26 May 2016

Ben Davis
Project Leader
Australian Energy Market Commission
Submitted via website
AEMC reference - ERC0203

Dear Ben,

Thank you for the opportunity to provide comment on the Australian Energy Market Commission's (AEMC's) consultation paper on Non-scheduled generation and load in central dispatch (consultation paper). We note the consultation paper has been prepared in response to rule change requests from ENGIE and Snowy Hydro relating to improving the market price signal and enhancing the technology neutrality of information provision and compliance arrangements in the NEM.

Stanwell is a registered generator, market customer, intermediary and small generator aggregator in the NEM, operating both scheduled and non-scheduled generation sites.

Stanwell supports the AEMC combining the rule change proposals, however we note that the consultation paper primarily addresses the ENGIE rule change proposal, rather than a consolidated more preferential rule change proposal. Stanwell supports the intent of the rule change request(s) and considers that supplementing the ENGIE proposal to include non-scheduled load is likely to be a more preferable outcome than the mechanism proposed in the Snowy rule change proposal.

Overall, Stanwell considers that the qualitative benefits of the proposed rule change are far in excess of the potential costs. The proposed "mechanism 1" is likely to provide the most significant improvement in market transparency and efficiency, with mechanisms 2 and 3 providing pragmatic compromises in challenging policy areas. Mechanisms 1 and 2 are consistent with the AEMC's recent Final Determination on *Registration of proponents of new types of generation* which states "*An increase in sources of Generator bids may also result in more efficient dispatch solutions.*"[1]

Given the complexity of the rule change proposal, Stanwell suggests the AEMC issue an options paper prior to making a draft determination.

The attached submission contains both answers to the specific questions in the consultation paper and a number of related issues. If you would like to discuss any aspect of this submission, please contact me on 07 3228 4529.

Regards

Luke Van Boeckel
Manager Regulatory Strategy
Energy Trading and Commercial Strategy

[1] AEMC 2016, *Registration of proponents of new types of generation, Rule Determination*, 26 May 2016, Sydney, page 6

Related rule changes and rule change requests
While the consultation paper identifies links to the

- *Bidding in Good Faith*,
- *Compliance with Dispatch Instructions* and
- *Five Minute Settlement*

rule change processes, Stanwell also considers that the rule change proposal has linkages to the

- *Improving demand side participation information provided to AEMO by registered participants* and
- *Demand Response Mechanism and Ancillary Services Unbundling* processes.

The recently completed *Bidding in Good Faith* and *Compliance with Dispatch Instructions* rule change processes are particularly relevant as they reinforce the importance of accurate, transparent information being provided to AEMO and then on to market participants. In both cases, the AEMC determinations also provide clarity that the impost associated with these measures is considered efficient. Stanwell considers that such rationale easily extends to the (potential) participant types covered by this rule change proposal.

The recently initiated *Five minute settlement* rule change could potentially alter outcomes for all covered participants, however at this stage it is unclear whether and to what extent this proposal will progress.

The *Improving demand side participation information provided to AEMO by registered participants* and *Demand Response Mechanism and Ancillary Services Unbundling* are relevant to the question of the required level of notification to AEMO by non-scheduled load and unscheduled generation[2].

In accordance with the final determination and final rule on *Improving demand side participation information provided to AEMO by registered participants*:

1. *Registered Participants* must provide demand side participation information to *AEMO* in accordance with the (yet to be published) demand side participation information guidelines,
2. *AEMO* must take into account the demand side participation information it receives when developing or using *load* forecasts, and
3. *AEMO* must publish details, no less than annually, on the extent to which, in general terms, demand side participation information has informed *AEMO's* development or use of *load* forecasts.

Stanwell considers that this information is likely to be fundamentally similar to that supplied by the proposed soft-scheduled participant class (assuming a technology-neutral approach where both generation and load are able to be classified as soft-scheduled). The AEMC has previously noted that "*This rule change may impact on the quality of AEMO's load forecasts, from short term forecasts such as 5 minute pre-dispatch, to long term forecasts such as the ten year forecasts in the National Electricity Forecasting Report*."[3]

[2] Terminology adopted from *Improving demand side participation information provided to AEMO by registered participants* rule change final determination. Unscheduled includes non-scheduled and registration exempt generators.

