrangements sufficient to facilitate a consumer's decision to install their own meter as a revenue meter? If not, what changes to the current arrangements are required?

As discussed above, permitting customers to *choose* to offer their demand reductions into the wholesale energy market through third-party aggregators will lead to such aggregators installing their own meters, providing the functional equivalent of a new revenue meter. In EnerNOC's case, such meters are provided at no charge to the customer.

19. Are any amendments to the arrangements required to encourage either the network businesses or retailers to invest in metering capability in order to support DSP options?

Network businesses and retailers do not need to invest in metering capability in order for consumers to have the opportunity to participate in DR.

20. Are there aspects to the arrangements regarding the integration of DSP technologies into energy networks that require further consideration under this review?

Open standards are important.

It is also important to avoid rent seeking by parties who find themselves a monopoly supplier of particular service to a particular party.

For example, many meters are able to provide a real-time indication of current consumption levels. The low-tech way of doing this is through pulse outputs. Some models of meter have such outputs as standard. Hence the marginal cost of supplying pulse data is nearly zero: they just have to be enabled, which can be done remotely. Others need to have an expansion card fitted, which costs maybe $100, plus a truck roll. In either case, the ongoing cost is $0/year.

Since the meter provider is generally chosen by the retailer or the DNSP, not by the consumer, there is no competitive pressure for the meter provider to charge in a cost reflective manner for any additional services provided to the consumer or to a third party.

In the case of pulse outputs, the upper bound on what they can charge is the cost to the consumer of replacing the meter with one from another meter provider that might provide cheaper pulse outputs, or installing a non-market check meter alongside the existing meter, and using its pulse outputs. The profit maximising approach for meter providers is to charge something approaching this upper bound. Accordingly, there are meter providers that charge hundreds of dollars for enabling pulse output, and require this fee to be paid *every year* on an ongoing basis, even though they incur only a minimal up-front cost to provide the service with no ongoing cost.

It is likely that similar issues will arise with access to real-time data from smart meters — either via a local connection in the premises, or remotely over a network. If the choice of meter provider were truly contestable — such that consumers were the meter provider's customers, then competitive pressure might act against this. However, this would require consumers to be fully informed about the significance of the costs for these services. In reality, many consumers will not know they may need these services when they make decisions about which meter provider to use, or whether to take the default option of leaving it up to the retailer or DNSP to choose.

Chapter 7: Supply chain interactions

21. Can you provide a practical example of a DSP option which could deliver a net benefit to the market and also to the various parts of a supply chain. What are the reasons for such opportunities not being captured today?

No, we cannot think of any DSP option that would benefit *all* parts of the supply chain.

Since effective DR provides direct competition to peaking generation, peaking

generators do not benefit from its introduction. Similarly, effective DR allows customers to physically hedge some of the market variability, and is thus in direct competition with the hedging services provided by retailers.

It is therefore important that such parties are prevented from impeding DR initiatives which increase overall efficiency.

22a. How do the current market arrangements promote co-ordination across the supply chain to promote efficient DSP?

Not very well.

Retailers have monopsony power over the use of their customers' DR in the wholesale market. NSPs have monopsony power over the use of DR to address network issues. There is no particular reason for them to cooperate.

Networks, as regulated monopolies, are not allowed to engage in energy market activities. This prohibition is appropriate. It may be worthwhile strengthening it, to prevent them from engaging in such activities through related entities.

Retailers are in principle able to play a coordinating role, but they mostly choose not to do so. Apart from the multiple issues that make many retailers reluctant to encourage DR, as enumerated in the answer to question 9, there are also some general problems:

(a) *Skills and capabilities.* Eliciting DR from consumers requires a very different skill set from selling them retail energy contracts. It requires a detailed understanding of their industry, technical knowledge about their processes and control systems, the ability to negotiate a suitable commercial arrangement (typically very different from a retail energy deal), and the operational capabilities to dispatch them and work with them to optimise their performance. Engaging with networks to provide DR requires expertise and the willingness to take on and manage commercial and technical performance risks.

    Since this is not a core business for retailers, they tend to view such activities as a cost, not something to develop.

(b) *Retail churn.* The high level of retail churn limits the ability and willingness of a retailer to procure DR from its customers. There are significant up-front costs to bringing a new consumer into a DR programme: both for the supply and installation of the necessary equipment, and for the labour cost of engaging with the customer to persuade them to participate and to work out with them how they can best do so. These costs have to be written off when the customer churns away; this makes it expensive and risky for retailers to invest in such activities.

