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Mr Simon Middleton
Program Director, Electricity Market Review
Department of Finance
Level 1, Albert Facey House
469 Wellington Street
Perth WA 6000

Submitted via email: electricitymarketreview@finance.wa.gov.au

29 January 2016

Dear Mr Middleton,

EnerNOC welcomes the opportunity to comment on the important issues raised within the PUO Position Paper[1]. We hope that our comments will be useful to the Steering Committee, and trust that the positions presented will be duly considered when drafting the final recommendations.

EnerNOC is a leading provider of energy intelligence software to utilities and commercial and industrial enterprises. EnerNOC and its employees have participated in the Western Australian Wholesale Electricity Market (WEM) since 2007. We have actively engaged WA consumers to reduce their energy costs, and have worked with these customers to harness and offer their demand-side flexibility into the Reserve Capacity Mechanism (RCM).

The customer providers of Demand Side Management (DSM) capacity span the breadth of WA business and industry: from resources to health care, data centres, and food production through to agriculture, schools, and heavy industrial operations. All sizes of business operations participate from small business through mid-size enterprises to the largest operations in existence in WA, employing tens of thousands of employees across the State.

Our commitment to seeing customers derive maximum benefit from efficient competitive markets has driven our persistent engagement with the Electricity Market Review (EMR) process. Our primary goal throughout has been to support evidence-based policy development for the South West Interconnected System (SWIS) that will lead to the best policy outcomes for Western Australians. This objective is core to our comments herein.

In this spirit, we have commissioned two separate and independent research reports from leading consultancies to provide the broadest perspective on the issues under consideration[2].

Upon completion of Phase 1 of the Electricity Market Review, the Government recognised the merits of a Capacity Market in Western Australia. However, it also recognised the need to undertake reform to improve critical aspects of its operations. One of the key aspects identified almost unanimously by

[1] Position Paper on Reforms to the Reserve Capacity Mechanism, Department of Finance, Public Utilities Office, 3 December 2015
[2] Spees, Newell and McIntyre ("Brattle Group"); "Western Australia's Transition to a Competitive Capacity Auction", 29 January, 2016. Hennessy, DNV GL, "Analysis of Proposed Capacity Baseline Methodology for the Western Australian Wholesale Electricity Market", 28 January 2016. (DNVGL) formerly KEMA

stakeholders, including the Government, was the need to reform Synergy. Sadly, the current PUO Position Paper is silent on this key topic.

Phase 2, including the PUO Position Paper, seeks to address a number of issues identified through the Phase 1 process. As detailed in this submission, the PUO Position Paper's recommendations fail to truly address core market issues, and represent a significant missed opportunity to enact impartial, evidence-based policy reform that truly seeks to promote the long-term interests of WA consumers.

When discussing the key recommendations of the PUO Position Paper, it is important to recognise that there are two distinct time Periods:

- Period 1: Transition period
- Period 2: Future Capacity Auctions

While a number of the recommendations slated for the longer-term Period 2, including a wholly competitive capacity auction, adhere to global best practice, the Transition period proposals depart significantly from best practice and severely impact the outcomes necessary for a successful progression to Period 2 activities. A failed Transition period will undoubtedly undermine the Government's objective to achieve its final end state of *bona fide* market-based reform in Period 2.

The core problem of the PUO Position Paper is the deeply flawed approach to a Transition period, which, if implemented as proposed in the paper, will inevitably serve as a barrier to reform of the WA market structure. The Transition period is so deeply flawed in fact, that the desired goal of getting to Period 2 will inevitably fail. The Transition period will spawn a new WA energy crisis that will create reliability emergencies and result in unsustainably high electricity costs – all spawned by the Government's adoption of flawed policies. Fortunately, there are viable policy alternatives available that will prevent the Government from making a catastrophic mistake.

As detailed in this submission, if the proposed recommendations within the PUO Position Paper are implemented, the Transition period will:

(a) Discriminate against DSM, significantly undermining market efficiency;
(b) Create a perverse disincentive for the retirement of inefficient generation plant;
(c) Result in the forced exit of virtually all DSM;
(d) Prevent the transition to a capacity auction in Period 2 by providing an incentive to remaining capacity providers to introduce new / refurbished capacity in order to avoid the auction trigger of a certain quantity of excess capacity (5-6%);
(e) Result in an overall cost increase for WA consumers; and
(f) Introduce immense regulatory and investment uncertainty and risk for all current and prospective market participants.

Unfortunately, it is Western Australian consumers who would bear the negative impacts of these deeply flawed proposals. Instead of genuine reform, the proposals would result in a wealth transfer from WA consumers to incumbent power generation resources – the largest by far being owned by the Government through its ownership of Synergy. The proposals will further discourage private sector investment, and destroy innovation and resource diversity in WA.

The proposals provide clear evidence of the grave conflict of interest that arises from the Government's ownership of Synergy and its control of the EMR policy-making process. This conflict becomes personified with the Executive Chairman of Synergy acting as the sole industry representative on the Phase 2 Steering Committee.

We respectfully suggest that core elements of the PUO Position Paper be rejected given the inevitable harm they will cause WA electricity users and the broader State economy. Herein we present specific alternatives based upon global successes and best practices in meeting the challenges now faced by WA. We support further exploration of these and other policy reform alternatives for implementation as soon as is practicable.

Please do not hesitate to contact either Richard Wilson (Director, Government Affairs) or myself if you have any queries.

Yours Sincerely,

Mottel Gestetner
Senior Manager, Regulatory Affairs

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1 ELECTRICITY MARKET DESIGN AND ITS RELEVANCE TO THE CURRENT REVIEW

History has shown that competitive electricity markets have provided the best outcomes for consumers, and delivered the most efficient signals for entry and exit of capacity.

As noted in this submission's introduction, EnerNOC recognises that the PUO Position Paper placed a strong emphasis on the introduction of a competitive capacity auction that embodies the principle of market competition, transparency, and non-discrimination. However, the recommendations that relate to the Transition period jettison these same principles in a manner that will undermine the ability to implement essential principles of market competition. The proposed Transition period is directed by the heavy hand of government intervention in order to prop up Synergy in a manner that is anathema to competition and to private sector investment. If the Government intervenes to bail out Synergy as a market participant in WA (whether called a "Transition period" or not), private investor confidence in a free, fair, and open competitive market in WA will have been deeply impaired.

The nature of the PUO Position Paper's recommendations warrant a review of some of the foundational principles relevant to capacity markets and the critical role that demand side management (DSM) can play in operating an efficient market.

1.1 A Capacity Market or Mechanism Has a Defined Role

Capacity is capacity.

A capacity mechanism or market has a defined purpose: to ensure that sufficient capacity is available to meet reliability objectives, at minimum cost.

For this reason, the "capacity product" is an option to call for energy at **times of scarcity**. As such, capacity prices only provide signals about the **quantity of capacity** that will be needed to alleviate scarcity: they give no indication of the **type of capacity** that's needed (outside of scarcity events).

The paper *Capacity Markets – Lessons Learned from the First Decade,* prepared by Brattle Group, the world's preeminent expert on capacity markets, explains that all types of resources should be treated equally:

> *"Different types of generating resources may in fact have very different costs, net energy revenues, and asset values due to their age, efficiency, fuel cost, flexibility, emissions, capital expenditure requirements, and expected life. However, as long as two resources are interchangeable within any particular year for meeting the reserve margin requirement, an efficiently competitive market construct should award the resources the same capacity payment[3]."*

It is the combination of the price signals in the capacity, energy, and ancillary services markets that should ensure the optimal quantity and mix of resources and attract investments in the types of capacity needed to serve load efficiently across all hours of the year. Every resource in a market

[3] Spees, Newell, & Pfeifenberger, Capacity Markets – Lessons Learned from the First Decade, Economics of Energy & Environmental Policy, 2(2), p. 22

optimises its participation in the capacity, energy, and ancillary services markets according to the operating parameters of the particular resource. Investments in new resources are determined by this optimisation and that is how markets attract the right types of resources to meet system needs. Importantly, these markets are indeed separate but inseparable – one does not exist without the other and this results in one market directly affecting all other markets. Accordingly, flaws or market distortion in the design of one market will affect other markets for a negative end result. Flawed market designs attract the wrong types of resources and lead to over- and underinvestment that can threaten reliability and raise system costs.

1.2 Load Duration Curve Instructs the Type of Capacity Required

Given the extremely "peaky" nature of the Western Australian electricity market, DSM is particularly valuable, and significant DSM participation is economically efficient.

Concerns and allegations have been raised that WA has too much DSM. Such concerns are unfounded as they completely ignore the shape of electricity demand in WA.

