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Mr. John Pierce | Chairman
Australian Energy Market Commission
PO Box A2449 | Sydney South NSW 1235
Submitted via www.aemc.gov.au

18 May 2018

Dear Mr. Pierce,

Response from EnerNOC to the Commission's **Reliability Frameworks Review – Directions Paper** dated 17 April 2018 (EPR0060).

EnerNOC is a global provider of demand response services. We work with commercial and industrial energy users to enable dispatchable demand side flexibility, and offer that flexibility directly into wholesale capacity, energy, and ancillary services markets as an independent market participant. In the NEM, EnerNOC is an active developer of demand response in our capacity as a Small Generator Aggregator, a Market Ancillary Service Provider, and Strategic Reserve supplier under the RERT. EnerNOC is grateful for the opportunity to comment on the Commission's Directions Paper. We have provided comment exclusively on the wholesale demand response portion of the Directions Paper.

The Directions Paper well describes the practical barriers that are hindering the development of wholesale demand response and are preventing both existing retailers and prospective new entrant aggregators from making investments that would bring forth new dispatchable demand side capacity. Fortunately, the Commission has presented an option (Option 1) that would effectively lower those barriers and provide wholesale demand response an opportunity to flourish. Importantly, Option 1 would encourage the development of wholesale demand side resources that are able to participate in the market on a level playing field with traditional supply side resources (generators). Option 1 would provide new opportunities for both traditional retailers and new entrant aggregators to innovate, and will introduce new wholesale market competition to the benefit of all consumers. In line with Dr. Finkel's recommendation 6.7, Option 1 should be progressed to a draft rule change proposal for consideration by the COAG Energy Council.

Please reach out to me with any queries related to this submission. EnerNOC would welcome the opportunity to contribute further to the Commission's Reliability Frameworks Review.

Regards,

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The AEMC's "Option 1" is the best option presented, and should be progressed to become a Rule Change Proposal

The Commission's Option 1 (referred to in the Directions Paper as "*Transferring the value of the wholesale demand response from the existing FRMP to the aggregator*[1]") is a suitable option that would do well to lower the barriers that are hindering the development of demand side participation in the NEM's wholesale energy market. Were Option 1 to progress to a rule change proposal, we believe the Commission would have adequately addressed the recommendation given to it by Dr. Finkel in recommendation 6.7.

Option 1 is best because it completely solves the "investment time horizon" problem that the Commission notes may be hindering wholesale DR under the status quo.

The Commission's Directions Paper notes that:

> *"Engaging a consumer to provide wholesale demand response has associated upfront and ongoing costs…. The payback period for these costs may be greater than the terms of the retail contract, leaving the retailer exposed to the risk of not recovering their costs if a customer changes retailer…. As a result, some retailers in the NEM may opt not to utilise wholesale demand response to manage wholesale electricity market risks (or to utilise it less than they otherwise would)... Therefore, while theoretically retailers have incentives to offer demand response products, in practice there may be reasons why retailers have incentives not to offer demand response products. Stakeholders are divided as to what actually is the reality...*[2]*"*

EnerNOC is one such stakeholder that firmly believes that this excerpt describes reality. In the past EnerNOC has worked in commercial partnership with NEM based retailers to assist in developing wholesale DR within a specific retailer's book of customers. On many occasions we had to "discard" prospective customers purely due to the expiry date of the customer's supply arrangement with the retailer. In general, any customer that had less than 12 months remaining on its retail contract was discarded and not approached about wholesale demand response participation – because both EnerNOC and the participating retailer lacked certainty that we would be able to recoup our investment in time and commissioning/controls costs.