Very large and sophisticated consumers can deal with these issues for themselves. For others, third parties are in the best position to work across the supply chain to make the best overall use of a consumer's potential DR.

22b. What potential improvements should be considered?

Unbundle DR from retail energy supply, so that third parties can compete to procure it. This will allow the development of a thriving, competitive market in procuring DR from consumers and using it to compete with peaking generation. The demand-side bidding mechanism proposed above will achieve this unbundling.

See our responses to questions 36 and 37 for issues specific to NSPs.

If NSPs are receptive to DR as an alternative to capital expenditure on network infrastructure, then the presence of a vibrant DR sector based around the wholesale market will make it much easier to procure DR for network purposes. In the absence of a wholesale market opportunity, it is slow, difficult, and expensive to procure DR for network programmes, as the whole programme must start from scratch, and justify all the investment required, on the basis of the value of the short-term network project alone.

This tends to mean that the only network programmes which appear efficient are those which can be satisfied by the actions of only a handful of large consumers. Anything requiring the coordinated action of a large number of small consumers does not stack up.

23. Do you consider that there is inconsistency between how the wholesale and market sectors value DSP impacts? If so, is this a material problem to be addressed?

Where DR can be used for multiple purposes—for example for network and for wholesale purposes—there is no requirement for it to be valued consistently for those different purposes.

If a demand-side resource is able to serve several purposes independently, there is no conflict: it should be paid for each service it provides, according to the value of that service. If there is a conflict between some of the purposes, for example between ancillary services and wholesale energy, such that the same resource cannot provide both services at once, then the consumer can choose the activity with highest value, or allow a third party to manage this choice on their behalf.

24. Can market mechanisms be improved to facilitate supply chain interactions for efficient DSP? If so, what options should be considered by this review and what considerations should be taken into account?

Yes. Unbundling, through the introduction of demand-side bidding, as described above.

25. Would fully cost-reflective price signals enable the supply chain to act in a co-ordinated manner towards efficient DSP opportunities or would additional amendments be needed?

This is a rather theoretical question, as fully cost-reflective pricing seems an unachievable goal. However, the answer is no, not entirely. Behavioural issues limit the benefits that can be achieved purely through cost-reflective pricing.

Consumers are (mostly) not the simple profit maximisers that economists like to

model. They can have rather more complex motivations, such as risk aversion, that will lead them to be prepared to pay a premium to avoid the possibility of downside risk.

Relying purely on cost-reflective prices would preclude participation by such consumers, even if they were often able to respond. It would also entrench the role of retailers as gatekeepers for DR, and largely preclude the participation of third parties, even though they are best placed to provide coordination across the supply chain.

27. What are your views on possible approaches to achieving co-ordination across the market participants in the supply chain?

The best way to achieve coordination is to allow third parties to compete to play this role.

No other class of market participant can achieve coordination across all participants in the value chain. This is because effective DR is contrary to the interests of some (generators and retailers/gentailers, whose assets or hedging services compete with DR) and unhelpful to the interest of others (NSPs, who earn no return on the DR that defers investments that would otherwise earn a return).

28. What should be the approach to quantify the value of DSP options?

In principle, the price of a corresponding financial derivative should indicate the value of an option over DR for wholesale purposes. This is difficult in practice, because the exchange-traded derivatives for which prices are published cover only a few years. Efficient DR activities are planned and valued over longer timescales. Although some derivatives are sold for longer periods, these transactions do not occur in public, and the prices are not published. Hence we have to fall back on the estimates based on the cost of constructing a comparable capacity of generation. This problem could readily be addressed in a capacity market framework.

When DR is being used to address local network issues, it is somewhat harder. The lumpiness of network investment requirements leads to DR having a low value to the network in most areas most of the time, but occasionally having an acutely high value in a specific area where upgrade works can be deferred or avoided. However, even this acutely high value tends to be rather fuzzy, as the timing of the proposed upgrade works, and the amount of DR required to safely allow their deferral, depends on rather uncertain forecasts. This makes it very difficult for NSPs to procure DR: programmes tend to arise at short notice, against a background of great uncertainty. There may, therefore, be some merit in using a somewhat spatially and/or temporally smoothed value of DR to make these programmes more manageable. Compared to perfectly calculated values, this approach may lead to somewhat inefficient over-procurement in some areas/times and under-procurement in others. However the practical benefits may lead to a more efficient overall result than the current approach, in which there is gross under-procurement almost everywhere.

