Major Energy Users Inc.

Australian Energy Markets Commission

National Electricity Amendment (Non-scheduled generation and load in central dispatch) Rule 2016

Reference ERC0203

CONSULTATIONPAPER

Submission by

The Major Energy Users Inc

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The content and conclusions reached in this submission are entirely the work of the MEU and its consultants.

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1. Introduction

The Major Energy Users Inc (MEU) welcomes the opportunity to provide its views on the AEMC consultation paper addressing a proposed rule changes from Snowy Hydro and Engie which seek to have large electricity users bid into the spot market (Snowy) and requiring non-scheduled generation to comply with the dispatch rules (Engie).

The MEU has already provided its views on the Snowy proposal (see response sent December 2015) and many of the views expressed in that response are applicable to the additional rule change proposed by Engie. Recognising this, the MEU does not want to reiterate those comments and expects that the AEMC will carry those MEU comments forward into this consultation round.

1.1 About the MEU

The Major Energy Users Inc (MEU) represents the interests of large energy consumers operating in the NEM and in other jurisdictions. The MEU comprises some 30 major energy using companies in NSW, Victoria, SA, WA, NT, Tasmania and Queensland.

Of particular note, the MEU members include companies that have operated in the spot market with load shedding when electricity prices are high as well as companies that have implemented their own generation as part of their operations. These features provide MEU with intimate knowledge of the reasons behind decisions to enter the spot market and implement self generation – this knowledge also includes a sound understanding of the costs to implement these decisions

MEU members are very concerned about the cost, reliability, quality and long term security of their energy supplies and therefore the MEU comments in this submission are made in full knowledge of the need for managing the tensions between these separate aspects of energy supplies.

1.2 The difference between load and supply

As noted in its earlier submission to the Snowy proposal, the MEU highlighted a number of critical aspects with which the analysis of the Snowy proposal should be assessed:

- Generators operate just in the electricity market whereas end users operate in many markets, with electricity supply being a part (often just a small part) of their total input cost structure. This limits the focus of

users have towards the electricity spot market whereas for generators it is a major focus.

- Electricity is just one of the inputs users have to manage in order to be competitive
- While the price of electricity impacts those users operating in the spot market, it has little impact on the majority of users who operate under retail contracts
- Users' loads vary significantly on a daily, weekly, monthly and annual basis and these variations are driven by other aspects than just the price of electricity
- Users' demands for electricity are unpredictable and frequent whereas generators can be relatively precise as to when and how much they will supply to the market
- Some users load shed because of high spot prices, but others do so because their aggregator, retailer or network calls for load shedding in response to a price arrangement for the services they provide, but the most common reason for users reducing their demand is for operational reasons
- Users that have established an ability to operate safely in the spot market, have incurred considerable set up costs and incur significant continuing costs to continue the practice
- The frequency of market variations which would benefit from more accurate demand scheduling is modest when examining the totality of market movements. This implies that the benefits of the proposals will only have an impact on the market infrequently whereas the costs users incur will be continuous

The proponents have articulated that quantification of the benefits of their proposed rule changes is difficult to develop and therefore to provide an assessment against the costs is almost impossible. Snowy commented that on a qualitative basis, its rule change would improve:

- Confidence in pre-dispatch prices
- Reserve forecasting
- Management of the dispatch process
- Pricing of financial contracts
- Overall transparency in the NEM

Engie makes observations that their proposed changes would deliver similar benefits but that quantification of them is challenging.

The MEU can see that, at a theoretical level, such enhancements might provide a benefit to the electricity market, but there is considerable doubt as to the extent of the benefit to the market of such enhancements. In contrast, the costs can be quantified in considerable detail and will impact a large number of

parties that so far have not had to get involved in the market to the extent that the proposals will cause.

The MEU notes that the AEMC has, in previous rule change proposals, discussed the concept of "workable competition". The import of this concept is that, according to the AEMC[1],

> "…a market that is considered to be workably competitive need not have reached a state of perfect competition."