Ideally, any power system should have a resource mix that is appropriate for its load-duration curve. Baseload demand should largely be met by baseload generation, mid-merit demand by mid-merit generation, peak demand by peaking generators, and extreme peaks by DSM.

A system with an extremely peaky load-duration curve should have a relatively high proportion of peaking plant and DSM. Any other outcome would be economically inefficient.

Any discussion about the infrequency of DSM dispatches misses the point. Peaking resources are needed to cover peaks in demand or periods where forced generation or transmission outages threaten system reliability. Fortunately, such events do not happen very often. The planning criterion for the WEM is based on scenarios with a 10% probability of exceedance. Hence, if forecasting was perfectly accurate, and there was no excess capacity, we would expect the last megawatt of capacity to be dispatched on average only once in ten years.

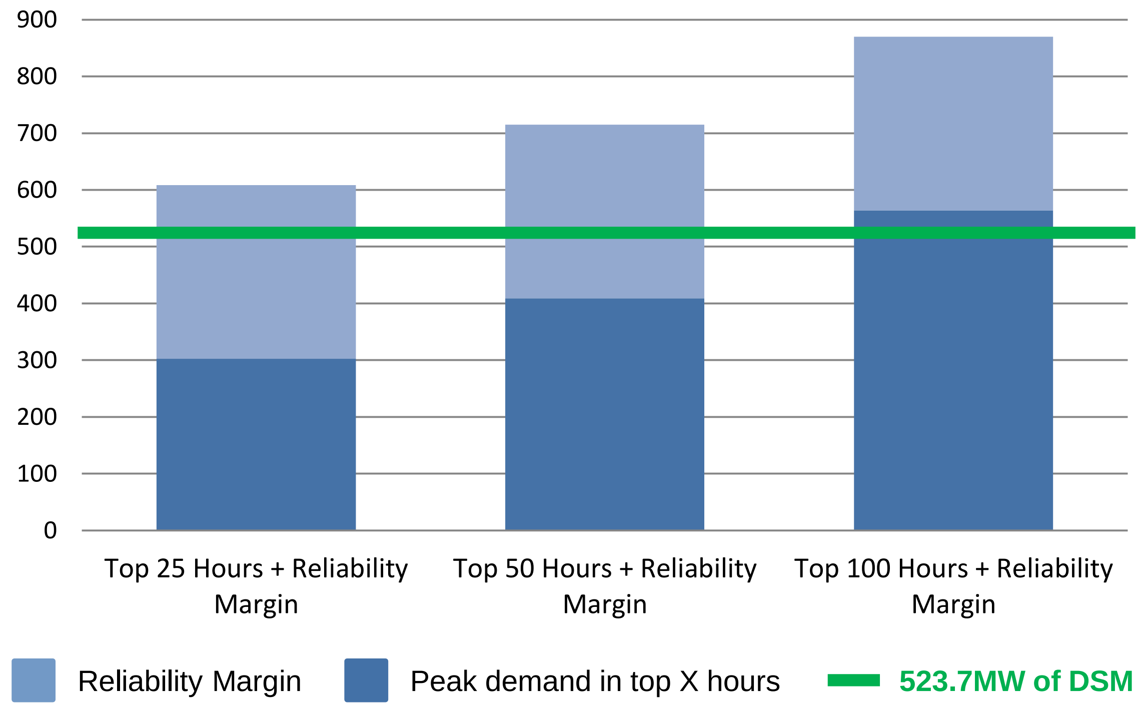
If there is anyone that is uncomfortable with the idea of the last MW of capacity in the system receiving a capacity payment, that person has a fundamental issue with the idea of a capacity market design, not with DSM specifically.

As presented in the figure below[4], the amount of DSM in the WEM[5] is at an efficient level when matched against the Load Duration Curve. By this, it is meant that the amount of actual DSM capacity is at a similar level (less, actually) to the amount of "super-peaking" demand in the WEM (peak demand in the top 25 hours + 7.6% reliability reserve margin).

[4] The data is based on the TT30Gen files

[5] EnerNOC analysis of market capacity credits estimates this as 499.786 and 523.7 in the respective capacity years.

Figure 1: 2014/15 Super-peaking Demand in the WEM compared to installed DSM capacity (MW)



As stated elsewhere, the expected outcome of the proposed changes in the PUO Position Paper will be the exit of virtually all DSM capacity from the WEM. If this occurs, other forms of capacity in the WEM would have to be available to provide such super-peaking capacity.

This implies that the PUO believes it will be more efficient for generation capacity, rather than DSM, to provide the required super-peaking capacity. This is both counterintuitive and counter to the actual experience of every other capacity market in the world.

2 DIFFERENTIAL PRICING FOR DIFFERENT TYPES OF CAPACITY DISTORTS THE MARKET

During times of scarcity, all forms of capacity – baseload, mid-merit, and peaking, including DSM – provide the same value to the system.

For the market to pay different capacity prices to these different technologies would introduce a market distortion that would inevitably lead to inefficient costs and inefficient resource investment.

A differentiated capacity payment based upon classifications of resource types will create a bias in suppliers' overall costs of operation and impact the bids suppliers will submit in the energy and ancillary services markets. These changes to bids will prevent the system from being dispatched in accordance with the true economic merit order, and in turn, distort the investment signals from the energy and ancillary services markets. Attempting to misuse the capacity market in this way – to usurp the role of the energy and ancillary services markets in attracting the appropriate forms of investment – would hence be deleterious to the market as a whole.

Any suggestions that a higher capacity price should apply to some forms of capacity, based on their availability to run in the energy and ancillary service markets, is broadly repudiated by expert economists in the field of energy market economics. Efforts to differentiate capacity payments to bias the procurement towards particular technologies are not market-based, and will lead to less efficient, higher-cost outcomes[6].

Treating the top end of the load-duration curve on an energy-only basis would be akin to attempting to buy insurance only after you have been robbed but expecting to pay the same price as prior to the burglary. Nobody will provide cover on that basis.

With regard to DSM in particular, Professor Joskow's examination of electricity markets concludes:

> *"To fully restore appropriate incentives to market participants, the demand side of the market should be treated symmetrically with the supply side. Demand response resources that are compatible with the system operator's reliability criteria should be compensated at levels equivalent to what is paid to generators to make capacity available during capacity constrained periods.* [7]*"*

Generators and DSM both provide Reserve Capacity. Hence they should both be paid the Reserve Capacity Price. Any other treatment would be discriminatory.

Discriminating against DSM or any other new energy technology is not the answer the EMR should seek. It would be contrary to existing Market Objectives that expressly seek to avoid discrimination against particular energy options and technologies[8], and also against the best practices observed in all other capacity markets around the globe.

By focusing on a particular technology for discriminatory treatment, the PUO Position Paper sets a precedent that would result in the need for multiple markets for different types of technologies – including new energy technologies (e.g. storage technologies) that are emerging or have yet to enter the market. Discriminating against new energy technologies flies in the face of recent global commitments to actively deal with climate change and embrace all technologies that can assist in this endeavour. The State's regulatory framework should support technology neutrality, and not necessitate bespoke treatment for the addition of each new technology class.

The PUO Position Paper details a range of discriminatory approaches with regards DSM, evidenced by such comments as:

> *"Such a low level of "expected dispatch" highlights the low value of demand side resources during this current period of surplus capacity.*[9]*"*

Focusing upon the likelihood of DSM dispatch, without making any comment about the same likelihood facing other forms of peaking capacity, or perhaps the excess baseload capacity that is driving the surplus, is the root of a misplaced bias which unfortunately infuses much of the PUO Position Paper's discussion and recommendations with regards the Transition period.

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[6] Capacity Markets – Lessons Learned from the First Decade, op. cit., pp. 21-22.

[7] Joskow, *Capacity Payments in Imperfect Electricity Markets: Need and Design*, utilities Policy 16(3), 2008, pp. 159-170

[8] WEM Market Rules 1.2.1 (c) "to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions"

[9] Position paper on reforms to the Reserve Capacity Mechanism, PUO, 3 Dec 2015, pg. 48

3 PRICE DISCRIMINATION WILL DISTORT INVESTMENT AND EXIT DECISIONS

3.1 Discrimination Will Lead to the Exit of DSM From the WEM.

Despite justifying the delay of a capacity auction in order to ensure generators can avoid unsustainable price shocks, the EMR does not apply the same principle to demand-side resources that have invested in this market in good faith and consistently delivered against their obligations.