Working out the quantity of DR that has been delivered depends on baselines. The baseline shows what would have been consumed if DR had not been dispatched; the

amount of DR delivered is the amount by which the energy consumption is reduced below this baseline. As discussed in our main submission, robust baseline methodologies are available.

29. Should standardised, common methods to forecast the impacts of DSP be developed? Is there a need for common approaches between network and operational planning?

This is an issue specific to dynamic pricing. With contracted DR, forecasting its impact is easy.

30. If the required co-ordination across the supply chain cannot be achieved, should a market participant be assigned with the responsibility to procure DSP options? If so, what issues need to be considered in the design of such an approach?

We believe a lot of the required coordination can be achieved by allowing third parties access to the wholesale market, and encouraging NSPs to choose the most efficient solutions when considering and procuring DR.

We believe that setting up DNSPs as "single actors" is a very bad idea. Rewarding monopoly businesses, which already have serious conflicts of interest leading to costly behaviour, with even more monopsonistic power than they already wield does not seem like an approach which will lead to an efficient outcome.

We would note, however, that there is some merit in having the market operator procure contracted DR. This is because they are uniquely positioned to integrate DR with their reserves management process. The ultimate realisation of this is a capacity market. It is comparatively easy to have an efficient level of DR in a capacity market. However, even while retaining a mainly energy-only market design, it can make sense for the market operator procure some resources on a capacity basis, as a way to achieve improved reliability outcomes without the need to raise the market price cap or alter other distortions such as the cumulative price threshold.

Chapter 8: Wholesale and ancillary services markets

31. Should there be additional obligations on market participants to provide information to AEMO regarding DSP capability?

Yes.

There is little long-term consumer benefit from DR unless its effects are reflected in the load forecasts, allowing capital expenditures to be reduced. Our proposal for demand-side bidding would lead to customers or aggregators providing AEMO with data comparable to that provided by each scheduled generator.

32. Are there issues relating to the costs and processes for becoming a registered participant in the NEM that require to be considered further in this review? If so, why?

Becoming a participant is not the problem. The problem is that, to use a consumer's

DR in the wholesale market, you currently have to be the one-and-only Financially Responsible Market Participant for that consumer's load. i.e. Either:

(a) The customer registers as a Market Customer themselves, which means that they are fully exposed to spot prices (unless they also set themselves up to trade in derivatives), must put up prudentials, and must settle weekly with the market. This is a very high hurdle, which almost no consumers can overcome.

or

(b) A "third party" becomes involved. However, this third party would have to become the consumer's retailer. So they become susceptible to all the issues that retailers have. So there isn't really an option (b).

The way to fix this is to allow a consumer's DR to participate in the wholesale market independently of their normal retail arrangements. The proposed demand-side bidding mechanism achieves this.

33. What issues should be considered regarding the role of aggregators in the NEM? Should there be a new category of market participant for aggregators?

Yes.

This is a good idea, and not particularly hard to do. It does require a new category of market participant. Experience from around the world demonstrates that where aggregators are allowed to offer demand response, participation is substantially improved. The US FERC implemented a major rulemaking around just this issue and determined that, except where retail regulators determine that it is inconsistent with state or local policy to do so, wholesale market operators *must* allow aggregators of retail customers ("ARCs") to offer demand response into all of their markets.

> *We find that allowing an ARC to act as an intermediary for many small retail loads that cannot individually participate in the organized market would reduce a barrier to demand response. Aggregating small retail customers into larger pools of resources expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability. We also agree with commenters that this proposal could encourage development of demand response. programs and thereby provide retail customers more opportunities available through larger markets. Additionally, as some commenters note, experiences with existing aggregation programs in PJM, NYISO, and ISO New England have shown that these programs have increased demand responsiveness in these regions.*[17]

The large majority of such regulators have determined that permitting ARC representation is in consumers' best interests. Those that have not have done so because they liken it to retail competition, which they have also banned.