This observation implies that in attempting to create a perfectly competitive market, there are costs and other impacts which more than offset the benefits of the supposed increased competition. The MEU points out that the AEMC has already determined that the NEM exhibits “workable competition”[2].

The MEU points out that the AEMC has already accepted that some anti-competitive activities by generators (such as the economic withdrawal of capacity and bidding of ramp rates to reduce competition) are acceptable even though they result in the less than efficient performance of the NEM. Both Snowy and Engie were supportive of the AEMC positions on these generator activities yet seek to argue that their rule change proposals, which will impose significant costs of users and small generators, will provide significantly improved performance of the NEM. When examined in this way, it is clear that both Snowy and Engie are self serving in the extreme!

It is obvious that a number of the benefits claimed by the proponents are those that would (and should if they were needed) have been identified by AEMO as providing a benefit to the market, yet the MEU is not aware of any concerns raised by AEMO about these issues to the extent it has concerns about the effectiveness of the market. As AEMO has not previously raised these aspects as concerns, then it is apparent that AEMO does not consider the benefits that would be delivered from such changes would be significant. On this basis, the MEU questions the benefits to the market asserted by Snowy and Engie.

Users and small generators are price takers in the electricity market (recognising it is an ex post market) and the spot price is consistently set by large generators. It would be inequitable if users and small generators were to incur increased costs and risks if the benefit is small and would go to large generators as they are the prime providers of electricity into the market.

As stated in the MEU response to the Snowy Consultation Paper, the MEU does not consider that large loads should be required to bid their demand into

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[1] See for example, AEMC consultation paper, National Electricity Amendment (Potential Generator Market Power in the NEM) 14 April 2011, note 33 page 23

[2] See for example, in the AEMC determination on the MEU rule change proposal seeking to prevent “economic withdrawal” of generation capacity

the market, and neither does it consider that small generators should have to do so either.

1.3 The impact of >5MW generation and load on the market

Engie comments that the increasing numbers (and resultant volume from) of non-scheduled generation is distorting the NEM operation. In theory the MEU agrees that increased amounts of non-scheduled generation do present a challenge to the optimum operation of the NEM but equally the MEU considers the overall impact is small.

What is absent from the Engie assessment is any quantification of the numbers of non-scheduled generation plants and the extent to which they operate. As it stands, AEMO has a record of all generation >5 MW so it would be valuable to assess the actual output of these non-scheduled generators recognising that many have minimal impact the market because they dispatch less than 20 GWh in a year (ie an average maximum output of just over 2 MW when compared to the NEM which averages over 21000MW - ie 0.01% and just 0.2% of the Tasmanian market – the smallest regional market). Such miniscule movements are negligible when seen in terms of actual movements that occur every dispatch trading period where swings of over 1000 MW in the NEM (and even up to 100 MW in Tasmania) occur across a trading period.

The MEU points out that most small generation plants (> 5 MW) are installed to either assist in greenhouse gas reduction (eg biomass fuelled) or as an adjunct to larger energy using facilities (eg cogeneration). In practice, most small generators are not to provide electricity for commercial purposes (as do the large generators) but are used to contribute to greenhouse gas reductions, production cost reduction and/or to increase thermal efficiency of manufacturing processes. Because of this, most small generators operate continuously and so there is little variation on demand caused by the dispatch of these generators.

The Engie rule change proposal is based on the assumption that these small generators are used in the same manner as commercial (large) generators whose prime purpose is to generate revenue from the supply of electricity into the NEM. In practice, they operate as an adjunct to other drivers and not the electricity market. Accordingly their outputs are not controlled by the market but to meet other needs.

The MEU considers that as part of its assessment of the proposals, the AEMC needs to access the data from AEMO on all generation plant that has been either registered and is non-scheduled or >5 MW but exempt from registration and:

1. Identify if, in aggregate, the numbers and size of the small generators is sufficient to warrant the imposition of the new dispatch requirements, and
2. Examine the operational approach used by each generator to identify if, in aggregate, they are likely to vary their output as a result of market conditions.