Concerns were raised in the PUO Position Paper that an immediate move to the preferred auction arrangements would be "financially disruptive for participants and create risks for the sustainability of the market as a whole."[10]

It appears that the PUO does not hold the same concern for DSM providers – hard-working Western Australian businesses – that are the most economically efficient capacity resources to meet system reliability needs. The proposal is discriminatory against DSM – slating it for certain exit from the market – without even attempting to demonstrate that it is the most economically efficient resource to retire.

The very real outcome of the removal of DSM from the WEM would be a propped up capacity price and an over $100 million annual increase [11] in total consumer costs. The inflated capacity price would deliver an unintended (we assume) signal that will encourage the investment in new or refurbished capacity when it is a) unneeded, and b) potentially less cost-effective than DSM.[12]

Such outcomes of the proposed Transition period are the antithesis of the PUO's stated objectives.

3.2 Global Precedents for DSM's Exit on Account of Reduced Capacity Pricing

If DSM exits the market, the resulting impact will be to undermine all of the EMR's stated objectives (see Section 5). Unfortunately, the PUO's proposed pricing for DSM will guarantee that virtually all DSM capacity will exit the market.

It has been covered in Section 2 that the proposed discriminatory pricing approach for DSM is in direct opposition to the WEM Market Objectives, global best practice, and the principles of efficient market economics. The practical impact of the PUO Position Paper's DSM pricing proposal, were it to be implemented, is considered in this section.

Assuming that the PUO's unstated goal is not to force the exit of DSM from the market, its pricing proposal seems to suggest that the PUO believes that DSM resources will be happy to stay in the market at nearly any capacity price. Both economic principles and real-world experience prove that this belief is unfounded and wrong.

Beginning with economic principles, NERA Economic Consulting has published an exhaustive whitepaper[13] that demonstrates the critical role availability payments play in ensuring efficient levels

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10 See PUO (2015), p.13.

11 Spees, Newell, McIntyre, ("Brattle Group Letter"), Validating EnerNOC Calculations of Customer Cost Impacts under the Proposed Western Australia Transitional Capacity Mechanism, January 15 2016.

12 Brattle Group at 3

13 "The Continued need for availability payments" NERA Economic Consulting, October 23, 2013, Jonathan Falk, Vice President. See http://www.nera.com/publications/archive/2013/effective-use-of-demand-side-resources-the-continued-need-for-a.html.

of DSM participation in global markets. NERA uses both the principles of behavioural economics and data from global markets to make a clear and compelling case.

In addition, data from global capacity markets clearly demonstrates that DSM resources have a significant cost structure, as evidenced by the fact that DSM resources have consistently chosen to exit global capacity programs when pricing falls below certain levels. To cite one example, the recent 2018 Capacity Auction in the United Kingdom is illustrated.

For the referenced auction, 898MW of DSM capacity prequalified to participate in the auction. The auction process commenced and proceeded with a clearing price reached at approximately AUD$38,000/MW-year. Prior to reaching this clearing price, approximately 629MW of the DSM capacity that had prequalified chose to exit the auction. **That is, around 70% of DSM capacity made the decision that AUD$38,000/MW-year was not a sufficient price to cover its capital and operating costs. To put this price in perspective, this is approximately 271% higher than the capacity price the PUO has proposed to pay DSM in WA.**

Any reasonably diligent and fair consideration of DSM's pricing behaviour in global markets will confirm the view that the PUO Position Paper's pricing proposal would result in the exit of virtually all DSM resources from the WEM on economic grounds alone.

4 DSM's PERFORMANCE AND ITS DISTINCTIVE ATTRIBUTES AS CAPACITY

System emergencies have occurred even when there appeared to be significant excess capacity in the WEM; DSM has delivered in WA and around the world.

It has become part of public commentary that DSM is never used (and that it never will be when reserve margins are high), with the implication being that DSM is not a "real" resource like generation (and therefore should not be compensated accordingly). The issue of discriminatory compensation has been covered throughout this submission. In this section, DSM's dispatch performance and its distinctive attributes as a capacity resource are highlighted.

All claims that DSM capacity has not been dispatched are false, and they fail to recognise DSM's performance over recent years.

In 2011, DSM was dispatched across four days in response to Cyclone Carlos which caused gas supply interruptions off the North West coast of Western Australia. In this case, **100% of the DSM capacity was dispatched across consecutive days, even though the excess capacity in the WEM at that time was calculated to be 8.7% (implying a reserve margin at the time of 16.3%)**. DSM delivered on its commitments, and the situation highlights a key benefit of DSM relative to other forms of peaking capacity in the WEM, namely fuel diversity. If the 154 MW of DSM had instead been an additional 154 MW of gas-fired peaking power plants, those plants would have been stranded without fuel and the emergency may not have been effectively handled.

More recently, the failure of the Muja transformer in 2014 resulted in the dispatch of a portion of EnerNOC's DSM portfolio**.** In this instance, **the system requirement necessitated the dispatch of**

DSM in a specific geographic location[14] even though the calculated excess system capacity in the WEM at the time was 23.7%. This dispatch highlights a second unique capability of DSM, namely that the distributed nature of the resource allows it to be flexibly dispatched in specific areas of the system when network capacity issues arise.

In addition to highlighting several distinctive attributes of DSM resources relative to generation, these dispatches highlight how unpredictable electricity systems can be, especially relatively small and isolated systems like the WEM. This unpredictability has led to DSM being dispatched at a higher rate than would be expected simply by looking at the system reserve margin.

Globally, EnerNOC's DSM capacity is consistently dispatched and it consistently proves its reliable performance. In 2014, EnerNOC's global DSM portfolio was dispatched approximately 425 times, with the capacity provided across these events adding up to ~27.4 GW. On average, EnerNOC delivered 104% of its certified capacity amounts.

Relative to generation, DSM resources offer inherent fuel security, locational flexibility, very low (if any) emissions, and very high reliability. In light of this, it is extremely puzzling that the PUO Position Paper is pushing proposals that will force the exit of DSM capacity from the WEM. This confusion is amplified when one recognises that the exit of DSM will also increase system costs by more than $100 million per annum (see Section 5.4).

5 TRANSITION PERIOD APPROACH IS DISCRIMINATORY REDUCING ECONOMIC EFFICIENCY

5.1 Objectives of the Transition period

Any transition to a capacity auction must deal with excess capacity in a holistic manner – simply targeting one type of technology would not meet the EMR's objectives and would disenfranchise Western Australian businesses providing that technology.

Between the current reality of significant excess capacity and correspondingly excessive costs that have resulted from political and administrative decisions, and the laudable end state of an auction-based capacity market that relies on market principles to achieve reliability objectives from the most economically efficient mix of resources at the lowest overall cost, must lie a transition mechanism.

Of necessity, the goals of such a mechanism must be:

1. Discouraging the addition of economically inefficient new investment
2. Encouraging efficient exit of inefficient existing capacity
3. Transitioning to a best-practices auction

Furthermore, the PUO Position Paper states that these goals should be accomplished in a manner that minimises disruption to the electricity market[15]. EnerNOC retained The Brattle Group ("Brattle Group"), generally acknowledged as the international expert in electricity markets generally and

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[14] The ERA in their 2015 report to the Minister noted that the ability for the localised dispatch of DSM would improve System Management's efficient dispatch. See http://www.erawa.com.au/cproot/13960/2/2015%20WEM%20Issues%20Paper.pdf

[15] PUO Paper at 45

capacity markets specifically, to review the PUO Position Paper's Transition Period approach to determine its effectiveness in meeting the above-stated goals.

Brattle Group's separately filed analysis confirms our determination that the transition mechanism will not achieve its aims. To the contrary, the proposed Transition period will achieve the exact opposite[16]:

- It will result in a price signal to existing generation capacity that incentivises the continued market participation, including of inefficient plant: "This will create incentives for generators to undertake high-cost retrofits to uneconomically prolong the life of the unit even under current overbuilt conditions."[17]
- It will result in the removal of demand response without having demonstrated that such demand response capacity is less economic than generation: "The proposal instead targets demand response, but without having demonstrated that all demand response is less economic than all generation"[18],
- It will increase total consumer costs. "excluding DR from the RCM transition mechanism would increase RCM payments to generators by $154M million per year"**[19]**
- It will delay, perhaps indefinitely, the implementation of the desired capacity auction mechanism: "Very large portfolio owners could even decide to invest in new capacity if needed to support excess capacity above 5-6% and maintain transition pricing…. The efficient auction mechanism outlined so nicely in the PUO's paper could remain an elusive target that is never adopted" [20]

As Brattle Group explains, the root cause of this failure lies in the PUO Position Paper's recommendation that DSM be treated in a profoundly discriminatory manner, a manner that ensures that the Transition period not only will not but *cannot* achieve an economically efficient outcome.