[3] AEMC 2016, *Demand Response Mechanism and Ancillary Services Unbundling*, Consultation Paper, 5 November 2015, Sydney, page 8

Under the proposed *Demand Response Mechanism* "*A new class of market participants, demand response aggregators (DRAs), would self-schedule customer's demand response in the wholesale spot market.*"[4] This would be achieved via notifications to AEMO. The consultation paper's proposed soft scheduling requirements appear superior to the proposed DRM arrangements in that they provide AEMO with notice of the intent and extent of the proposed demand response, rather than simply its timing.

Retrospectivity, grandfathering and transition issues

Stanwell welcomes the explicit recognition that *"The Commission is cognisant of effects of making changes to the Rules that apply retrospectively, for example ENGIE's proposal to require existing registered non-scheduled generators to become scheduled"*[5]*.* Stanwell considers that this statement may benefit from clarification – the nature of the AEMC's role is that it regularly applies new obligations and/or new interpretations on existing participants. Accordingly this response assumes the concept of retrospectivity applies in this instance to whether new obligations or conditions of registration apply from a date in the future or a date in the past[6].

We note that "mechanism 1" of the ENGIE proposal is to apply this change only to existing generation *which have an existing capability to be scheduled*. Conversely, non-scheduled wind generators are not proposed to become semi-scheduled regardless of capability. Stanwell does not support this inconsistency. We also consider that the threshold to gain "grandfathering" of the exemption from becoming scheduled should be set high in order to minimise distortions such as those associated with "mechanism 2", discussed later in this response. Stanwell supports the threshold change for new generators and loads being applied close to the time of determination, with a longer implementation time for imminent and existing participants. Consistent with our submission during the *Bidding in Good Faith* rule change process, we consider that existing participants are likely to require at least 12 months between the determination and scheduled start date.

"Mechanism 2" - the proposed new "soft scheduled" category - would provide significantly greater information and transparency than currently exists, at significantly less cost and complexity[7] to the participant than becoming scheduled. Mechanism 2 is also more akin to the AEMC's "normal" rule change process – applying new obligations from a future date on existing participants. Stanwell supports these arrangements being applied to existing generation and load with appropriate lead times. Consistent with our submission during the *Bidding in Good Faith* rule change process, we consider that participants are likely to require at least 12 months between the determination and scheduled start date. Whether mechanism 2 is formally adopted, or forms part of AEMO's existing discretion should be examined during this consultation.

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[4] Ibid, page 1

[5] Consultation paper, p19

[6] Notably the rule change request includes a reference to 1 January 2016 which was *prospective* at lodgement but would be *retrospective* by the time a rule was made.

[7] Depending on specific implementation.

"Mechanism 3" appears primarily dependent on AEMO's implementation of systems and therefore is unlikely to be affected by concerns around retrospectivity.

Consistency of offer deadlines and classification thresholds
The rule change proposal is silent with regards to the threshold for registration as a semi-scheduled generator, while the consultation paper indicates that no change to this threshold is being considered. Stanwell considers that the threshold for semi-scheduled registration should be reviewed in conjunction with that for scheduled registration, particularly in light of the forecast increase in intermittent generation. Semi-scheduled registration is also currently subject to a 6MW threshold[8] in relation to the aggregation of individual machines. This may require revision in conjunction with any lowering of the semi-scheduled registration threshold.

The consultation paper also states *"while scheduled generators are required to submit their bids in advance for the upcoming trading day, no such requirement is proposed by ENGIE for soft-scheduled generations. However, in practice, it may be practical for soft-scheduled generators to define their price and/or quantity for several trading intervals or even days in advance"*

Stanwell supports soft-scheduled generators operating to the same AEMO timetable as scheduled and semi-scheduled generators. This includes both the requirement to provide day-ahead offers prior to 12:30pm, and the ability to update offers until immediately prior to dispatch. The current rules also allow generators to submit bids "days in advance".

Compliance reporting
Stanwell does not support the proposed compliance reporting from soft-scheduled participants to the AER on a monthly basis, so long as soft scheduled participant bids and generation (or consumption) are available to the market in an equivalent manner to those of scheduled and semi-scheduled participants. Such information provision would allow regulators and market participants to consider the published intent of soft-scheduled participants in a manner consistent with their current analysis of scheduled and semi-scheduled generators. This analysis includes the effect and timing of rebids close to dispatch and the consistency of a participant's behaviour.