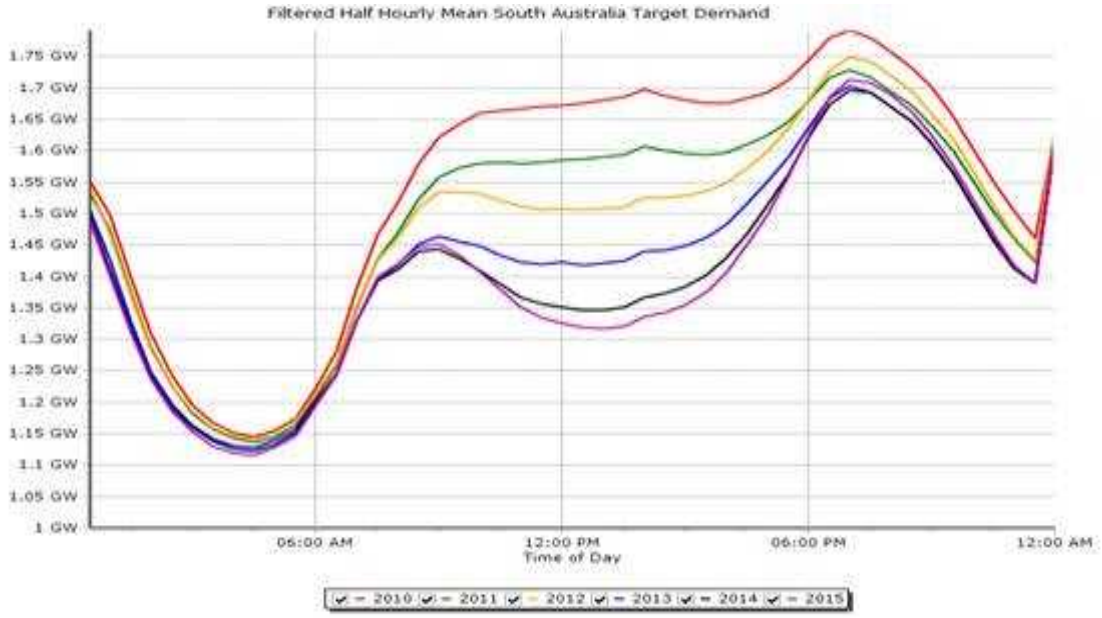
From this information, AEMC can assess the real impact of the small generation and whether the operational characteristics of this class of generation would be likely to vary their output significantly in response to market changes. The MEU contends that the large majority of small generation and demand movements by large users do not significantly impact the prices and demand forecasts by AEMO and so lead to a significant change in biding patterns by large generators.

The MEU also points out that there is an acceptance that the long run cost of a generator increases inversely with the size of a generator. If small generators were causing an impact to the forecast dispatch through varying their output in response to the market conditions, there would be seen much more price volatility as they are dispatched as they consistently would have to bid much higher prices than the larger generators in order to cover their costs. While there is price variation in the market, this price variation is so modest, it is obvious that for almost all of the time this variation reflects an outcome that is inconsistent with a view that smaller generators are causing the forecasts to be significantly in error.

It would appear that, on a high level qualitative assessment, it is unlikely that the dispatch pattern of smaller generators and load shedding by large users impacts the market as much as is implied by the Snowy and Engie assertions. It would therefore be inappropriate to impose a blanket requirement for all generation and all users >5 MW to have to be involved in the AEMO dispatch process and that the existing approach provides sufficient clarity to deliver a workable market without incurring the significant costs that the rule change requirements would impose.

1.4 Other impacts on the market

As a counterpoint to the above, NEM data shows that the impact of the large numbers of micro generators (specifically rooftop solar PV) in aggregate have a massive impact on the NEM, and one certainly with a greater impact than small generators and load shedding users. The following chart shows the annual average daily demand shape in SA region for the last six years.