5.2 Lack of Consistency in the EMR's Recommendations

The PUO Position Paper describes four principal elements of the proposed reforms to the Reserve Capacity Mechanism, two of which are contradictory.

The PUO Position paper identifies two of the proposed reforms as:

> *"2. Transition arrangements for a period for the introduction of the auction that will involve maintaining the existing administered price mechanism but with a steeper pricing curve and a* ***differential treatment of demand side management****.*
>
> *3. Implementation of measures to* ***harmonise demand side management availabilit****y requirements with requirements for conventional generators,* ***for both the transitional arrangements and under the capacity auction****."*[21] *(emphasis added)*

[16] Spees, Newell and McIntyre ("The Brattle Group"); "Western Australia's Transition to a Competitive Capacity Auction", 29 January, 2016
[17] Brattle Group at 4
[18] Id at 3
[19] Brattle Group Letter at 1
[20] Brattle Group at 8
[21] Position paper on reforms to the Reserve Capacity Mechanism, PUO, 3 Dec 2015, pg. 1

Item two introduces the discriminatory treatment of DSM, while item three seeks to harmonise the availability requirements of DSM with conventional generation.

These items are, at best, contradictory, or at worst, an explicit attack by the PUO on a single form of capacity technology. If the EMR team accepts that DSM should be harmonised with conventional generation then there can be no basis for differential treatment. This is the gravest form of discrimination.

As discussed in Section 1.1, "capacity is capacity". In no other market in the world are different forms of capacity valued differently in the way proposed for the Transition period.

Differential valuation of capacity based on technology or extent of activity in the energy and/or ancillary service markets is unprecedented for the simple reason that all other markets have recognized that such discriminatory treatment prevents the achievement of economically efficient outcomes.

As Brattle Group notes:

> *"Discriminating between generation and demand response will distort investment and exit decisions away from the least-cost, economically-efficient outcomes. Generators will have incentive to reinvest in their capacity even when it is unneeded and less cost-effective than demand response[22]."*

EnerNOC supported the IMO's original rule change on harmonisation, and still supports its core principles. However, we cannot support a policy which treats DSM and generation differently from a pricing perspective, while another core aspect of the policy seeks to harmonise the two.

5.3 Proposed Baseline Will Destroy Ability for DSM to Participate

Technical changes to the way baselines are calculated have the potential to fundamentally change the amount and manner of DSM that can participate in electricity markets.

While it received less attention in the PUO Position Paper, the EMR has proposed a seemingly innocuous change to the manner in which DSM performance is measured. The new proposal would be devastating.

DSM performance is typically measured by comparing its actual metered load, when dispatched to reduce its load, with an estimate of what the customer's load would have been had it not been dispatched. This estimate is known as the "baseline" and is determined using well-accepted approaches developed by market operators over the last decade in markets around the world.

EnerNOC conducted a study of the impact of the proposed baseline change on its own large and diverse portfolio of customers in WA, then retained the leading international expert on DSM baselines, DNV GL (formerly KEMA), to perform an independent review of the results and opine the appropriateness of the new baseline.

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22 Brattle Group at ii

The final DNVGL results confirmed our analysis[23]. The Proposed CBL resulted in an average reduction of 59% when compared to the Current CBL.

The DNVGL Paper further notes that the "Proposed CBL is fundamentally disconnected from peak load conditions… This may imply a discrimination against the value of load management in the peak conditions when emergency events would most likely be called[24]."

Even though nothing would have changed with regard to actual customer operations, with a stroke of a pen, the PUO Position Paper would significantly reduce the creditable load reduction capability that could be provided by Western Australian customers. While the impacts on each customer would vary based on their usage characteristics, those most negatively impacted would be customers such as schools, hospitals and other non-industrial classes. Most of these customers would have their ability to participate reduced to nothing.

Notwithstanding the fact that the Transition period proposes to reduce payments to DSM providers by 85% and the obvious likelihood that much of the resource would quit the market as a result of the price reduction, it is apparent that the EMR team was not sufficiently certain that DSM would be eliminated. Just to be certain, they have proposed a baseline change that would eliminate the vast majority of whatever remains and prevent it from ever coming back.

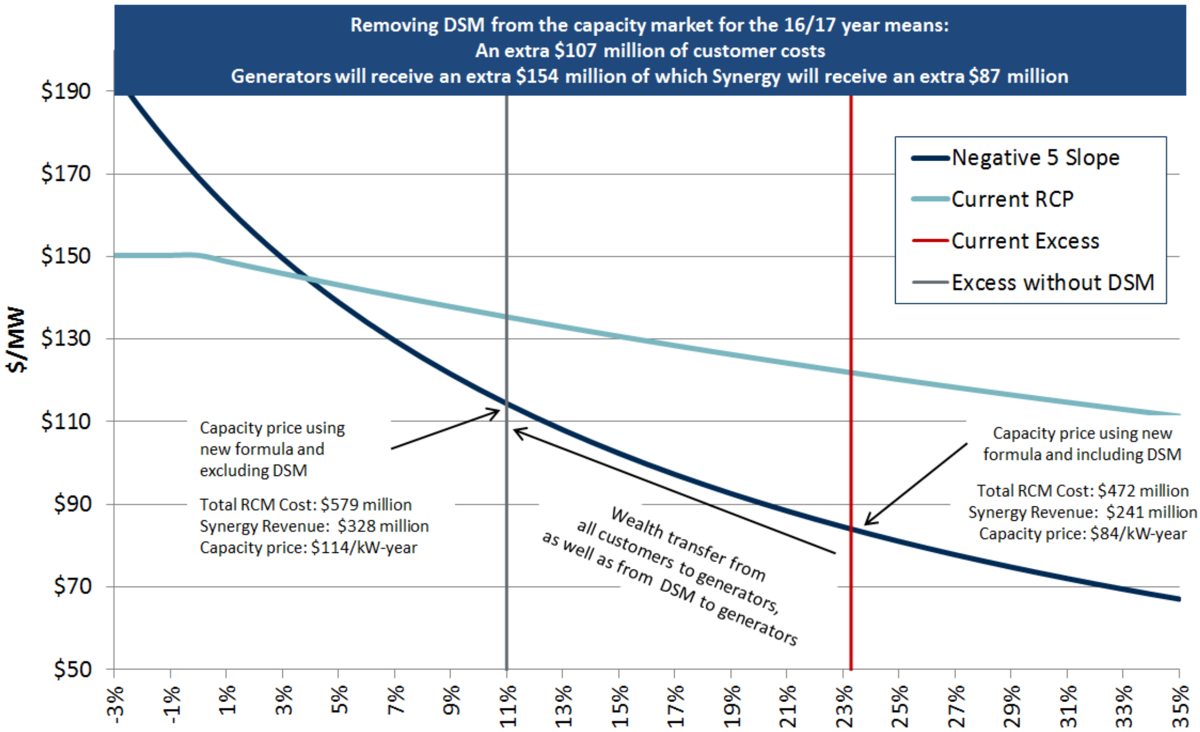
The price change proposal would do the work of causing all or virtually all DSM to exit the market. The baseline proposal would remove any residual DSM participation and ensure that DSM does not come back (at least until the baseline is reformed in the next crisis).

5.4 Forced Exit of DSM Will Increase Market Costs by More than $100 Million Annually

The perverse effect of government attempting to lower costs by picking winners would actually be a capacity price increase to a level which completely negates any savings that might be gained by removing DSM from the market, and increasing overall system costs by more than $100 million annually.

[23] DNV GL Paper at 2 and 3, Table 1 and Table 3

[24] Id at 5 and 6



The use of the term 'forced exit' is deliberate. On account of the discriminatory treatment, DSM would exit the market. This would distort investment and exit decisions away from the least-cost, economically-efficient outcome.

DSM is not the cause of the oversupply issue, yet the only substantial change the government is recommending for the Transition period is to effectively remove DSM from the market. This scapegoating of one technology in order to prop up the value of Synergy is radically bad policy that will harm consumers. Even worse, this is political expediency of the worst kind - it would prop up state-owned generation plant that is both inefficient and not required with costs borne by customers who have to pay for the system. Eliminating DSM in the name of reform removes the most effective (and principally, the only) tool that customers have to discipline pricing and ensure efficient market outcomes.

It is axiomatic in any efficient market, given the same demand for a given product, additional supply will lower the price and reduced supply will increase it. While the existing RCM is far from a model economic perfection, it does still exhibit this fundamental property, even under the proposed Transition Period arrangements. As existing capacity exits the market, the RCM price will increase.