The passage in the Directions Paper continues:

> *"If such a statement is true, in order to facilitate more wholesale demand response in the NEM there would need to be more demand side aggregators who could offer demand response products as an alternative to retailers*[3]*."*

[1] Directions Paper, p130

[2] Directions Paper, p123-125

[3] Directions Paper, p125

This statement is not correct. It could be made correct with the following amendments (amendments in blue):

> *"If such a statement is true, in order to facilitate more wholesale demand response in the NEM there would need to be ~~more demand side aggregators who could offer demand response products as an alternative to retailers~~ a method for demand side aggregators and retailers to offer demand response products that extend beyond the end of a customer's retail supply contract."*

Said otherwise, the remedy is neither "more aggregators" nor "an alternative to retailers" but rather fixing the demand response investment time horizon problem. Fortunately, the Commission's proposed Option 1 does exactly that. Under Option 1, Retailer A could equip one of their current retail customers to supply wholesale DR (undertaking all necessary investments in time, IT systems, and hardware deployment) and retain the benefit of that customer's demand response capability even after the customer churns to Retailer B (presumably because Retailer B has offered the customer more competitive rates for energy supply, but less attractive rates for wholesale DR provision). In this scenario, the customer is able to enter into the lowest cost energy supply arrangements through the ability to contract separately with Retailer B for electricity supply, and Retailer A for wholesale demand response.

One way to think of this effect under Option 1 is that "retailers could become aggregators". However it would be more correct to describe the effect as "disassociating demand response provision from retail supply provision". Retailers should find Option 1 an attractive proposition: they can establish long-term commercial arrangements with customers relating to demand response, and maintain those arrangements even after the customer churns to a different retailer. The retailer will retain the value of the demand response capability they invested in, continue to incorporate its capability into their suite of risk management tools[4], and maintain an ongoing commercial relationship with the customer (presumably, with hopes of one day winning back its retail supply business).

Option 1 would provide today's retailers with new optionality that can be leveraged to complement (rather than replace) the retailer's existing customer acquisition and risk management strategy. The most obvious such example is that of residential battery VPP aggregators. The Commission's Directions Paper points to Sonnen's arrangements with Energy Locals, and Reposit Power's arrangements with Diamond Energy, Simply Energy, and Powershop[5]. Under the status quo, these new energy businesses have embarked down a path that requires recruiting battery owners onto specific retail supply contracts, so that battery owners can participate in a VPP and earn payments by participating in wholesale demand response (thus partially justifying the capital expense of

[4] Under this scenario, the only difference is that the value of DR is accrued to the "retailer" (and accounted for in its risk management systems) in the form of a *payment*. This differs from wholesale DR facilitated under today's status quo, where the "retailer" is by necessity also the FRMP – in which case the value of wholesale DR is accrued (and accounted for in risk management systems) in the form of a *savings* (an avoided wholesale purchase from the wholesale market), rather than *payment* from the wholesale market. The net cash positions are the same under either arrangement.

[5] Directions Paper, p127

investing in a battery). Under the Commission's proposed Option 1, these businesses could continue to pursue the same strategy, but they would receive a new, complementary option: retaining a battery owner in its VPP even if the battery owner later churns to a different retailer, in pursuit of cheaper energy supply rates. This has benefits for consumers as well – consumers with batteries or flexible loads avoid needing to be locked in to a long-term arrangement with a specific retailer who, over time, may not be in a position to offer the most competitive energy supply rates - in order to access the wholesale DR value provided by their battery/flexible load.

The term "aggregator" is a misnomer

Under the Commission's proposed Option 1, "retailers" could become "aggregators". In addition, individual (presumably large) energy users could choose to leverage Option 1 independently, and interface with the wholesale market directly, without the assistance of a "retailer" or an "aggregator".

As such we suggest that the Commission's name for Option 1 ("*Transferring the value of the wholesale demand response from the existing FRMP to the aggregator*") requires rethinking, as it is not exclusively "aggregators" to whom value would be transferred. It would be more appropriate to define a new class of participant to whom the value is transferred. We suggest that a term like "Demand Response Market Participant (DRMP)[6]" or "Demand Response Coordinator (DRC)" may be more appropriate.

The possibility of "too much wholesale demand response" is not a legitimate reason to abandon efforts to lower barriers to demand response participation

The Commission's Directions Paper notes:

> "*Just as it is possible to have excess generation capacity, too much wholesale demand response could develop. Market participants could over-invest in utilising wholesale demand response and fail to make a return on this investment. Additionally, a consumer could enter into an agreement to provide wholesale demand response and consequently be required to reduce demand at times when the cost to the consumer of doing so outweigh the benefits of being a party to that agreement*[7]"

While this statement is true, we note that these risks would apply equally to supply side resources and demand side resources. The NEM is a deregulated energy-only market where private investors make investment decisions based on their own long-term forecasts of future spot prices, and wear the consequences of making bad investment decisions. If bad investment decisions are made, such costs are worn by private players, and are not borne by the market.