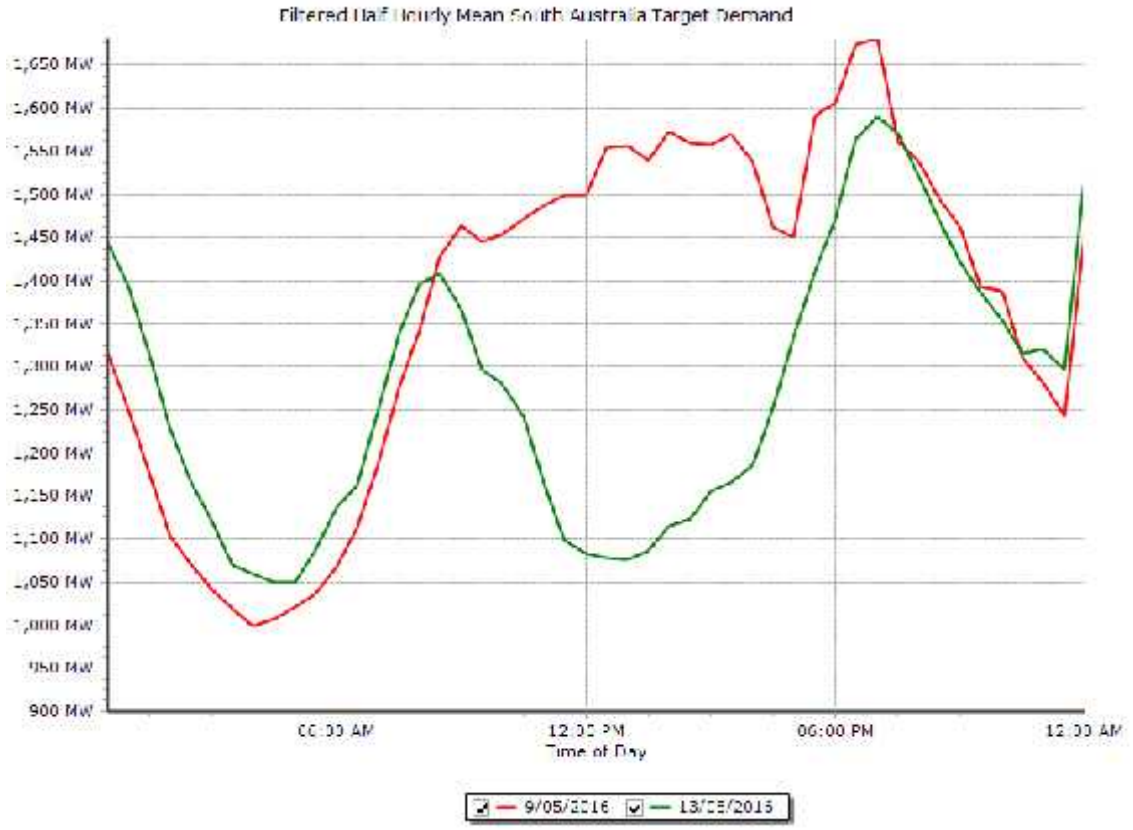
The chart shows the increasing impact of roof top solar PV generation changing the pattern for supply into the SA market. It highlights that the rooftop solar PV impacts especially in the middle of the day. Before the growth in rooftop solar PV, demand in the middle of the day was essentially flat before increasing to a peak early evening. As the growth in PV has occurred, there is a distinct "hollowing out" or "sag" in demand from the late morning to mid afternoon[3].

The impact has been an annual average change in midday demand of about 300 MW demand reduction occurring in the middle of the day over each of the six years examined but on some days the midday demand dip caused by rooftop solar PV is greater and on others, it is non-existent.

All of the other mainland regions[4] exhibit the same trend as the SA region although not yet as clearly.

The following chart shows the variation of demand in the SA region on Monday 9 May 2016 and Friday 13 May 2016.