EnerNOC conducted an analysis of the impact that removing DSM would have on the Reserve Capacity price. We then asked Brattle Group to review our analysis and confirm our findings. The results are contained in the attached letter (the "Brattle Group letter.")

Under the assumptions given, Brattle Group confirmed that removing DSM from the capacity mechanism, as proposed, would increase the price seen by other resources by $30/kW-year. Given the amount of capacity in the market subject to this new, higher price, payments to generators would increase by $154 million/year. This translates into a 23% increase in the RCM component of prices paid by WA consumers, or $107 million higher consumer costs than if DSM were retained. One might well ask what it is that WA consumers are purchasing for these higher electric costs. The answer would be flawed incentives likely to lead to (i) the perpetuation of otherwise uneconomic excess fossil-fuel capacity (mostly uneconomic coal-fired generation), and (ii) their own disenfranchisement as they are denied one of the few avenues they currently have to value their flexibility

6 A BETTER APPROACH: CAPACITY AUCTION

In EnerNOC's opinion, the proposed auction design is consistent with best practices from other global capacity markets.

While EnerNOC recognises that there are challenges faced with a quick transition to a capacity auction, the supporting submission from Brattle Group presents an alternate approach to satisfying this objective whilst supporting the PUO's objectives.

Fundamental to Brattle Group's proposal is the principle of technology neutrality. Notably, this principle is recognised by the PUO as a core tenet of the capacity auction. If this principle is accepted for the purposes of the auction, then we question why it is not so for the Transition Period.

6.1 Transition Period Will Compromise Move to a Competitive Auction

The implementation of the PUO's proposed transition mechanism would actually delay the retirement of inefficient capacity, rather than incentivising its retirement. Consumers would pay for this delay.

As noted in Section 5.1 the increase to the capacity price as a direct result of the Transition Period recommendations, creates an incentive to retain existing uneconomic capacity, and may also lead to the development of additional uneconomic capacity to prevent the trigger of an auction.

By its nature, an auction introduces an element of uncertainty to the capacity price outcome, and poses an element of risk to market participants. This risk could potentially distort generators' incentives to maintain and invest in their existing capacity in order to extend the Transition Period, as opposed to transitioning to a riskier auction.

In light of this, EnerNOC questions the true intent of moving toward an auction as the Transition Period would not achieve its stated aims of retirement and reduced incentive for the development of additional capacity.

6.2 Price Shock Will Occur in the Auction

The eventual introduction of a capacity auction would see DSM re-enter the market, causing exactly the kind of price shocks the EMR is trying to avoid.

As noted in Section 2, the introduction of emerging energy technologies may impact the market's capacity mix. This, coupled with the potential re-entry of demand response into a capacity auction[25],

[25] Assuming there are no impediments to its participation

would result in a major exogenous shock to the first auction and would destroy any steadying effects of a managed, yet discriminatory, transition.

7 ALTERNATIVE TRANSITION APPROACH

Brattle Group is recognised as the leading global expert on capacity market design.

Because so much of the EMR's proposal is misguided and blatantly out-of-step with global best practice, Brattle Group has conducted a review of the EMR's proposal. In the estimation of Brattle Group, the proposed Transition Period approach is not consistent with best practice, and will fail to meet the PUO's stated objectives, as a result of the following problems:

- *"Discriminating between generation and demand response will distort investment and exit decisions away from the least-cost, economically-efficient outcomes. Generators will have incentive to reinvest in their capacity even when it is unneeded and less cost-effective than demand response.*
- *The proposed static pricing schedule will maintain uneconomically high prices for a protracted period that may extend well beyond a decade before the auction is triggered. The mechanism will also produce two price shocks, one initially, and another when the auction is implemented. This adds uncertainty and instability to the market.*
- *The proposed outcomes-based trigger for moving to an auction further distorts generators' incentives to uneconomically maintain and invest in their capacity in order to extend the transition period with its rich pricing schedule".*

As a result, Brattle Group have developed its own recommendations for how to better achieve the PUO's stated objectives, which it has detailed in a separate submission. **EnerNOC fully supports Brattle Group's "PUO Transition Mechanism Proposal",** which includes the following key recommendations:

- ***A Level Playing Field for All Resource Types.*** *To achieve the most economically efficient resource retirement, retrofit, and reinvestment decisions, we propose to treat all resources on a level playing field with the same capacity prices paid to all resource types including demand response and generation.*
- ***Immediate (or Early) Introduction of Auctions.*** *We propose moving to an auction format immediately (or at least as soon as possible after a small number of years). This would maximize competition among different resource types, thus ensuring that the costliest resources exit the market first and that the lowest-cost resources are retained. Early auction introduction would also allow for steeper demand curves to be implemented sooner.*[26] *Earlier*

[26] "Conducting an auction with a very flat demand curve would yield very similar results to an administrative mechanism, however as the curve becomes steeper it becomes more important to use an auction rather than administrative payments. This is because with a very steep demand curve there is a greater uncertainty in what the auction-clearing or administrative payment price will be as small changes in system quantity can cause larger changes in price. Thus an administrative payment system with a steep demand curve would introduce large risks for suppliers that have to commit to selling capacity before they know the price. An auction solves this problem by allowing sellers to specify their offer price, reflecting the minimum payment they are willing to accept."

introduction of auctions will also provide an opportunity to refine the auction structure while supply is plentiful and prices will presumably remain relatively low.

- ***Flat Initial Demand Curve Similar to the PUO Proposal.*** *The initial demand curve would be relatively flat to mitigate the size of the initial shock, for example it could have the same shape as the final demand curve proposal, but with a right-stretched zero crossing point to make it flatter and have an expected price shock similar to the proposed transitional curve with a -5 slope.*
- ***Steepening Demand Curves Over Time.*** *The curve would then become steeper each year according to a pre-determined schedule until it equals the final demand curve after perhaps five or ten years. After the initial shock, this would result in gradually lower prices over time to levels reflective of the final auction design. A shorter transition period would allow for greater price reductions, lower customer costs, and fewer incentives for uneconomic supply-side (re-)investments. But the shorter period would also come at the expense of a more rapid decline in supplier revenues and less buffer against the "shock." Selecting an appropriate transition period would need to balance these competing interests.*
- ***A Fixed Timetable for Achieving the Final Design.*** *We also propose that this transition to the final demand curve would be pursued according to a fixed, pre-determined schedule. A fixed timeline will eliminate the incentive for generators to maintain excess capacity to delay the final auction. It would also reduce regulatory uncertainties and allow suppliers to offer their capacity based on more reliable long-term expectations of future prices and market design.* [27]"

We believe Brattle Group's proposal is consistent with proven global best practice for capacity markets, and we believe it is the surest path to achieving the PUO's stated objectives. The proposed approach would produce real savings for consumers and not simply wealth transfers from consumers and DSM providers to private and state-owned generators. It would promote robust competitive markets (rather than the heavy hand of government), and would promote investment in WA rather than deter it through increasing perceived sovereign risk.

8 THE RCM IS NOT THE MAIN PROBLEM: LET'S REFORM SYNERGY

In stark contrast to the assertions made in the PUO Position Paper, the main issues facing the Western Australian electricity system revolve around the state-owned gentailer, Synergy.

We know these issues are well understood by the EMR, given that Synergy's Chairman serves as a member of the EMR. Nevertheless, we feel it important to highlight these issues and to try and put them in context relative to the proposals in the PUO Position Paper.

As Phase 1 of the EMR demonstrated, when comparing utility cost structures, Synergy's costs are significantly higher than those of its Eastern States counterparts.

These high and inefficient costs are ultimately passed on directly to Western Australian households and businesses in the form of price increases and indirectly to taxpayers as a result of subsidies paid

[27] Brattle Group at 10

to try and keep prices down**. In total, it is our understanding that Synergy is subsidised to the tune of hundreds of millions of dollars each year[28].** There are a number of reasons for Synergy's inefficiencies, which we outline below.

8.1 Impact of Underwater Contracts

Following the blackouts in 2004, there was pressure on the Western Australian Government to ensure an adequate supply of electricity. This resulted in the state-owned retailer, Synergy, signing a number of long-term contracts for the purchase of electricity from new private sector generators to ensure adequate supply would be available to maintain system reliability. It is now apparent that these contracts must have been signed at prices far in excess of present-day wholesale prices, on a take-or-pay basis. The take-or-pay nature of the contracts has locked Synergy into unfavourable terms. These contracts persist to this day, with taxpayers bearing the costs of these unfavourable terms. The confidential nature of these contracts is a significant barrier to understanding the extent to which the terms are unfavourable, but there is no doubt they are significant.