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[6] In particular, this naming convention has an agreeable symmetry with the existing term *Financially Responsible Market Participant (FRMP).* Under the Commission's proposed Option 1, during a wholesale DR trading interval at a particular connection point, the FRMP would be settled on baseline energy, and the DRMP would be settled on the difference between actual actual energy and baseline energy.

[7] Directions Paper, p128

We note also that demand response is a particularly flexible source of capacity within a market – it can decide to come forth – and also mothball or retire – in particularly short timeframes, compared to traditional supply side resources[8]. An oversaturated demand response market would quickly self-correct. The final sentence in the passage above is analogous to an uneconomic generator. If the costs a generator incurs by remaining in the market (its costs) exceed its revenues (its benefits) the generator is uneconomic, and will choose to mothball or retire. The same is true for demand response – and because in general the capital invested in a demand response installation is far less than the capital investment in a generating plant of equivalent size – demand response's decision to mothball or retire is considerably less consequential than that of a generator.

We also note that wholesale demand response resources are price-sensitive, and will choose to mothball or retire if market conditions result in the costs of participating in demand response exceeding the actual (or perceived) benefits of participating. Western Australia's Wholesale Electricity Market (WEM) provides a useful local and contemporary example of this principle. In 2016 the WA state government imposed legislative reforms to the WEM's Reserve Capacity Mechanism that resulted in demand side resources being able to earn just 15% of what supply side resources are eligible to earn. As a result, as soon as the new rules took effect, 454 MW of certified demand side capacity resources (representing 81% of the certified demand side capacity in WA from the prior year 2016-17) choose to mothball itself immediately and cease participation in the RCM[9]. However, if equitable pricing is reintroduced, we expect a portion of that capacity to un-mothball and resume competing in WA's Wholesale Electricity Market.

Demand side participation **is preferable to** ***demand side response***

We agree with the distinction Stanwell has articulated[10] between *demand side participation* (where demand side resources continuously signal their available quantities and price sensitivities, and participate in spot price formation on an equal basis with supply side resources) and *demand side response* (where demand side resources react belatedly to published spot prices that have been determined using only the offers of supply side resources) and we agree that the former is preferable.

The Commission's Option 1 presents a good first opportunity to progress down this path, and should over time convert much of the NEM's existing *demand side response* into more preferable *demand*

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[8] As examples of this, we would point to AEMO's recent Long Notice RERT tender in mid 2017, which brought forth approximately 640 MW of behind-the-meter demand response resources (i.e. excluding generators that were trucked in temporarily) in less than six months (source link), and the recent AEMO-ARENA trial, which brought forth 143 MW in an even shorter timeframe (source link). We note that these resources sit "outside the market" and that their characteristics are likely to be slightly different to future "inside the market" wholesale DR resources – but the principle is the same: demand response can be mobilised (and demobilised) more quickly than traditional supply side resources.

[9] This 454 MW reduction represented 81% of the certified demand side capacity resources that participated in the WEM during delivery year 2016-17.

[10] Stanwell Corporation Limited, RELIABILITY FRAMEWORKS REVIEW, Response to interim report January 2018, p8

side participation, thus providing a more equal playing field for supply side and demand side resources to compete (against each other, and against all resources) in the wholesale market. In addition, Option 1 will lower barriers and enable participants (existing ones, and also new entrants) to develop greenfield *demand side participation* resources.

Importantly, retailers that are facilitating *demand side response* would have the option to continue doing so, as would any large Market Customer buying directly from the wholesale market.

Option 1's idea to "schedule" wholesale demand response in some manner is a good one

Wholesale demand response resources are able to be scheduled and bid into central dispatch. In fact, it's already happening, in way: the greenfield demand response that has begun participating in the NEM's FCAS markets over the past eight months is a good evidence of this concept. In recent weeks there has been over 100 MW of demand response clearing in the Contingency FCAS markets, brought forth by two Market Ancillary Service Providers (MASP) (both of whom might be labelled "aggregators"). This demand response needs to continually submit bidfiles to AEMO's central dispatch engine, reflective of its quantity availability and price sensitivities in the current and future trading intervals – and is subject to the same market rules and regulatory compliance burdens as the generators with whom it competes.