[3] AEMO also makes this observation in its report on 2015 NEFR (minimum demand data - SA)
[4] Tasmania has a totally different load profile which reflects its unique circumstances



While the morning and evening peaks in demand are similar on both days, the difference of demand in the middle of the day is over 450 MW and this is primarily due to different weather patterns and the amount of roof top PV solar generation that results. This daily variation is consistent with the AEMO 2015 NEFR (page 2) which comments that in 2014/15:

> "[at] this time, [FY 2014/15] rooftop PV output was 445 MW."

AEMO goes on to say:

> "Based on the continued uptake of rooftop PV and its contribution to supply, by 2023–24, rooftop PV is expected to offset 100% of demand generated from the grid."

This additional comment implies that the impact of micro generation will become even greater in the near to medium term.

Even in 2016, micro generation is probably creating a greater impact on demand than small generation and demand side load shedding. If this variation can occur with the multiplicity of micro generators (which will not be captured by the proposed changes) then it is clear that the benefit from attempting to include small generation >5 MW and load >5 MW will be modest at best and insignificant compared to the variation in demand that micro generation is and will increasingly create in the market.

1.5 Cost impacts of the proposal

Engie provides some costs that it considers would apply to the various options for the rule changes it proposes. The MEU considers that the Engie costs are greatly understated when compared to the costs incurred by end users that have established an ability to be involved in the spot market.

For example, to prepare for spot price exposure and establish the tools required to manage the risk involves many 10s of thousands of dollars so a decision to take spot price exposure is not taken lightly when considering the costs. This assessment is supported by the observation that in proportion very few end users have taken exposure to the spot market due to the costs and risks involved.

It is apparent from the costs included in table 5.1 that the Engie assessment of costs is based on an assumption that the demand of the end user is constant and that the associated generator output would be constant too. If this were true, then the data input to AEMO would be the same and therefore the output data for submission to AEMO could be easily provided as a single number over time[5].

In practice, load varies continuously as does the output of a small generator.

For example, a common use for a small generator is for cogeneration purposes integrated into a manufacturing operation. As pointed out in the response to the Snowy proposal, electricity demand of a manufacturing operation varies continuously. The MEU points out that the output of a generator (especially a GT generator) also varies significantly with ambient conditions and with the demand for the steam it generates.

This means that under the Snowy and Engie proposals, continuous forecasting of demand within a facility will be required and the person responsible for providing the demand data to AEMO would have to receive input from each production line in the facility and aggregate this. Then the operational requirements for the cogeneration plant have to be identified[6] and normalised for the weather conditions. The combined site demand data then has to be relayed to AEMO.

[5] If this were the case, then there would be no need for the Engie or Snowy proposals as there would be no demand variation over time!

[6] For cogeneration plant both the steam needs and the electricity requirements have to be balanced, with stream requirements being the main driver as unneeded steam cannot be stored and wasting it is both costly and generates significant noise pollution.

The MEU points out that an operator costs some $100,000 per year and as the requirement to provide input to AEMO is continuous, there will be a need to employ a five shift roster for the purpose. The $37,000 proposed by Engie for option 1 continuing costs assumes that only 4 minutes of each hour of one person's time would be required to collect and collate the demand information from each production line and the generation facility for relaying onto AEMO the net demand. In practice, the MEU considers that as this is not a task that could easily be allocated to one of the production staff (which is what occurs when the decision is made to load shed in accordance with established protocols) so there would have to be a specific person dedicated to the task for providing the AEMO data.

While the Engie proposal seeks only information from the small generation plant, the small generator would probably bid its price at the market floor so that it would be dispatched by AEMO. This then introduces a further concern that if the regional demand is low and there is more generation plant being dispatched than required for the region, the small generator might not be dispatched by AEMO. Such a decision by AEMO would have a significant impact on production at the facility because if the generation plant is for cogeneration this impacts the production facility balance – why should an AEMO decision be able to impact the end user's other markets?

However, the Snowy proposal seeks for the end user to not only advise its demand (the Engie proposal) but also to price its demand as if it were a generator. This considerably increases the time requirement of the person charged with managing the AEMO interface as that person also has to identify what the conditions will be for production, but what production lines within the facility will be load shed and at what price. This changes considerably the dynamic for making a decision to load shed.