8.2 High Costs Due to Synergy's Ageing and Inefficient Plant

At various points over the past sixty years, the State Government has had to choose the most efficient way to provide a reliable supply of electricity to the people of Western Australia. Inevitably, these considerations have had to be balanced against competing government spending priorities, such as the provision of essential services like healthcare, policing services and education. As a result, successive governments have made compromises between cost and reliability in the way the state's portfolio of electricity generation assets has been developed. Overwhelmingly, the largest compromise has been the refurbishment, rather than replacement, of ageing generation plant. Most recently, state-owned baseload power stations reaching the end of their useful lives have been refurbished rather than replaced. This has deferred upfront capital costs to taxpayers, but it has also left taxpayers relying on ageing plant that is far less efficient than the modern plant that could instead have been built by the private sector. By deciding to refurbish these plants, the government has essentially decided to keep the costs of electricity generation on Treasury balance sheets, precluding private-sector investment and risk-taking.

This has contributed to the government's net debt problems, increasing recurring expenditure on maintenance, labour, and other overhead costs. It has also deprived consumers of the opportunity to purchase electricity from newer, cheaper, more efficient plants and forced them to absorb the costs from older plants. It is likely that the book value of these older, refurbished state-owned plants is higher than their market value. This forces the government to carry costs that are higher than they otherwise could have had the decision been taken to retire the ageing plant. This is no doubt a difficult political decision, in that no owner – whether a state government or otherwise – wants to write off or realise a lesser value for the assets that it owns. However, failure to recognise the actual value of the assets consigns captive customers – those who are not contestable – to propping up government assets. This inefficient plant directly adds to Synergy's cost base, and therefore increases

[28] Electricity Market Review Discussion Paper, Electricity Market Review Steering Committee, 25 July 2014, pg 40 – "annual cost of supply subsidies were estimated by the ERA at $371 million in 2012-13 and are expected to rise in subsequent years. This does not include the additional subsidy costs associated with the Uniform Tariff Policy which is primarily aimed at equalising tariffs for non-SWIS customers."

the amount that customers, especially households without access to competition, have to pay for electricity.

8.3 The Effects of Government Ownership

The effects of inefficient plant and underwater power purchase agreements are exacerbated by the government's ongoing ownership of electric utilities. If the electricity industry were comprised solely of private businesses, government would not incur the costs associated with inefficient plant. If a private company had signed unfavourable long-term contracts, the holder of those contracts would either renegotiate or terminate the contracts, or go out of business. Government ownership of the utilities means none of these options have been available. The government's position was invidious. It could not allow its utility to go out of business, as would occur in the private sector, and political risks also impeded attempts to remedy the underwater contracts. As such, the taxpayer has been left to meet the shortfall through subsidies. This situation persists to the present day.

8.4 Lack of Competition Forces Customers to Pay Higher Costs

Due to its monopoly over the provision of electricity to the residential market and small businesses, Synergy's inefficiencies are borne by customers who have no recourse to lower their electricity costs. The utility has no economic incentive to make its operations more efficient, because it faces no competition. The costs of providing electricity can continue to rise (at least to the political or economic breaking point) because customers have no ability to choose a retailer that is more e-fficient.

8.5 Solving the Problem: Restructuring and Privatising Synergy

The Government has recognised the problems outlined above, but it has done little to alleviate them. While the Government has proposed to sell some discrete assets, it is disappointing that the Minister for Energy continues to rule out the sale or closure of hugely inefficient assets like the fifty year old Muja power station. As a result, Synergy continues to receive hundreds of millions of dollars in annual subsidies[29].

The root cause of these problems, and the associated subsidies, is government ownership. The only way to overcome them is to transfer the ownership of Synergy into private hands so that a privatised Synergy can properly respond to market signals without being impeded by political imperatives.

Splitting and privatising Synergy will not only end the ongoing need to prop up Synergy, but it will pave the way for further market reforms that cannot credibly succeed in the face of Synergy's (the government's) current dominant market power.

9 THE ADEQUACY AND INTENT OF CONSULTATION

The short consultation period is fundamentally inadequate given the controversial nature of these reforms, and is not in keeping with best practice policy development.

[29] Electricity Market Review Discussion Paper, Electricity Market Review Steering Committee, 25 July 2014, pg 40.

The RCM component of the EMR review was widely recognised by both industry and Government as being controversial and among the most difficult aspects of the reform to address.

In light of this, the 1 May 2016 target date for the commencement of the Transition Period is extremely short and does not provide sufficient opportunity to undertake adequate stakeholder consultation. The brevity of the consultation period questions the integrity of the policy making process and raises serious concerns that point to a there being a predetermined outcome[30].

In stark contrast to the PUO's RCM review, the National Electricity Rule making process contains four explicit stages to allay any similar concerns:

> *"Stage 1: Initial consideration of a request for the making of a rule*
>
> *Stage 2: Consultation on a proposed rule*
>
> *Stage 3: Draft rule determination (which may include a draft rule) and further consultation*
>
> *Stage 4: Final rule determination and if relevant, the making of an amending rule[31]"*

In addition to this process, the AEMC and AEMO often initiate multiple public forums that supplement the formal written process.

10 CONCLUSION

In summary, there are fatal flaws in the proposed transition plan which will cause the Electricity Market Review to fail.

The blatantly discriminatory treatment of DSM contravenes energy market best practice and violates the WEM's own Market Objectives, ensuring a blanket exit of DSM from the market which will negatively impact reliability.

Not only does such an approach disenfranchise over 300 Western Australian DSM providers that have invested in this market in good faith, but it will result in a $107 million increase in customer costs that will eventually have to be borne by consumers and taxpayers. This is an extraordinarily high price to pay for a policy failure that is foreseeable and preventable.

We urge the Electricity Market Review to investigate the alternatives we have outlined. They are backed by evidence from markets all over the world and have been developed by the world's most eminent energy economists. This is the surest path to achieving the Electricity Market Review's objectives.

30 The PUO's Information Paper includes a graphical timeline that highlights that actual drafts to the Market Rules will be made from December 2015 through February 2016. This further brings into question the integrity of the policy making process, and the ability to adequately incorporate stakeholder feedback into the final rules.

31 http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/Rule-making-process.

APPENDIX A: COMMENTS ON THE DISCUSSION QUESTIONS

The comments in this section do not contain the entirety of our response and should be regarded as complementary to the comments included in the body of the submission.

Section 3

Feedback on reform principles

As noted in the introduction to Section 6, a core principle omitted from the PUO Position Paper is technology neutrality. The proposed Transition Period unfortunately discriminates against DSM, which severely compromises the very objectives of the reform.

Feedback on reform objectives

EnerNOC questions the genuine intent of the stated objectives given the clear discrimination between generation and demand response that will distort investment and exit decisions away from the least-cost, economically efficient outcomes.

Further, this distinction is made without having demonstrated that DSM is less economic than generation.

Section 4

Proposed reform – introduction of the auction is to be triggered by a forecast of 5-6% of excess capacity in the year that the capacity price determined by the auction will have effect.

An alternative would be to establish a deadline for introduction of the capacity auction if it has not already been triggered.

Submissions providing feedback on these alternative options are encouraged.

The proposed outcomes-based trigger for implementing the auction will have the unintended effect of distorting the incentives for the exit and entry of capacity. The prospect of price uncertainty introduced under an auction scenario would certainly increase incentives to maintain existing capacity.

The proposed outcomes-based trigger (% of excess capacity) would compound the inefficiencies of the distorted investment signal noted in Section 5.

EnerNOC strongly recommends the implementation of the alternate transition approach presented by Brattle Group, and summarised in Section 7 of our submission.

In the absence of implementing this preferential approach, and in the hope of ever reaching a capacity auction, our preference from the two options presented in the PUO Position Paper is for the establishment of a firm deadline for the introduction of a capacity auction which is no later than 2020**.**

Section 5

Proposed reform – The Electricity Market Review proposes to implement a reserve capacity auction designed in accordance with the principles and proposals outlined in this chapter.

Submissions providing feedback on this recommended reform to the Reserve Capacity Mechanism are encouraged.

In EnerNOC's opinion, the proposed auction design is consistent with best practices from other global capacity markets.

As noted in Section 6, the foundational principle of technology neutrality is recognised by the PUO as a core tenet of the capacity auction. This should be extended to the Transition Period to ensure it adheres to global best practice.

Section 6

Proposed reform – Implement the proposed changes in Table 6.1.

Submissions providing feedback on this recommended reform to demand side management availability requirements are encouraged.