The forecasting, bidding and rebidding of wholesale demand response resources under Option 1 would be no different. We note that due to the practicalities of continually forecasting available demand response, the mechanics of submitting bidfiles, and the 1MW minimum bid size requirement, it seems likely that most wholesale demand response resources bid in under Option 1 would be aggregations of multiple customers, rather than single customers participating individually.

A new category of *scheduled-ness* may be appropriate for facilitating wholesale demand response under Option 1

EnerNOC's experience with aggregated demand response (primarily using customer load curtailment) indicates that while demand response is as *dispatchable* as a traditional synchronous generator, it is typically not as *controllable* as a traditional synchronous generator.

Said otherwise: in a bid to central dispatch, a demand response resource is capable of signalling its firm commitment to reduce demand by X MW, within Y minutes, and to sustain that reduction for Z minutes (and the various price points at which it is willing to do so), and to deliver on its commitments reliably. However, demand response is not well suited to ramp up and down towards new dispatch targets every five minutes, the way a gas turbine might.

In many ways, the NEM's flexible bidding arrangements are well suited to accommodating wholesale demand response. The ability to rebid quantities based on new information, offer different quantities into each 30-minute trading interval, and to structure quantities across 10 different price bands would well suit an aggregator with a diverse mix of customers, each of whom would have their own varied availability and varied opportunity costs.

While the *activation* of demand response is relatively straightforward for an aggregator to predict and commit to using variables XYZ, the *de-activation* of demand response is typically less predictable. In our experience, while a diverse mix of customers can be coordinated to reduce demand in a coordinated, precise fashion, the same diverse mix of customers will restore to their typical demand levels over more varied time horizons. Some types of loads can resume normal operations nearly immediately, whereas others will restore over many minutes or hours, and this "restoration profile" would be the most difficult variable for an aggregator to represent in a bidfile and adhere to rigorously. Restricting participation to loads which can also be restored in a very controllable manner (by forcing demand response to adhere to the same requirements as a *Scheduled Generator*) would severely reduce the range of customers and the total volumes made available.

To accommodate wholesale DR's characteristics, it may be that the Commission would need to consider a new category of "scheduled-ness". It would be inappropriate to classify wholesale DR as a *Scheduled Generator* for the same reason it is inappropriate to classify a wind farm in that category: DR cannot necessarily be controlled such that it delivers exactly what is requested. Wind farms are *Semi-Scheduled* to reflect that there is an asymmetry in their controllability – they are instructed at times to generate no more than the specified quantity. A similar treatment may be appropriate for wholesale demand response: that when dispatched it should deliver no less than the specified quantity. A variant of the existing *Semi-Scheduled* category may be best suited to facilitate the entry of wholesale demand response into central dispatch.

In any case, we consider that the prospect of scheduling wholesale demand response in some way is certainly achievable, and need not give the Commission pause in its consideration of Option 1. The gritty details of scheduling can be sorted out in a later consultation.

Baselines will be important

The Commission's Directions Paper well describes the important role that baselines would play under Option 1, and the importance of determining accurate baselines and eliminating gaming potential. We understand that Oakley Greenwood has recently been commissioned by ARENA to undertake a study of baseline applicability in AEMO-ARENA Demand Response Trial, and suggest that the results of that study would be useful to inform the progressed design of the Commission's Option 1.

In considering which party is best placed to determine the baseline, the Directions Paper notes that there are two options: AEMO could centrally determine the baseline, or the participant responsible for bidding the DR could determine and submit the baseline. We suggest that the former method is global best practice, and that both options have pros and cons that will provide for stimulating discussion during consultation.

In any case, we consider that baselines are a solved problem – many markets globally have been through the baseline selection process and arrived at workable and agreeable solutions, and there is a wide body of published academic literature discussing the pros and cons to various baseline calculation methods. We suggest that at this stage of its Review, the Commission should consider baselines to be a solve-able problem, and that the gritty details of baseline selection are best left to future stakeholder consultation.