1.6 What is missing is an essential assessment of buyer's rights

As the MEU commented in its response to the Snowy proposal, both it and the Engie proposal are equivalent to using a sledgehammer to crack a nut.

The market structure is designed to provide a basis for dispatching generators in merit order of their pricing approaches – it is not designed (nor should it) be a mechanism for consumers to have to bid their decision not to buy or for small generators to have to incur significant costs so that there might be a small benefit (if any) through making it easier for large generators to operate in a market they have decided to enter, in full knowledge of its strengths and weaknesses and knowing that the market seems to work reasonably well for the large majority of the time.

1.7 Conclusions

In its decision not to make a rule change to limit the ability of large generators to garner a benefit through economic withdrawal of capacity, the AEMC considered that market imperfections should be permitted unless the outcome caused the average annual spot market price to exceed the long rum marginal cost for a new entrant to the market. This meant that the benefit from addressing the market imperfection[7] had to be significantly greater than the detriment of implementing the rule change[8]. What concerns the MEU is that while there might be a theoretical qualitative benefit from the proposed rule changes the quantifiable benefit is small, if any, and the costs significant.

Fundamentally, the issues raised by Snowy and Engie are about the accuracy of the AEMO forecasts on which the large generators base their bids for price and volume of dispatch. If AEMO recognises that there are other aspects than just spot price that will vary the demand at any particular time, then the forecasts will be as accurate as can be made. This other aspects are:

- End users will not load deliberately shed except when the spot price is very high although demand varies considerably even when the spot price is not high
- Small generators are unlikely to vary their dispatch even though the spot price might be very high (or very low) as there are other aspects that drive the decision to operate (or not) that are unrelated to the spot price
- Demand varies significantly even when the spot price is at levels where end users do not load shed or small generators can afford to generate (eg between $20/MWh and $100/MWh), so the proposed rule changes would not provide a benefit to the market
- The impact of micro-generation is much greater than load shedding or the dispatch of small generators

Overall, the MEU considers that the AEMO forecasts of price and demand will not be refined to the extent assumed by the rule change proposals by their implementation when considering the variation that already occurs in the market at times when end users and small generators do not seek to vary their import and/or export decisions.

In addition, the costs on end users and operators of small generators to comply with the requirements implicit in the proposed rule changes are much greater by far than the costs suggested by Engie.

[7] In terms of cost to consumers
[8] In terms of the direct cost and the indirect cost of dis-incentivising new generation investment

2. Responses to AEMC questions

The MEU provides the following responses to the specific questions raised in the Consultation Paper. The MEU has endeavoured to keep its answers as concise as possible and refers to the commentary in the preceding sections to amplify its reasoning.

	Description	MEU observations
1	**1. To what extent do non-scheduled controllable generators with nameplate ratings between 5MW and 30MW cause inaccuracies in the dispatch demand forecast and to what extent do such inaccuracies result in inefficiencies in the dispatch process through:** **(a) the spot price being set at a level which does not reflect the actual supply and demand conditions in the market?** **(b) the cost of scheduled generation meeting actual demand not being minimised?** **(c) increases to the cost of supply through higher FCAS costs in the long run?**	See above comments. The MEU considers that the impact of <30MW>5MW generation is minimal when considering the manner in which they operate
	2. If there are material inefficiencies, are these driven by any subset of non-scheduled controllable generators with nameplate ratings between 5MW and 30MW? For example, non-scheduled controllable generators with nameplate ratings between 20MW and 30MW, or non-scheduled controllable generators with nameplate ratings between 5MW and 30MW that are operated in tandem.	See above comments. The MEU points out that the impact of weather on micro generation (rooftop solar PV) has a greater impact on the market than generators <30MW>5MW
	3. To what extent do price responsive non-scheduled	See comments above and responses to Q1.1 and Q1.2