Harmonisation:
EnerNOC believes that DSM should provide the functional equivalent of peaking resources within the Western Australian and all other capacity markets. Based on the analysis presented in Section 1.2 of this paper, we believe that DSM already provides this functional equivalency, given that a) the amount of actual DSM capacity is at a similar level (less, actually) to the amount of "super-peaking" demand in the WEM (peak demand in the top 25 hours + 7.6% reliability reserve margin), and b) peak demand almost always occurs during the daily availability hours of DSM resources.

However, we acknowledge the discussions held within the Reserve Capacity Mechanism Working Group (RCMWG) surrounding concerns about current restrictions on DSM resources, especially those expressed by System Management at Western Power. We believe it is critical that System Management has full confidence in its ability to use DSM, and therefore we support the proposed approach.

While we do support the proposed approach, we do also want to note that harmonisation will likely result in a natural exit of the least flexible and available DSM resources. Based on experience in other markets that allow DSM resources to bid different amounts of capacity for peak periods (business days) vs. off-peak hours (nights and weekends), we would expect that the total amount of DSM capacity in the WEM would be reduced substantially as a result of changes to the DSM availability requirements. This is because a) most customers simply don't use as much electricity during off-peak hours, and b) many customers won't be able to justify the investment necessary to have staff available to respond to dispatch events during nights and weekends.

Finally, as noted in Section 5 of this paper, if the PUO accepts that demand response should be harmonised with conventional generation then there can be no defensible basis for differential pricing treatment.

Baseline:
The determination of appropriate baseline for various market constructs has been thoroughly investigated, and many international markets (both capacity and energy) provide best-practice baselines.

In 2011/12, all of the wholesale market operators in the US were required to develop baselines that would be sufficiently robust to permit DSM 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.[32]

Based on analysis of EnerNOC's DSM portfolio in WA, the proposed baseline methodology would reduce the level of DSM well beyond the 220MW estimate presented in the PUO paper. As detailed in Section 5.3, 83% of EnerNOC's portfolio will be arbitrarily discredited on account of the proposed baseline, even ignoring any price effects.

Further, the IRCR cap will result in an artificial limit on the ability of customers to receive value for the full amount of load reduction they are capable of providing, to the detriment of both participants and the system operator. This approach also hinders the ability to aggregate customer load.

EnerNOC would welcome the opportunity to discuss this matter in more detail with the Review team.

Real-time telemetry:
EnerNOC supports the real-time telemetry requirement, however, notes that the detailed telemetry requirements should be finalised at least 18 months prior to their proposed implementation, to allow sufficient time for an orderly and cost-effective implementation.

EnerNOC would also like to note that the telemetry specification should recognise that large-scale provision of demand response by aggregators will cover hundreds of individual sites. The requirement for real-time telemetry should be balanced against the cost of implementing a highly-specified solution at each site.

For example, in order for the provision of ancillary service by aggregations of much smaller facilities to become feasible, a simple, standardised approach is needed to telemetry. Rather than requiring high-resolution frequency data to be recorded for each under-frequency event, some reliance can be placed on type testing before a roll-out of more appropriate devices[33].

Proposed reform – Implement the dynamic refunds proposal developed by the Independent Market Operator.

Submissions providing feedback on this recommended reform for the adoption of dynamic refunds are encouraged.

[32] See, for example two studies characterised 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-analysisreport.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

[33] This is the current practice in the NZ, in which EnerNOC provides over 200MW of FCAS, from over 100 customer sites

Proposed reform - Implement the refunds recycling proposal developed by the Independent Market Operator with limited changes. Submissions providing feedback on this recommended reform adopting changes to capacity refund recycling arrangements are encouraged.

No comment

Proposed reform - Implement the generator availability proposal developed by the Independent Market Operator with minimal changes. Submissions providing feedback on this recommended reform to generator availability are encouraged.

No comment

Section 7

Proposed reform – A single slope of the capacity pricing curve of negative 5 for the duration of transition period. Submissions providing feedback on this proposed reform to the capacity price adjustment formula are encouraged.

Please refer to the supporting submission prepared by Brattle Group.

Proposed reform – To increase the capacity price cap to 110 per cent of the Maximum Reserve Capacity Price. Submissions providing feedback on this proposed reform to the capacity price cap are encouraged.

Please refer to the supporting submission prepared by Brattle Group.

Proposed reform - capacity payments made to demand side management facilities should be calculated in the following manner during the transition period:

* Demand side management resources to receive a lower capacity price than supply-side resources and a higher energy payment (when dispatched for more hours than estimated).
* Capacity payments made to demand side management resources though the transition period to be based on an estimate of the expected hours of dispatch plus a margin for the costs associated with running a demand side program and also testing costs. Submissions providing feedback on this proposed reform to the treatment of demand side management resources are encouraged.

As noted throughout this submission, the specific treatment of DSM proposed in the Transition Period is discriminatory, does not conform with best practice policy, would result in distorted market investment signals, would result in an increase to total consumer cost, and would severely hamper any transition to a capacity auction.

APPENDIX B: DNVGL ANALYSIS OF PROPOSED DSM BASELINE

Memo to: Aaron Breidenbaugh, EnerNOC, Inc
Copied: Curt Puckett DNV GL
Will Gifford DNVGL

From: Tim Hennessy, DNV GL
Date: January 28 2016

Analysis of Proposed Capacity Baseline Methodology for the Western Australian Wholesale Electricity Market

1 INTRODUCTION

The "Position Paper on Reforms to the Reserve Capacity Mechanism" proposes a change in baseline methods for the Western Australian Wholesale Electricity Market. The proposed change is from a static baseline (customer base line, or "CBL") based on the median of 32 half-hourly intervals comprised of the peak eight half-hour periods during the four hot season months ("Current CBL") to the 5th percentile of the top 200 load hours ("Proposed CBL"). This memo recapitulates the analysis performed to quantify the effects of such a change.

It was expected the change from the current to the proposed CBL would lower the CBL value: the current baseline is based on the 16th peak-like half-hour interval, as opposed to the 390th peak-like half-hour interval in the Proposed CBL. Lowering the CBL has two effects. First, it increases the number of potential event days where the DR participant would be required to reduce load, just to get to CBL (i.e., the zero-performance level). For weather sensitive resources, the load reduction required to get to the CBL level would be more on hotter days than on more mild days. Secondly and related to the first point, in order to demonstrate that the commitment was fulfilled in an emergency event, the DR participant would have to reduce load to a lower level to be recognized as capacity resources. Since only reduction below the baseline is recognized as demand response capacity, the demands above the baseline can be thought of as unrecognized or uncompensated capacity.

For this analysis, system and participant data from 2013 to 2015 was examined. The data allowed for two baselines for each participant to be calculated relating to the 2013/2014 and 2014/2015 capacity years.

2 ANALYSIS

The initial analysis examined a hypothetical participant using System Balancing load data.

It is important to note, that there are a number of critical distinctions in assessing the impact of the Proposed CBL when using aggregate System data (as the hypothetical customer) as opposed to using an actual customer's load.

1. System load is an aggregation of thousands of diverse residential and business loads. The aggregation benefit results in reduced load variability – minimizing the impact of the Proposed CBL;
2. The Proposed CBL does not allow for the same aggregation benefit due to the IRCR cap.
3. The peak 200 hours of the system load are 100% correlated to its own peak periods[1]. For an actual customer, their own peak will not be 100% correlated to the System peak. Therefore, the System load is not representative of the likely impact on WA businesses. This difference is highlighted in Table 1 and Table 3 below.

Table 1 shows a comparison calculated CBL, number of hours that the participant operated above this level ("available contribution half hours"), and the amount of unrecognized capacity associated with those hours. Using the current CBL methodology, the CBL would decrease in each of the years, about 10%. This hypothetical participant would almost triple the number of hours that their loads would be above the CBL (i.e., be able to contribute to capacity if an event was called. The amount of demand it would need to decrease during these hours before reaching the CBL level increases five times. This is consistent with the expectation of the impact of the change in CBL methodology.

Table 1 Comparison of Current and Proposed CBLs for a Hypothetical Participant (i.e., single customer, based on System Load)

Period	Current	Proposed	Change
	Average CBL (MW)		
2013-2014	3,513	3,132	-11%
2014-2015	3,370	3,061	-9%
Average	*3,442*	*3,097*	*-10%*
	Available Contribution Half-Hours		
2013-2014	47	325	591%
2014-2015	127	350	176%
Average	*87*	*338*	*288%*
	Unrecognized Energy (MWh)		
2013-2014	2,527	31,935	1164%
2014-2015	10,335	45,774	343%
Average	*6,431*	*38,855*	*504%*

[1] This is equivalent to the 97.8th percentile of the system load.= 1- (190/8760)

Next, actual participants were examined. Table 2 shows the number of participant included in the analysis by year. This table shows that 99% of the participants will have decreased capacity under the proposed CBL method.