[17] FERC, Order 719, *Wholesale Competition in Regions with Organized Wholesale Markets*, 125 FERC ¶ 61,071 at 83, available here http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=11833254

34. How effective are current financial contracts markets at providing a hedge against price risk for DSP options?

Totally ineffective.

Quite apart from the Financial Services Licensing issues which prevent most consumers from dealing with derivatives, the financial contracts that are traded do not provide anything similar to a day-ahead market: they span whole calendar quarters, rather than the shorter intervals over which a day-ahead market would usefully give certainty.

We would recommend reconsidering the potential for a day-ahead market. If this requires a separate review, then such a review should be initiated.

35. Given the discussion regarding the appropriate payment to DSP resources in the NEM, are there any other issues that should be considered by the Commission in regard to this matter? Are there any potential improvements to existing processes and other means to better facilitate DSP into the wholesale market that require consideration?

A disappointing aspect of this review is that, despite the very broad terms of reference, any major changes to the market design were quickly decided to be out of scope, without giving them any analysis.

This is a missed opportunity: while this review has brought to light some minor reforms—such as the introduction of demand-side bidding—which can bring about significant improvements, it is likely that larger reforms, with the potential for still greater benefits, have been overlooked.

What about ancillary services?

As discussed in the AEMC's workshop on aggregated ancillary services on 27 April 2012, a relatively straightforward rule change, with almost no implementation costs, is all that is required to allow consumers themselves, or third parties, to offer ancillary services into the market, independent of retailers.

Experience in New Zealand has shown that retailers do not do this themselves. We think this is partly because of skills issues, but mostly due to retail churn: ancillary services are a relatively low value service, such that it can take many years to recover the initial investment required to bring a site into the market.

Rationalising the technical requirements can help here: at the moment, the technical requirements are based around the assumption that each site is bespoke, and provides many megawatts of ancillary services capacity. Hence specifications which necessitate expensive equipment can be tolerated.

For large-scale ancillary service provision by aggregations of much smaller facilities to become feasible, a simpler, standardised approach is needed. For example, rather than requiring high resolution frequency data to be recorded for each event, some reliance can be placed on type testing before a roll-out of cheaper, simpler devices.

However, we would caution that the prices of ancillary services in most of the NEM are sufficiently low that this rule change by itself is unlikely to elicit much activity by

consumers or third parties. Ancillary services are more likely to be taken up as an add-on to an energy market DR programme.

What about a standing reserve?

On p.133 of the Directions Paper, the Reliability and Emergency Reserve Trader mechanism is described as a "standing reserve". It is not a standing reserve, as it is not a long-term programme. As was correctly identified on p.120, the short-term nature of RERT, if it were ever to be exercised, would "preclude options that involve new investment". This therefore precludes effective and reliable DR. A proper standing reserve programme would be the simplest and cheapest way to improve system reliability, without the need to increase market volatility by raising the Market Price Cap or the Cumulative Price Threshold.

Chapter 9: Networks

36. Do you consider that the current regulatory arrangements could prevent network businesses from pursuing efficient DSP projects which could contribute to achieving a more economically efficient demand/supply balance in the electricity market?

Yes.

Network businesses do not earn a return on operating expenditure on DSP that defers the need for new network capital investment. They do earn a return on capital investment. It should not be surprising, therefore, that NSPs generally do not give more than passing consideration to demand-side alternatives, even when these may be the more cost effective solution.

37. What options for reforming the current regulatory arrangements should be explored under the next stage of the review?

NSPs must be incentivised to use DR when it is the most efficient solution. Simply imposing compliance obligations to carry out prescribed assessments, which has been the approach thus far, does not work, as such assessments can easily be subverted, even without deliberate intent to do so. For NSPs to make efficient decisions on these issues, it must be in their own best interests to do so.

To do this effectively, it is not sufficient just to remove the perverse incentives from the current regulatory regime, as there are cultural barriers to overcome. Rather, it must be clear to NSPs that they stand to make more profit, after adjusting for risk, when they choose the more efficient solution, even if it means that their Regulated Asset Base does not grow. It should be sufficiently compelling that their CFOs will force the necessary cultural change.

Merely persuading NSPs to be enthusiastic about using DR is not enough. It should be efficient DR, procured at the lowest cost. There is a worrying temptation for NSPs to attempt to do everything in house, or through related parties, rather than seeking to engage with other parties. The $/MW/year costs for such in-house or related party solutions can be very high.