[8] NER Clause 2.2.7(i)(2)

Question 1 Potential inefficiencies in the dispatch process

Q1.1 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?**

A. Stanwell considers that this question is artificially narrow, reflecting focus only upon the ENGIE rule change proposal. In general terms[9] there is no way for observers to distinguish between non-scheduled load and unscheduled generation, and no way to distinguish between sub-types of unscheduled generation.

In qualitative terms these questions appear consistent with the analysis presented in the AEMC's final determination[10] not to make a rule in response to the *Compliance with Dispatch instructions* rule change request. That determination makes no reference to specific capacity levels at which a market participant's non-adherence to AEMO's expectation is considered material, however recent action by the Australian Energy Regulator has indicated that this level may be below 30MW[11].

The consultation paper notes that uncertainties are inherent in all forecasts[12]. Stanwell agree that forecasts will never be perfect, but consider that efficiently reducing the number of sources of uncertainty will provide significantly greater ability to address the residual. As addressed later in this response, we consider that the qualitative benefits of the proposed rule change are far in excess of the potential costs.

All non-transparent participation results in inefficiencies and reduced confidence in the market process. Within a dispatch interval or trading interval, non-transparent actions cause unnecessary costs to be incurred by responsive generators, as will be elaborated on in response to Q2.1. The presence of significant volumes of such activity also erodes the value of pre-dispatch both directly and indirectly.

Scheduled and semi-scheduled participants must account for much greater degrees of uncertainty when formulating offers, decreasing the likelihood that an offer will ultimately reflect the participant's intended outcome under the conditions observable close to dispatch.

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[9] We acknowledge that for some specific sources this information is able to be determined – for example some non-scheduled generation publish output values.

[10] http://www.aemc.gov.au/Rule-Changes/Compliance-with-dispatch-instructions

[11] http://www.aer.gov.au/wholesale-markets/enforcement-matters/infringement-notices-issued-to-erm-power-for-failure-to-follow-dispatch-instructions

[12] *"The Commission is therefore conscious that where the problem identified relates to inaccuracies in the dispatch and pre-dispatch demand forecasts, the benefits of such reductions will need to be considered in the context of the uncertainty that is inherent in forecasting electricity demand."* Consultation paper p18

Such divergence gives rise to increased rebidding, and particularly “late”[13] rebidding as inputs become relatively less variable. This further erodes participants’ confidence in the reliability of pre-dispatch signals.

Market operators and regulators must consider how to account for un-notified activity when managing and reviewing the operation of the market. For example recent reporting by the AER indicates that prices are diverging from predispatch more frequently than has been observed in previous years with a significant portion attributed partially or primarily to load variations. The weekly report for 1-7 May 2016[14] states:

> *There were 331 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2015 of 133 counts and the average in 2014 of 71.*

Table 2: Reasons for variations between forecast and actual prices

	Availability	Demand	Network	Combination
% of total above forecast	7	17	0	6
% of total below forecast	39	21	0	11

Note: Due to rounding, the total may not be 100 per cent.

While the specific number of intervals and percentage split of reasons varies from week to week, the reports for preceding weeks are consistent with this analysis.

Q1.2 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.

A. Addressed in response to Q1.3 below.

Q1.3 To what extent do price responsive non-scheduled 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?**
>
> **(c) increases to the cost of supply through higher FCAS costs in the long run?**