Option 1 is ideal because it closely replicates an existing NEM settlement framework, and thus would require minimal changes to retailers' billing systems.

The settlement method under Option 1 very closely mirrors an existing settlement method that has been operating smoothly for years and has been effective in facilitating the participation of flexible distributed resources in the wholesale energy market – albeit a method that is only able to be utilised by generators: the settling of a market generator behind an embedded network. We will explain how this works in the context of our own operation:

EnerNOC, is its capacity as a Small Generator Aggregator (SGA), has been developing and operating wholesale demand response resources for many years. EnerNOC is the FRMP for a number of behind-the-meter generators throughout the NEM. We use our fleet of generators to sell risk management products to other market participants, and have been doing so since approximately 2010[11]. To equip such a generator to participate in wholesale demand response, EnerNOC creates an embedded network behind the connection point. Next, we install a revenue meter at the behind-the-meter generator, create new NMI for it (with EnerNOC as its FRMP), and designate the NMI as a child of the embedded network. Each time the generator runs, EnerNOC (as FRMP for the child NMI) collects the spot price for the generated energy (metered energy * RRP), and uses the spot revenue both to compensate the customer[12] and to settle the risk management products we have sold.

At the same time, the customer's retailer (the FRMP for the *parent* NMI) charges the customer for the energy that the customer *would have consumed from the grid*[13] at the customer's regular retail rate. This is because a generator within an embedded network is effectively treated in AEMO's settlement processes as a "negative load", which results in all energy measured on the child NMI's meter being "added back" (automatically, during retail settlement) onto the parent NMI. The effect is that the customer buys the same amount of energy from their retailer, as if they hadn't run the generator at all. [14] Retailers' billing systems already accommodate this type of settlement automatically.[15]

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[11] Some of our generators pre-date the SGA framework, and so are registered as individual power stations on AEMO's participant list.

[12] "customer" meaning the energy user who owns the embedded generator

[13] This is effectively "counterfactual" energy.

[14] The same is not true for the energy charged by the Customer's DNSP - because the generated energy does not travel the distribution network, the customer is not charged for this energy by their DNSP, and it would not affect their demand charges, etc.

[15] When we started the programme in the late 2000's, a couple of retailers had not considered the possibility of a market generator sitting behind an embedded network when they designed their billing systems. These retailers were clearly using a manual processes for adding back the child NMI's generated energy onto the parent NMI. After discussion, we arranged to send affected retailers automated notification emails so they knew which settlement intervals were affected. However, none of the retailers require these automated email

So, under this scenario:

- A customer is able to participate in wholesale demand response without the consent of their retailer
- A third party aggregator is able to make a multi-year investment in commissioning the customer's facility with appropriate enabling technology, with certainty that this investment is disassociated with the customer's retail arrangements and retail contract time horizon
- The third party aggregator has nothing to do with the customer's choice of retailer[16], and the customer is always free to churn between retailers in pursuit of the cheapest supply arrangements
- The customer's retailer (FRMP) sells no more and no less energy to the customer as a result of the customer's wholesale demand response participation[17]
- The market supply of risk management products has increased

The only shortcoming is that this framework only works for generators that can be metered with a revenue metering installation, and there is no parallel for loads. Fortunately, the Commission's proposed Option 1 fills this exact gap. Option 1 simply replicates this exact concept, but for loads. There are only two differences between settlement under the Commission's proposed Option 1, and settlement under the existing "market generator behind an embedded network" method:

1) Instead of attempting to measure the wholesale demand response energy with an incremental dedicated revenue meter[18], you measure it by calculating the baseline energy, and then subtracting the actual energy.
2) Instead of creating a new NMI (i.e. a separate connection point) for the demand response energy, the original single NMI is utilised, and both counterfactual energy and actual energy are calculated by AEMO and stored in its settlement systems, along with a binary TRUE/FALSE flag indicating whether the trading interval is a demand response interval, or

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notifications anymore, so they have presumably automated their processes as part of the routine upgrades of their settlement and billing systems. We expect that Option 1 might require some retailers to make similar minor changes to their settlement systems or processes, and that these changes are easily accommodated with manual processes in the short term, and easily merged into regular system upgrades in the medium term. Retail billing systems have been modified to accommodate wholesale demand response in the past without fuss, so we see no reason why they can't be modified in the future to accommodate Option 1.