41. Is it appropriate for network businesses to be exempt from the service standard incentive scheme during the initial development phase of DSP projects? What factors need to be taken into consideration in designing such an exemption?

Maybe.

Contracted DR is not intrinsically less reliable than network infrastructure: it can be made arbitrarily reliable; there's a simple trade-off between cost and reliability.

However, clearly the reliability of DR is perceived as a problem by NSP staff. Along with a clear financial driver, some kind of exemption might help overcome the cultural barrier to the use of a more efficient level of DR, and help staff develop experience in procuring DR efficiently, rather than avoiding it, or over-specifying it, which makes it unnecessarily expensive. Some experience is required to get this right.

For non-contracted DR, predicting the proportion of the peak performance that can be relied upon is a hard problem, so an exemption would clearly help here.

42. Should network businesses play a greater role in informing consumers about the potential benefits from DSP and various DSP products? If so, how should they do so?

NSPs need to make information widely available. However, we agree that it does not make sense for them to extend their monopoly activities any further than strictly necessary. An information services provider is a better solution to the meter data issue, and vigorous competition to procure DR is an effective way to ensure that consumers are informed about the possibilities.

Chapter 10: Retailers

We do not agree that competition leads to either gentailers or "pure" retailers having an incentive to facilitate DSP. Please refer to our answers to questions 9 and 22 for more details of the issues which prevent such incentives.

We also do not believe it is sensible to conclude, as suggested on pp. 154-155 of the Directions Paper, that for consumers who, due to risk aversion, choose a simple flat tariff, to be prevented from offering DR is somehow an efficient outcome. Demand-side bidding can overcome this restriction.

43. Do you consider that settlement profiles which more accurately reflect actual consumption patterns improve incentives on retailers and/or consumers to offer/provide DSP?

Being charged according to the behaviour of a particular class of consumer that you choose to serve is not the same as being charged according to the actual behaviour of your own customers. In principle, retailers could take action to alter the behaviour of their own customers (although they may not do so, as discussed in our responses to questions 9 and 22). However, if their market exposure is based on the behaviour of a blend of their own customers' behaviour and that of other retailers' customers, there is no potential competitive benefit to be obtained by such action.

45. Should retail price regulation provide some certainty for retailers in their ability to recover any costs associated with facilitating DSP?

Third-party aggregators should be allowed to facilitate DSP and to compete with retailers for the right to provide consumers with DSP services. In such a situation, it would be anticompetitive to provide any cost recovery certainty to retailers that is not also provided to aggregators. Instead, no such certainty should be provided. This will encourage vigorous competition and place the burden of failed decisions or DSP investments where they belong: on the backs of those who make them.

46. Should retailers play a greater role in informing consumers about the potential benefits from DSP and various DSP products? If so, how should they do so?

They should not be barred from doing so. On the other hand, it would be foolish to pin our hopes on them doing so. If the marketplace evolves such that it becomes in retailers' competitive interests to engage with consumers about DR, then we would expect them to become actively involved, so as to improve their own profitability. At the moment, very few retailers do this.

What is essential is to ensure that a retailer who is antagonistic towards DR, as some are always bound to be, is not able to frustrate the participation of its customers in DR programmes. This requires the unbundling of wholesale market DR from retail energy supply: if retailers want to procure DR from their customers (or from any of their competitors' customers) then they should compete for it.

There are also some finer details that could be important, such as access to meter data, and interfacing with meter outputs: it is very easy accidentally to set up a customer's retailer as a gatekeeper to their DR participation, and hence undermine competition.

Chapter 11: Distributed generation

Connection of small market generators

As noted on p.164 of the Directions Paper, as the rules are currently proposed, small generators can benefit from the more straightforward treatment of connection applications under Chapter 5A only if they intend to be an unregistered, and hence necessarily non-market, generator.

If they wish to participate in the wholesale market, they must register with AEMO, and hence must suffer the more arduous and expensive connection regime under Chapter 5.

Clearly, this is a barrier to the participation of small generators in the wholesale market. It seems to be an entirely unnecessary one, arising from an oversight in drafting. This can, and should, be remedied by allowing small generators to be handled under Chapter 5A even if they intend to participate in the market.

47. What incentives should be provided to DNSPs to ensure that they support DG projects? Is there merit in the proposal for DG proponents to pay DNSPs a fee-for-service to connect a DG installation? If so, how should this proposal be applied?