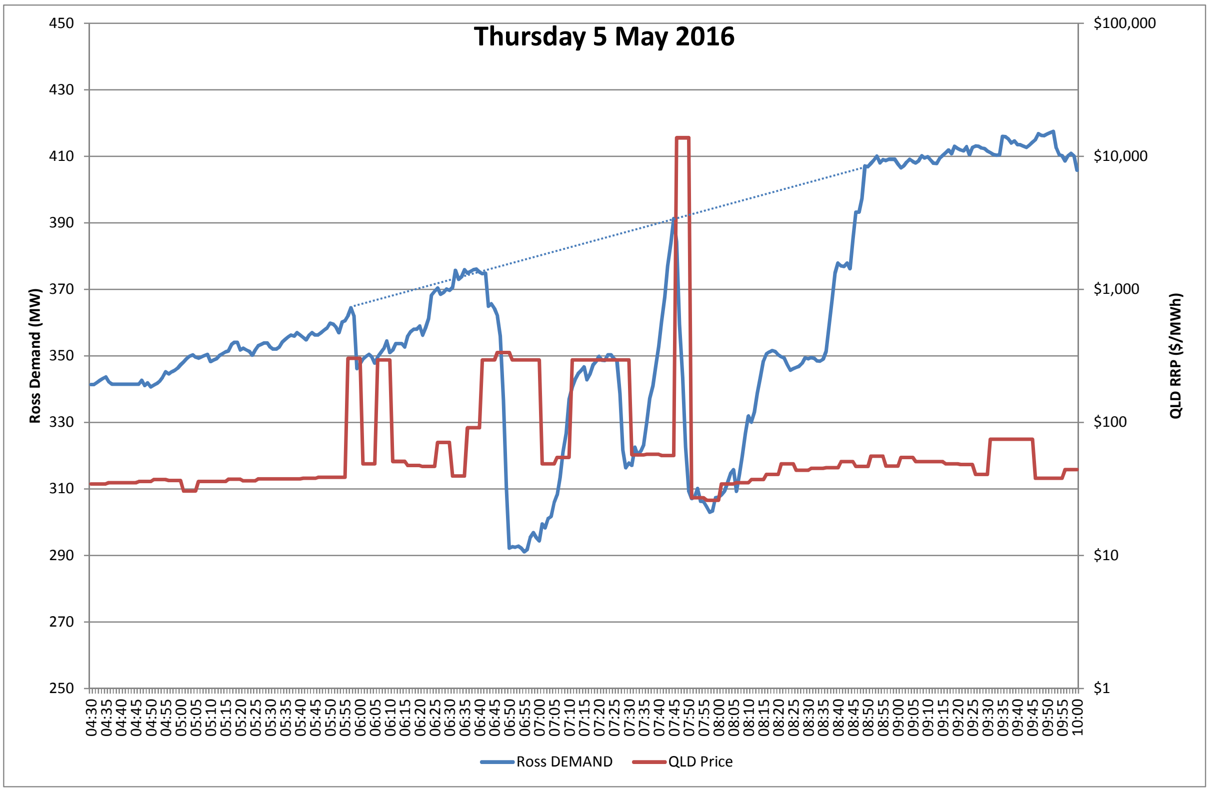
A. In general terms there is no way for observers to distinguish between non-scheduled load and unscheduled generation, and no way to distinguish between sub-types of unscheduled generation. Logically larger variations will have greater impact. Actions of small generators or loads which are aggregated are likely to be indistinguishable from actions of a single site, other than in relation to network constraints.

[13] The use of the term late in this context refers to activity close to the end of the auction. Despite the terminology this is distinct from the issue which was the focus of the AEMC’s draft and final determinations in relation to the 2015 *Bidding in Good Faith* rule change – more accurately described as delayed rebidding.

[14] Latest available at time of writing

Stanwell and other participants have previously provided[15] examples of dispatch variances well in excess of 30MW which would logically be the result of non-scheduled customers unilaterally varying their consumption. The recent example included below shows that within a single sub-region of Queensland demand can change in the order of 80MW in as little as one minute, logically giving rise to significant "regulating lower" Frequency Control Ancillary Services (FCAS) provision (not shown). This example also indicates that this non-transparent load variation significantly impacted the spot price. The $13,795/MWh dispatch interval apparently incorporated the restored load at 391MW – load which was then rapidly removed from the system in apparent response to the high spot price. The AER weekly report describes this event as

> *With a 108 MW increase in demand and lower priced capacity either ramp rate limited or fully dispatched, the price increased from $46/MWh at 7.45 am to $13 795/MWh at 7.50 am.*



Question 2 Impacts on market participants from inefficiencies in the dispatch process

Q2.1 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?

A. Stanwell considers that there are three types of market participants who may be significantly impacted by inaccuracies in dispatch demand forecasts.

1. Providers of ancillary services, particularly regulating raise and lower, are likely to incur unanticipated additional wear and tear as well as unforecast variations in energy revenue through the increased activation of their services.

[15] For example Stanwell, ERM responses to *Demand Response Mechanism and Ancillary Services Unbundling* Consultation Paper, available from http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism

2. Participants whose control systems automatically respond to frequency will be similarly affected by wear and tear, but do not receive even the meagre compensation afforded to FCAS providers.
3. Participants who incur significant costs in response to an activation signal (e.g. gas turbine start up or industrial process shut down) but are then unable to recover sufficient benefit due to un-forecast changes in spot price outcomes will also be negatively affected.