[16] In fact in almost all cases EnerNOC is ignorant to who the FRMP is for the majority of our generator DR customers – we don't have a reason to know, and we don't care – as it's immaterial to our operation of the wholesale DR asset.

[17] And in many cases, we suspect the parent FRMP is ignorant to the fact that EnerNOC is involved, and actively facilitating wholesale DR at their retail customer's premises. In order to even notice, the parent FRMP would need to dig deep into their automated billing systems to inspect/notice the automatically "added back" child NMI energy.

[18] This is necessary because it is impossible to measure/meter load curtailment directly: it always involves a counterfactual.

not[19]. In meter data and settlement files, this data could be passed from AEMO to the retailer in such a way that the retailer easily and automatically settles on the "correct" energy (and on-bills their customer for "correct" energy), and where the retailer is presented with all the information it would require if it wanted to investigate when wholesale DR occurred at their customer's premises.

We expect that inevitably, some stakeholders will cry foul on the basis that Option 1 would require them to modify their IT and billing systems in some manner, and that these modifications will require exorbitant expenditures, the costs of which will be borne by the retailer's customers. As the Commission considers such feedback, we suggest that the Commission consider that:

1) The forthcoming implementation of *Five Minute Settlement* will necessitate far more dramatic changes/upgrades to settlement and retail billing systems, and that any system changes necessitated by Option 1 could be easily and cheaply shoehorned in alongside these planned upgrades.

2) That if a retailer maintains an ancient and inflexible billing system that costs a fortune to modify, that's their problem. The fact that some billing systems are ancient and expensive to modify is not a legitimate reason to suppress innovation. If such a retailer passes on the costs of 'Option 1' related IT changes to its customers, those customers can choose not to pay those costs, by switching to a more efficient retailer who has invested in modern billing systems and for whom the Option 1 changes necessitate no extra pass through costs.

3) That 'Option 1' is very similar to settlement that is already occurring today, and which retailers' systems have already been upgraded to accommodate (without fuss).

The Singaporean model is not suitable for the NEM and is inferior to Option 1

Most fundamentally, the Singaporean model does not provide a level playing field for demand side resources and supply side resources to compete against each other and participate in spot price formulation. Said otherwise, it is not true *demand side participation* relative to the Commission's Option 1. The Singaporean regular refers to the model as a "demand response *program*[20]" – the Commission should not be endeavouring to create a special program for demand response in the NEM – it should instead focus on providing it a level playing field to participate in the wholesale market in the same manner as a generator.

Further, the Singaporean model would limit a demand response resource's ability to sell risk management products (which is likely to be the foundational business model of any future DRMP in the NEM under Option 1) because wholesale DR doesn't earn the spot price, it earns an "uplift payment" of unknown (and thus un-bankable) magnitude. DR resources aren't paid their bid price or

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[19] Under Option 1 where the wholesale demand response is scheduled in some way, these flags are easily determined in automated fashion. In any trading interval where the DR resource cleared the market, the flag would automatically flip TRUE.

[20] Directions Paper, p135

the clearing price multiplied by their own quantity of load reduction (as would occur under Option 1), rather they are rewarded with a payment of a magnitude that is unknowable in advance, because the payment is based on a calculation of consumer surplus that is partially determined by the (private) bids of the other generators online at the time, and the (unknowable) amount of market-wide contestable load the time. Next, the calculated consumer surplus is reduced arbitrarily by 66% before being distributed to demand response suppliers, in proportion to each supplier's proportional contribution (which is also un-knowable at the time of commitment).

The Singaporean method is further problematic because it effectively requires all participating wholesale demand response resources to become scheduled loads – constantly forecasting and signalling their planned consumption and penalised for any deviations. Loads in the NEM already have the option to classify themselves as Scheduled Loads – and the option has been historically unpopular – such that hardly any loads have ever classified themselves as such. In 2017 in the *Non-scheduled generation and load in central dispatch* rule change proposal, the Commission knocked back a proposal that would have taken the NEM down this path. Forecasting available demand response is entirely different to forecasting and committing to future consumption, and any requirement to schedule a load's consumption in order to participate in demand response would effectively rules out participation by customers with volatile loads, as the aggregator is exposed to penalties 8760 hours a year, rather than just during bid (and cleared) demand response intervals, which may only occur in the 10's of hours per year, at times that are somewhat predictable.