	generators below 5MW and price responsive non-scheduled customers cause inaccuracies in the dispatch demand forecast and to what extent do such inaccuracies result in inefficiencies in the dispatch process through: **(a) the spot price being set at a level which does not reflect the actual supply and demand conditions in the market?** **(b) the cost of scheduled generation meeting actual demand not being minimised?** **(a) (c) increases to the cost of supply through higher FCAS costs in the long run?**	above
2	**1. Are specific market participants or types of market participants more significantly impacted by any inefficiencies in the dispatch process caused by inaccuracies in the dispatch demand forecast related to controllable non-scheduled generators between 5MW and 30MW?**	The MEU cannot see why specific demand side users would be impacted. The assertion is that larger generators are impacted but this has to be tested by assessing the real variation impacts of the small generators and load variations that already occur
	2. Are the inefficiencies caused by inaccuracies in the dispatch demand forecast related to controllable non-scheduled generators between 5MW and 30MW more significant at specific times and/or under certain market conditions?	No. The MEU points out above that the majority of small generators are an adjunct to other operational processes (eg as cogenerators and the demand for steam) unrelated to the electricity market
	3. Are specific market participants or types of market participants more significantly impacted by any inefficiencies in the dispatch process caused by inaccuracies in the dispatch demand forecast related to controllable non-scheduled generators with nameplate ratings below 5W or non-scheduled loads that are price responsive?	See response to Q2.1

	4. Are the inefficiencies caused by inaccuracies in the dispatch demand forecast related to price responsive controllable non-scheduled generators below 5MW and non-scheduled loads more significant at specific times and/or under certain market conditions?	Micro generation (eg roof top solar PV has a significant impact on the demand profile which is greater than the impact of load shedding and/or small generators
3	**1. To what extent do controllable non-scheduled generators with nameplate ratings between 5MW and 30MW cause inaccuracies in the pre-dispatch demand forecast and to what extent do such inaccuracies result in inefficiencies in the price discovery process?**	Due to the operational requirements, the MEU considers that the bulk of small generators do not vary their outputs in response to the electricity market as this would cause significant problems for processes unrelated to the electricity market
	2. To what extent do price responsive controllable non-scheduled generators below 5MW and price responsive non-scheduled loads cause inaccuracies in the pre-dispatch demand forecast and to what extent do such inaccuracies result in inefficiencies in the price discovery process?	See response to Q3.1 As noted in comments in section 1, load varies just as much if not more than when price responsive load shedding occurs
	3. Are specific market participants or types of market participants more significantly impacted by inefficiencies caused by inaccuracies in the pre-dispatch demand forecast?	The MEU considers there is little impact as the small generators have little impact on the market and price responsive load shedding has less impact on the market than normal demand variation and generation from micro-generators
4	**1. Is there a case for reviewing the threshold for generators to be scheduled? If so:** **(a) Would a decrease in the threshold to be classified as a scheduled generator from 30MW to 5MW reduce inefficiencies in the dispatch and pre-dispatch/price discovery process? Is there a more preferable**	The MEU points out that the current thresholds have resulted in a workable market and to reduce the threshold will impose significant costs for little or no benefit

	nameplate rating threshold? **(b) Would a more flexible threshold for the requirement to be scheduled reduce inefficiencies in the dispatch and pre-dispatch/price discovery process? If so, what should be taken into account in a more flexible threshold?**	
5	**1. Should price-quantity response bands submitted by price responsive soft scheduled participants be able to set the dispatch price? If so, is this consistent with the requirement that soft scheduled generators' price-quantity bids are not subject to network constraints or follow dispatch instructions?**	The MEU does not consider the concept of "soft scheduled" generation or loads is workable or would deliver any benefit to the market
	2. If soft scheduled generators do not receive, and are not required to follow dispatch instructions, what (if any) enforcement mechanism should be in place to require them to provide accurate information regarding their generation intentions? To what degree will the benefits of extra information in the pre-dispatch schedule and dispatch process regarding these generators intentions be reduced if they are not issued with, and required to follow dispatch instructions?	See response to Q5.1
	3. Is there a risk that information submitted by price-responsive and non-price responsive soft scheduled generators may be used strategically to influence the bid stack (price-responsive) or the demand forecast (non-price responsive generators) and hence market outcomes?	The MEU considers that the Snowy and Engie proposals are all about using the information strategically to the detriment of consumers.
	4. If this solution is applied to price responsive loads over	The MEU has provided comment in its response to the