Q2.2 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?
A. Stanwell considers that there is unlikely to be a "one size fits all" answer to this question. Controllable generation (or load) may respond to wholesale price or be primarily driven by related industrial processes.

The impact of either type is more likely to be material in relation to condition (a)[16] at times when the supply curve is steep but largely immaterial when the supply curve is flat. Price sensitive generation and load are likely to be particularly active around such sensitivity points whereas non-price responsive generation and load changes are more likely to impact the market under a wider range of conditions.

Similarly, the impact of either type of response could have the same impact on condition (b), however price responsive generation (or load) is notionally more likely to be active during market conditions where there are step changes in the supply cost. This may occur due to the cost involved in starting peaking plant or changes between the short run costs of different generating technologies.

In relation to condition (c) Stanwell has not examined the impact in detail but considers that most of the time the impact on FCAS prices would be minimal. We consider that AEMO's procurement strategy is likely to be the most significant driver of FCAS costs. If AEMO consider that additional FCAS resources are required the cost to the market will increase. Otherwise FCAS costs are likely to remain extremely marginal compared to other components of wholesale and retail energy prices.

Q2.3 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?
A. Addressed in response to Q2.1 above.

Q2.4 Are the inefficiencies caused by inaccuracies in the dispatch demand forecast related to price responsive controllable non-scheduled generators below 5MW and

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[16] (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

non-scheduled loads more significant at specific times and/or under certain market conditions?
A. Addressed in response to Q2.3 above.

Question 3 Potential inefficiencies in pre-dispatch
Q3.1 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?
A. Addressed in response to Q1.1 above.

Q3.2 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?
A. Addressed in response to Q1.3 above.

Q3.3 Are specific market participants or types of market participants more significantly impacted by inefficiencies caused by inaccuracies in the pre-dispatch demand forecast?
A. Stanwell considers that all market participants are adversely impacted by the uncertainty and inaccuracies in pre-dispatch. Scheduled and semi-scheduled participants are typically at a greater disadvantage due to the requirement to formulate and publish an offer and then wait for a dispatch instruction in response to changed market conditions. Non-scheduled and unscheduled participants do not experience such a delay, they can alter their participation at any time based on any of their own criteria. As discussed under question 1.1, the impacts of pre-dispatch errors are both direct and indirect. One indirect impact of pre-dispatch inaccuracies is increased "late" rebidding by scheduled generators.

Question 4 Option one
As noted in Section 4.2, the Commission considers the appropriate solution will depend on the materiality and sources of the issues analysed in Section 5.1. The questions below seek stakeholders' views in the context of addressing both the materiality and source of the inefficiencies.
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 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?

A. As indicated in the rule change request, there is in the order of 1000MW of market non-scheduled wind generation in the NEM, being those sites which existed prior to the creation of the semi-scheduled participant class. The semi-scheduled category was added in part to reflect the growing impact on market efficiency being caused by an increasing number of non-scheduled wind generation sites. The same analysis shows in excess of 1100MW of market non-scheduled (non-wind) generation in the NEM, indicating that the issue is of similar magnitude and a review of the threshold is warranted.

As indicated in response to the preceding questions, Stanwell considers that decreasing the threshold is likely to significantly increase market transparency at a relatively low cost compared to the benefit derived. We have also noted that the impact of non-scheduled load and unscheduled generation is likely to be broadly proportional to the size of the systems (including aggregated systems).

While the proposed reduction from 30MW to 5MW aligns with the current AEMO determined exemption level there appears to be no other specific rationale. Stanwell considers that there may be merit in setting the threshold as low as 1MW. This is the granularity at which bidding can currently occur and also the level at which unilateral action may result in a change to the spot price. It is also notable that the capability of information technology systems has improved markedly since the 30MW and 5MW thresholds were adopted further strengthening the argument for reviewing the threshold.

Stanwell considers that AEMO holds a significant amount of discretion under the current rules in relation to registrations, and this is likely to be beneficial to retain going forward. This negates the need for a "flexible" threshold.

Question 5 Option two

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?