There is some merit in this, as it would avoid the now common scenario in which the DNSP regards the DG proponent giving up as a good outcome.

Since DNSPs will be a monopoly provider of these services, care is required to ensure that the fees are cost-reflective, and that the services are delivered efficiently. It may also be worthwhile placing some simple incentive on the DNSP that rewards them for *successful* DG connections. It seems very likely that there are sufficient positive externalities to greater penetration of DG to make this economically justifiable.

48. What are the appropriate metering and settlement arrangements to facilitate the ability of consumers and DG projects to sell their demand response to any party?

AEMO's Small Generator Framework Design looked at this in detail in 2010.

The issues relating to subtractive metering are embodied in Principle 5: "The regulatory framework for subtractive metering of small market generators should be clarified and, if necessary, differentiated from subtractive metering arrangements in embedded networks generally to facilitate the settlement of small market generators in the NEM." Since then, the AER has revised its Electricity Network Service Provider Registration Exemption Guideline to address some of the issues.

The major remaining barrier to subtractive metering is the installation cost when retrofitting, which can be extremely high due to restrictive jurisdictional requirements on metering which were intended for boundary meters and are awkward to apply to child meters. Revising these requirements may be worthwhile.

The issues relating to metering installations which are shared between loads and generators have not yet been addressed. Similar issues—in which multiple FRMPs have an interest in one meter—arise with the use of load curtailment for DR and with the market participation of electric vehicle battery charging systems. These should now be explored.

We note that the demand-side bidding mechanism proposed in our main submission could go some way to alleviating these issues by providing an alternative option to direct generator metering that may be attractive in circumstances where it is difficult to meter a particular generator installation.

49. Are amendments to the current market arrangements required to facilitate DSP contracts which enable the DSP provider to sell its services to any party? If so, what amendments are appropriate?

Since it is possible to register a small, embedded generator as a market generator, this is already possible for standby generators: their output is fully portable. This is why such DR is already being sourced from such generators for wholesale market purposes, whereas equivalent DR from load curtailment is not.

For cogenerators, however, registration as a market generator is not financially attractive, because they are unwilling to sell all their output on the spot market. There is currently no option, other than negotiating a bespoke deal with their

retailer, who may not be willing, that allows a cogeneration unit to be off-market most of the time, while supplying their baseload, but offer additional peaking capacity into the wholesale market when spot prices are high. If the proposed demand-side bidding mechanism can also be applied to sites with export-capable generators, then it would solve this issue.

It would also be helpful if aggregations of small generators were able to participate as a scheduled resource. This would allow them to become part of the bid stack, and hence receive a more predictable economic incentive than simply earning the spot price while being treated as "negative load". This would also be beneficial for the market operator, in that it would prevent the accuracy of their short-term forecasts from deteriorating as the level of market participation by small generators increases.

Chapter 12: Energy efficiency regulatory measures that integrate with or impact on the NEM

52. In your view, do consumers consider energy efficiency measures separately to DSP, or do they consider all actions as part of managing consumption and hence controlling electricity costs?

EnerNOC believes that customers should view all of their energy management needs holistically, and we encourage customers who may start out by looking at DR in isolation to also consider how they can better manage the other aspects of their energy spend, including energy efficiency and energy supply contracting.

DR tends to be treated differently because it produces actual revenue, rather than just cost savings. However third parties such as ourselves are well placed to suggest energy efficiency improvements to consumers who participate in our DR programmes.

It has been our experience that DR is the "gateway" for many customers to begin looking seriously at energy management. DR provides them with an immediate risk-free revenue stream (EnerNOC absorbs all potential penalties from participation) as well as real-time metering and instantaneous access to their usage data. Armed with this data, customers become sensitised to how they use energy. EnerNOC also offers additional services that take this real-time data and use it to identify low- or no-cost efficiency investments, while their DR revenues provide a means of financing such investments.

53. What are the elements for a best practice model or approach for energy efficiency policy to facilitate efficient investment in, and use of, DSP in the electricity market?

Allow customers, as represented by third-party aggregators, to offer their DR capability into the wholesale energy market on a non-discriminatory basis, comparable to generation. The revenues and energy awareness derived therefrom will, in turn, facilitate the identification and adoption of energy efficiency measures that will further benefit consumers, the market, and the economy as a whole.