	30MW to what extent (if any) is it likely to reduce the benefits of the proposed rule in the Demand side obligations rule change request?	Snowy proposal and in section 1 above
6	**1. To what extent is this solution likely to increase efficiency in the dispatch process through including proxy bids to capture the price responsiveness of non-scheduled generators and non-scheduled loads?**	AEMO forecasts already incorporate its view on likely demand and the bids provided to it by the large generators. This process has served the market well for nearly two decades. The benefits of the rule change proposals are likely to be modest at best, if at all.
	2. Should proxy bids by AEMO be able to set the prices in a dispatch period? If so, is this option consistent with AEMO's role as an independent market operator?	The MEU is concerned that AEMO would be a surrogate bidder as well as being the independent operator. There is significant risk of a conflict of interest. Further, should AEMO make an error with its surrogate bidding process and caused a significant problem, AEMO could be liable for the costs to market participants and/or consumers. This is not acceptable.
	3. What safeguards would need to be in place to ensure that AEMO's role as an independent market operator is not compromised?	The option should not be implemented
	4. What would be the benefits of applying this solution more broadly than ENGIE has proposed? For example, could this solution be applied to the large price responsive loads proposed to be scheduled in the Demand side obligations rule change request?	The MEU considers that AEMO could not be expected to understand the various decisions that are made by individual end users when considering the option to load shed or not, or at which price points the load shedding might be undertaken. The MEU pointed out in its response to the Snowy proposal that other issues impact a decision to load shed than just the price of electricity (eg the commitment to a downstream buyer

		and the level of stock held). For this approach to be accurate, each end user deciding to load shed would have to provide AEMO with input data on their loading shedding protocols and this is unlikely to be provided to AEMO as the protocols can be over-ridden under certain circumstances.
	5. What are the data and technical requirements for implementation of this option?	These would be extensive and different for each party considering load shedding. Further, a reduction in demand by an end user is more often caused by other concerns than the price of electricity, so the actions by AEMO would perforce only address a very small number of the actual changes in demand.
7	**1. Could information provision and information aggregation be achieved through market-based incentives rather than regulatory measures? If so, in what form?**	The MEU cannot see what incentives could be provided when the costs of electricity for end users is not the only input cost faced and these other costs and operational requirements could be much more significant.
	2. Are there any examples in other markets (in Australia or overseas) where information provision and information aggregation solutions are utilised through non-regulatory means?	
8	**1. Are ENGIE's estimates of the costs of each proposed solution on AEMO and controllable non-scheduled generators accurate? If not, what are the likely costs of each solution?**	As noted above, the MEU considers that the costs are grossly underestimated when compared to the costs incurred in) establishing operating controls for those with

		exposure to the spot market and) the costs that are likely to be incurred on an ongoing basis.
	2. Are the costs likely to vary for some non-scheduled generators from others? For example, would the costs of becoming scheduled vary for: **(a) Existing non-scheduled generators required to become scheduled?** **(b) Non-scheduled generators whose primary focus is not generating electricity?** **(c) Types of generation?**	The MEU cannot see why the costs would vary. The MEU has provided an indication of the costs incurred for taking spot market exposure and in assessing how an end user would have to provide staff to implement ongoing data provision to AEMO
	3. Is a reduction in the threshold for controllable generators likely to affect the incentives for captured generators to enter or interact with the market? If so, what is the likely effect of such a change?	As noted in section 1, most small generators operate as part of other manufacturing processes (eg cogeneration and steam raising) and their operation is driven by needs other than the electricity market and other small generators are involved in the renewables market as well as the electricity market with the provision of RECs more important than the price of electricity. The MEU considers that these other markets are more likely to influence the operation of the generators than the electricity market.