A. Stanwell considers that it would be inconsistent and inefficient if the dispatch price were able to be set by market participants who do not receive dispatch instructions. There are a number of references in the rules to the principle that *central dispatch* is to be the tool used to provide consistent *dispatch prices* and *dispatch instructions*[17].

AEMO issues dispatch instructions in order to fulfil its obligation to maintain the NEM in a secure state at the lowest cost. The strong obligations that are placed on the recipients of these instructions provide AEMO with confidence that the system will be maintained in an appropriate state and that dispatch prices reflect supply and demand conditions.

If the rule change is broadly consistent with the proposals, soft scheduled participants would be limited to legacy generators who do not have the capability to be scheduled and loads who do not have the desire. Neither group would be expected to consistently respond to AEMO instructions to alter their output or consumption to specific levels in response to network constraints. Indeed, participants who are capable and willing to respond already have the option to become scheduled or semi scheduled.

Further, under current market design, spot prices are regularly affected by constraints which vary the participation level and therefore dispatch targets of generators, loads and interconnectors. It is unclear how soft scheduled participants could participate in one element of this relationship without participating in the other.

For example, were a soft scheduled unit to be used to set price, the constraint formula would have to be adjusted to account for the "implied" dispatch target being given to the soft-scheduled participant. The implied dispatch target could not be co-optimised by AEMO in the constraint equation with actual dispatch targets, however the energy delivered by the soft scheduled participant would need to be accounted for.

[17] For example Market Design Principle 4, NER clause 3.1.4(a)

In a constraint condition (often associated with high prices), a soft scheduled generator or load may unilaterally increase generation or reduce load. Doing so may worsen a binding constraint in an equivalent manner to increasing generation from a scheduled generator[18]. The offer from the scheduled generator would be incorporated into the AEMO dispatch process[19] and would receive a dispatch target. The scheduled generator would be capable of setting price (likely in conjunction with other constrained units). Often the spot price under such conditions is the result of a complex interaction of multiple bids and the impact of the constraint on multiple participants.

Critically, AEMO's dispatch engine formulates price on the basis of the scheduled delivery of energy, something which may not be reliably supplied by a soft scheduled participant.

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?

A. Stanwell would expect that soft scheduled participants be subject to a behavioural statement of conduct similar to that which applies to scheduled and semi-scheduled participants. That is, that bids must be provided *in good faith* or *must not be false, misleading or likely to mislead*[20]. Similarly, soft scheduled rebids would be allowed where *the Generator or Market Participant becomes aware of a change in the material conditions and circumstances upon which the offer, bid or rebid are based*[21]. Stanwell would expect that such an obligation would be a civil penalty provision[22]. Where limited (or no) compliance obligation exist, patterns of behaviour could be one avenue used to infer whether a soft scheduled participant's offers are reflective of their intent in the same manner as for scheduled generators under existing rules.

The value of information in the pre-dispatch schedule will depend heavily on AEMO's approach to the incorporation of the information. Stanwell considers that soft scheduled generation information should be excluded from pre-dispatch but published (in aggregate) by AEMO as a sensitivity run – potentially based on the spot prices in pre-dispatch. This is consistent with soft scheduled participants being unaffected by network constraints and unable to set dispatch price.

This approach would reflect the difference between participant classes and would provide a quantitative evaluation of the impact of soft-scheduled participants on market outcomes. It

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[18] As indicated in the consultation paper, load registering to be scheduled is extremely rare and is therefore excluded from this example.

[19] AEMO's dispatch engine ensures the various increases and decreases to targets provide a net delivery of one additional MW.

[20] Wording consistent with NER clause 3.8.22A(a) before and after 1 July 2016 respectively.

[21] Wording consistent with NER clause 3.8.22A(a1) after 1 July 2016

[22] Whether the obligation is a *civil penalty provision*, *rebidding civil penalty provision* or new type of civil penalty provision is immaterial to the consideration at this stage.

would also provide context for post event analysis by entities such as AEMO and the AER. In addition, this approach would not change AEMO's dispatch algorithm or the affect of soft scheduled generators on AEMO's management of system security.

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?
A. This issue will depend on the compliance obligation, enforcement mechanism and enforcement approach developed in relation to the new participant class and the approach taken as to whether such participants can set the price.