Table 2 Summary of Participants in the Analysis

Period	Number	Proposed CBL less than Current CBL
2013-2014	464	459
2014-2015	432	428
Average	*448*	*444*

Table 3 Comparison of Current and Proposed CBLs for Analysis Participants

Period	Current	Proposed	Change
	Average CBL (kW)		
2013-2014	695	295	-58%
2014-2015	911	367	-60%
Average	*803*	*331*	*-59%*
	Average Available Contribution Half-Hours		
2013-2014	256	1,067	269%
2014-2015	282	1,107	313%
Average	*269*	*1,087*	*288%*
	Average Unrecognized Energy (kWh)		
2013-2014	137	402	191%
2014-2015	145	513	251%
Average	*141*	*458*	*221%*

Table 3 shows a comparison of the two methodologies on the participant CBLs. This table shows that under the proposed methodology, the average CBL declines nearly 60%. The change in CBL definition (the proposed method 5th percentile of the top 200 hours vs. the current CBL based on the median of the 16 peak hours) allowed four times more half-hour intervals to be above the Proposed CBL.

3 OTHER INDEPENDENT SYSTEM OPERATOR CBL METHODS

3.1 NYISO

When considering a change in their CBL methodology, the New York Independent System Operator (NYISO) retained DNV GL in 2013 to examined alternative baseline methodologies for the Special Case Resource (SCR) program. This analysis examined the NYISO ACL methodology and alternative methods of Customer Baseline Load (CBL) approaches to determine their applicability to the SCR capacity market program. This analysis involved comparing existing capacity baselines with variations under consideration, including different ranges of hours, Capability Period and Monthly ACLs[2]. While some of the baselines were similar structurally to the proposed CBL method (distribution point of top x hours), none considered a 5th percentile of a distribution, and none considered as many hours as the proposed CBL method. This study allowed NYISO to quantitatively determine the most appropriate ACL, as well as capability period on which it is based.

3.2 PJM

Electric Distribution Companies (EDCs) in the PJM system have a capacity obligation, based on their system contribution to the total PJM system load during the previous year 5 coincident peak (5CP) hours. The capacity obligation ultimately flows down to end use customers in the form of an explicit capacity charge, or is incorporated into energy supply portions of billing statements. The cost to the end use customer is often based on the portion of the overall EDC kW attributed to the customer's rate class, as measured using a load research sample stratified by EDC rate class, but the exact methodology for determining this cost share is selected by the EDC subject to any prescribed methods by the applicable state commission.

The nominated load value of a CSP load management resource can be calculated using one of two formulas:

1. Firm Service Level (FSL)
2. Guaranteed Load Drop (GLD)

Under FSL, the nominated value is equal to the applicable PLC for the resource, minus the product of a CSP-chosen Firm Load level (FL) and the EDC loss factor. The PLC in this computation is a static value, determined by the EDC, not by the CSP (unless the EDC is bidding the load management resource directly). The FL represents the kW level that the CSP commits to reduce the aggregate registered load to during a PJM-initiated emergency event, or be subject to non-performance penalties. The specified FL reflects the risk tolerance of the CSP: the lower the FL, the higher the nominated value, and

[2] Monthly ACL is allows the CBL to change month by month, rather than have one annual value. For example, the July ACL would be based on the previous July loads.

the higher the nominated value, the higher the auction revenue. However, the lower the FL the higher the chance of non-compliance and the higher the chance that performance penalties will be assessed.

Under GLD, the nominated value is equal to the CSP-specified kW commitment for load reduction, multiplied by the EDC loss factor. Compliance under GLD is determined by computing one of the permissible Customer Baseline (CBL) formulas to estimate the counterfactual reference load during a PJM-initiated emergency event. If the load reduction, measured as the reduction of the actual event load for the resource from its CBL, is above the commitment level, and the actual event load subtracted from the PLC is above the commitment level, the resource is in compliance. Otherwise a non-performance penalty is assessed.

For most load management resources, FSL is the clear choice because it is easier to demonstrate compliance than under GLD. Accordingly, the comments below correspond to FSL, rather than GLD.

This framework for determining the nominated value for load management resources is consistent with the framework for determining the capacity obligation for EDCs. Suppose that all customers associated with an EDC had interval metering, so that an individualized PLC could be computed unique to each customer based on its usage during the 5CP hours. The sum of those PLCs across all customers in the EDC will be equivalent to the PLC for the entire EDC, which is directly correlated with its capacity obligation. For customers that are part of a load management program, their kW reduction commitment therefore represents a direct proportional reduction in the capacity obligation for the EDC in the upcoming electricity delivery year.

The nominated value approach for load management in the PJM capacity auction can result in compliance tests which are incongruent with a robust impact evaluation, when DR is dispatched on days when the reference load baseline is significantly different than the static PLC (i.e., on a non-peak load day), or when the year-to-year change in the DR customer load on the 5CP days is significant. However, we find that the PJM approach is reasonable one for determining nominated value of load management resources because it is fundamentally consistent with established approaches for allocating the cost for procuring capacity down to the customers.

The proposed approach for computing nominated value in the Western Australia capacity market is similar structurally to the PJM FSL methodology, but instead of anchoring the reference load to an assumed peak load level as PJM does using the 5CP hours, the Proposed CBL uses the fifth percentile of the top 200 load hours. As compared to the PJM approach the Proposed CBL is fundamentally disconnected from peak load conditions. This disconnect may be a result of methodology for load management nominated values being inconsistent with the methodology for determining the EDC shares of capacity needed maintain resource adequacy for the system. This may imply a discrimination against the value of load management in the peak conditions when emergency events would most likely be called.

4 CONCLUSIONS

This analysis provides five conclusions:

- The proposed CBL method will drastically reduce the participants CBL by nearly 60%.
- The proposed CBL method increases the number of hours that participants load is above the CBL.
- The proposed CBL method dramatically increases the amount of demand a participant will need to be reduced before providing capacity below the CBL.
- As compared to the PJM and NYISO approaches the proposed CBL is disconnected to peak load conditions, which will reduce the ability of load management (particularly weather sensitive) to provide value during the more likely times of emergency events, and discriminate against the value of load management during these periods.
- Prior to adoption of a new CBL methodology, the performance of the proposed CBL method, as well as the current and alternative CBL methods should be quantified and compared to determine the most applicable and reliable CBL for Western Australia

January 15, 2016

Mr. Richard Wilson
Mr. Mottel Gestetner
Mr. Aaron Breidenbaugh
EnerNOC Pty Ltd.
359 Oxford Street
Mount Hawthorn
Perth, WA 6016
Australia

Re: Validating EnerNOC Calculations of Customer Cost Impacts under the Proposed Western Australia Transitional Capacity Mechanism

Dear Sirs:

We understand that your company EnerNOC is concerned about the treatment of demand response (DR) resources under the Public Utility Office's (PUO's) proposed transitional arrangement as described in the PUO's *Position Paper on Reforms to the Reserve Capacity Mechanism*. As part of your evaluation of the impacts of this transitional arrangement, you have made a series of calculations regarding the customer costs and other impacts of segregating DR from traditional generation under the transitional Reserve Capacity Mechanism (RCM) and paying it a lower price.

You have asked us to independently validate your calculations, which are restated in bold, and our response follows each point:

1. **If DR is segregated out, the price paid to the remaining RCM resources would be approximately $30/kW-year higher than if DR were included, assuming all DR would exit if paid the lower DR price and assuming and the amount of generation exiting would be unaffected by the $30/kW-year difference.**

   We confirm that this calculation is accurate, given the stated assumptions about supplier responses.[1]

2. **Excluding DR from the RCM transition mechanism would increase the RCM component of monthly bills by 23% for customers fully exposed to wholesale prices, given the same**

[1] We were not asked to assess the assumptions themselves. If, in fact, some DR did not exit under the proposed transition plan, or some generation would exit in response to the lower prices with DR un-segregated, then the price impact would be less than $30/kW-year.

assumptions as above. This would amount to $107 million higher annual customer costs if all customers were exposed (or less, to the extent that they are hedged against such exposure).

We confirm that this calculation is accurate, given the stated assumptions.

3. **Under the same assumptions as above, excluding DR from the RCM transition mechanism would increase RCM payments to generators by $154M million per year.**

   We confirm that this calculation is accurate, given the stated assumptions.

Sincerely,

Kathleen Spees	Samuel A. Newell	Colin McIntyre
Principal	Principal	Research Analyst