It is also notable that the Singaporean approach simply considers any reduction in wholesale prices to be a benefit to all consumers. This has not typically been the view taken in the NEM, where this could be considered a subsidised programme.

The Commission's proposed Option 2 is inferior to Option 1, because it is already possible today, and it simply requires DR aggregators to become retailers (FRMPs), and buy energy.

Option 2 is inferior to Option 1 for these reasons:

1) DR aggregators would have to become retailers in order to obtain value from facilitating wholesale DR. The means the "aggregator" needs to buy energy from the wholesale market 99% of the time, so that it can assist the customer in achieving a wholesale savings that might occur 1% of the time. The "aggregator" would need to post prudentials, obtain a retail billing system, issue customer bills, learn the CATS/WIGS procedures, and completely transform itself into a retailer – which defeats the whole purpose of a new wholesale DR mechanism that separates retail supply provision from demand response provision.

2) Option 2 is already possible today. Any participant with a retail licence can create an embedded network with a new child NMI, and serve as the FRMP for that child NMI, and implement a wholesale demand response strategy for the loads behind the child NMI. EnerNOC has never heard of any participant undertaking an installation like this – which suggests to us that Option 2 would not fix the problem the Commission is trying to solve.

3) Option 2 wouldn't provide a way for aggregators to sell risk management products to the market, Because the value of wholesale DR accrues in the form of a *savings*, instead of a *payment*.

4) Option 2 requires the installation of a revenue meter, which almost assuredly will preclude residential scale customers (i.e. residential battery VPPs) from utilising Option 2. The purported benefit under Option 2 of not needing to establish an embedded network, and not needing to establish a second NMI (connection point) is negligible – the real burden is the requirement for the additional revenue metering installation[21].

5) Many facilities would require expensive re-wiring, in order to isolate the "flexible" portion of the load that is to be equipped with its own revenue metering installation and NMI. For the vast majority of the flexible loads EnerNOC has equipped in Australia, configuring Option 2 would require re-wiring, and in many cases this would be prohibitively expensive, because the load reduction occurs simultaneously at multiple pieces equipment located in disparate parts of the facility.

6) Option 2 requires a customer to engage two "retailers" (two FRMPs, anyway), effectively doubling the customer's administrative cost of managing their energy spend. They would receive and have to pay two bills every month, and would have to aggregate them together in order to undertake any "facility level" reporting on the facility's consumption and/or energy expenditure[22]. For a busy family like the Kerrigans cited in the Commission's Directions Paper – Option 1 is likely to represent a more attractive proposition – Under Option 1 the Kerrigans would keep paying their single retail bill just as they always have, but then receive periodic payments from the third party who has organised the demand response participation of their pool (room?) pumps.

The Commission's proposed Option 3 is the worst option of all

The idea to "create a retailer incentive fund or scheme[23]" is a far inferior solution than Option 1. The Commission's prior publications on wholesale demand response have repeatedly commented that "there is also no evidence that there are insufficient incentives on retailers to offer demand response services[24]". Retailers don't need new or better incentives, they simply need their barriers lowered. Their primary barrier is the "investment time horizon" problem – which would be completely solved by Option 1. Further, Option 3 would still require customers to churn onto specific retailers in order to pursue participation in wholesale demand response, and it would unfairly smear the cost of the scheme across all consumers.

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[21] By this we mean not only the cost of the meter itself and ongoing meter data provisioning services, but the alterations to switchboards to allow a meter to be installed in the necessary part of the site's topology in a way which is compliant with the relevant state's service and installation rules, including location, sealability, height from the floor, etc. Often there's a significant amount of physical rework to the premises required, and sometimes hours of power outage.

[22] Including any reporting that might be required under regulatory scheme - NGERS, etc.

[23] Directions Paper, p142

[24] AEMC, Final Rule Determination, National Electricity Amendment (Demand Response Mechanism and Ancillary Services Unbundling) Rule 2016, 24 November 2016, p7