If soft-scheduled generators and loads are allowed to submit information which is deliberately misleading there would be significant scope to undermine market efficiency, particularly in relation to pre-dispatch outcomes. For this reason appropriate compliance obligations should be developed. However, it is unclear whether the impact on dispatch outcomes of this behaviour would be materially different to the current arrangements where no information is provided and no obligations exist.

4. If this solution is applied to price responsive loads over 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?
A. Stanwell considers that the non-scheduled generation rule change request would provide a more preferable solution relating to large or price sensitive loads than the *demand side obligation* rule change request. While it would be ideal from a "technology neutral" viewpoint[23] to have the same requirements apply to demand response and generation, Stanwell considers that this is unlikely to gain broad acceptance at this time. Applying the "soft scheduled" obligations on all load above 5MW (or other threshold determined during this process), while retaining the ability for loads to become scheduled appears to be a pragmatic compromise.

Question 6 Option three
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?
A. Stanwell considers that an arrangement similar to that proposed for soft scheduled participants would improve market transparency and allow the impact on dispatch efficiency to be assessed. That is, proxy bids should not be included in pre-dispatch or dispatch solutions but provided in aggregate as a sensitivity to pre-dispatch forecasts.

Mechanism 3 appears to be especially appropriate given the forecast increase in controllable and potentially aggregated storage devices. Developing targeted information regarding the behaviour and impact of such emerging technology is likely to be critical in determining

[23] The "technology neutral" approach is preferred in the Rules and is reflected in the AEMC's Integration of Battery Storage paper "*An underlying principle of energy market regulation in Australia has been technology neutrality. That is, the rules are not designed to bias the deployment of storage or any other technology.*" AEMO's rule change request (ERC0204) to change the definition of "generator" also aligns with the "technology neutral" goal.

whether market and regulatory settings remain fit for purpose in a changing technology landscape.

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?
A. Stanwell does not support proxy bids being used to set price, under the same rationale as provided for soft scheduled participants in Q5.1

3. What safeguards would need to be in place to ensure that AEMO's role as an independent market operator is not compromised?
A. Stanwell considers that an arrangement similar to that proposed for soft scheduled participants would minimise the chance of AEMO's independence being compromised. That is, proxy bids should not be included in pre-dispatch or dispatch solutions but provided in aggregate as an additional pre-dispatch sensitivity forecast.

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?
A. Stanwell considers that proxy bids should only be used for large loads where those loads cannot be included in mechanism 1 or mechanism 2. Stanwell's response to Q1.3 provides an example of a large load which appears price responsive and controllable, and should be at least soft scheduled.

5. What are the data and technical requirements for implementation of this option?
A. Stanwell has no specific information in relation to this issue.

Question 7 Alternative solutions
1. Could information provision and information aggregation be achieved through market-based incentives rather than regulatory measures? If so, in what form?
A. Stanwell considers that market-based incentives are generally superior to regulatory measures, however we do not support an environment of incentives for some and burdensome regulation for others.

If a valid market-based incentive approach is identified in relation to non-scheduled load and unscheduled generators, then it is appropriate to seek to apply it to all participants on a technology- and participant size- neutral basis.

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?
A. Stanwell has no specific information in relation to this issue.

Question 8 Costs
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?
A. Stanwell considers that the cost estimates provided in the rule change request are likely to be conservatively low, but broadly reasonable. Even if the costs were higher, the likely benefits of the proposed rule change far exceed the costs.

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?

A. ENGIE appears to have appropriately distinguished the cost estimates for participants based on which “mechanism” they are affected by. Costs for participants adding existing non-scheduled generation and demand response to existing systems are likely to be lower than for participants developing systems from scratch.

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?

A. Stanwell does not consider that a reduction in the threshold will have material impact on the incentives to enter the market. This is especially the case as *Intermediaries* and, if approved, *Demand Response Aggregators* are likely to be able to offer market interaction services at a lower cost than independent setup by the individual loads or generators. In such circumstances it may be beneficial to review whether *Small Generator Aggregators* should also be able or required to bid into central dispatch[24].

In any event, the “captured generators” would also benefit from the increased transparency, market efficiency and technology neutrality arising from the proposed rule change. While a non scheduled generator’s obligation to provide information on their intentions may increase, so would those of their competitors on both the generation and demand side.

[24] Stanwell notes that the AEMC have previously recommended “AEMO conduct an assessment of the existing registration category of small generation aggregator”, however it is not clear whether this assessment is limited to aggregation of extends to broader market participation.