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# Dispatch and Pricing Procedure
# Consultation Submission

Eni Australia Limited (EAL) makes this submission to Power and Water Corporation (PWC) for the draft "System Control I-NTEM Dispatch & Pricing Procedure".

**Background**

The Eni group has been present in Australia through its subsidiaries since year 2000. Eni Australia BV is the operator and 100% owner of the Blacktip Gas Project which has supplied domestic gas to the NT since 2009. In January 2019, Eni Australia Limited (EAL) completed the acquisition of a construction-ready solar photovoltaic (PV) project near Katherine, from Katherine Solar Pty Ltd, a joint venture between Australia's Epuron and the UK-based Island Green Power. In October 2019, EAL completed the acquisition of two further construction-ready solar photovoltaic (PV) projects at Batchelor and Manton Dam, from NT Solar Investments Pty Ltd, a wholly owned subsidiary of Australia's Tetris Energy.

**Consultation Questions**

*Does the procedure provide sufficient detail to inform Generator Participants of how information they submit under other procedures is used in the pre-dispatch, dispatch and pricing processes?*

There is no information in this document regarding the impact of forecasts made under Clause 3.3.5.17 of the Network Technical Code and the Generator Forecasting Compliance Procedure (GFCP), other than the impact of any non-compliance with the latter document being included in the definition of real time unit availability. However, the implications of the forecasts themselves on dispatch are not specified. Presumably, if no non-compliances with the GFCP have occurred, then real time unit availability will not be impacted.

For reasons we have elaborated on elsewhere, reliably forecasting a capacity above 0 MW for our solar farms is not possible, for reasons beyond our control. Therefore, in order to be compliant with 3.3.5.17, we must always forecast a capacity of 0 MW, as that is the only level of capacity that we can guarantee from our facilities.

Due to the document's silence on these issues, we have therefore assumed that such forecasts do not directly impact on commitment or dispatch from our facilities. It would be helpful if this could be explicitly confirmed.

*Is the procedure a useful aid for prospective Generator Participants and to help staff of existing Generator Participants to understand the broad operation of the market and dispatch arrangements?*

The document seems to have been designed around conventional, synchronous generation. It is quite difficult to confirm the implications for solar generators. However, we have assumed that:

- Our minimum stable load will be 0 MW and our band 1 quantity will be 0 MW;
- We have no excess or "sprint" quantity to offer;
- Therefore, all our prices and quantities will be in band 2;

There is also no definition of a "fast start generating unit" within the document. It appears that conventional generators on the DKIS can take up to 30 minutes to start, which is well in excess of industry standards. It may be prudent to use a different term or specify that only generators that can start within a more reasonable time (e.g. 10 minutes) can qualify for this treatment.

*Are there any specific areas of the draft procedure that are difficult to understand or could be improved?*

The term "dispatch" is used in this document to describe starting, stopping and increasing or decreasing the loading of a generating unit. This is often confusing to read as the intended meaning can change even within a sentence. We suggest distinguishing properly within the document between unit commitment / de-commitment and increasing or decreasing the dispatch from a committed unit.

For conventional generators who must comply with the Generator Forecasting Compliance Procedure, it is clearly impossible to forecast any capacity above 0 MW for any specific interval when they may be de-committed by System Control at any moment. This would prevent them from providing any capacity for subsequent intervals, according to the definition of capacity in Clause 3.3.5.17 of the Network Technical Code. This would occur while the subsequent forecasts for the intervals immediately after being de-committed are not permitted to be lower than their previous forecasts for those same intervals.

It is therefore clear that a generator with a ten-minute start time cannot forecast any capacity above 0 MW for the intervals that are ten minutes following their de-commitment, to use just one example. That de-commitment could happen at any time and the only way to prevent their previous capacity forecasts for that interval exceeding their subsequent forecasts is to forecast a capacity of 0 MW for every interval. The same problem applies for forecasting any capacity for any future interval when a generator is currently stopped, due to the start time and a generator's lack of knowledge about when a unit will be committed. It would be useful for this fact to be made explicit and be referenced in this document, so as to remove potential confusion, particularly as it also relates to dispatch decisions.

*Are there any specific areas of the draft procedure that are in conflict with other documents?*

There appears to be some conflict between the 5 MW tie break treatment specified in this document and the "random number" tie break treatment specified in the Generating Unit Tie

Break Procedure. This document would benefit from more specific references to similar topics in other documents.

It would also be helpful to have some explanation of typical tie break arrangements for units that have no marginal cost (e.g. solar farms), when they both make zero offers. How the proposed 5 MW increments might be shared among different solar farms would also be useful, including how one solar farm might ramp up while the other ramps down.

Overall, it would appear to make the power system more resilient to unexpected cloud events if any constraints on solar generators on the DKIS (presumably the cheapest to dispatch of the Band 2 generators) were equally shared among them in real time, rather than cycled between them. Otherwise, cloud events at the solar farm that is currently being preferentially dispatched will have a disproportionate impact on the power system.

**Other issues:**
EAL offers the following further comments on this consultation:

*Inertia and Rate of Change of Frequency (ROCOF)*
The proposed procedure puts significant market outcomes at the mercy of what can be perceived as somewhat arbitrary "system security" decisions by the System Controller. These decisions should be made in a more open and transparent manner, with technical studies being published for industry consultation and regulatory review to justify them.

For example, it is noted that extremely high levels of inertia are mandated for this power system, much higher than for other power systems of similar size and structure in other jurisdictions, which are able to operate, for example, using 100% aero-derivative gas turbines. This appears to be a result of:

- PWC using Automated Generation Control (AGC) at Hudson Creek to control power system frequency centrally, rather than allowing individual generators to control frequency as measured on their own terminals (termed isochronous control).
- The time delays involved in sending signals to generators from a central location result in a much higher level of inertia than necessary being required compared to localised control but the choice to switch to isochronous control from individual generators appears both simple and easy.
- While large jurisdictions such as the NEM and the WEM use AGC, where it is likely to be appropriate, smaller jurisdictions such as the NWIS do not, for some of the reasons mentioned here. Generally speaking, in locations such as the NWIS, the use of isochronous frequency control by aero-derivative gas turbines results in a far more stable frequency (due to their faster speed of control) than frame type gas turbines.

Please note, it is impossible for EAL to discuss the detail of this issue any further as PWC will not discuss any of the associated technical detail with us. PWC should be open and transparent about the technical means used to operate the power system to all participants, otherwise all consultations such as this one are compromised by the lack of information provided. At the very least, potential means by which the power system may be optimised for the benefit of all participants, at lower cost to consumers, risk being overlooked. For example, this high level of inertia results in out-of-merit generators being committed for security reasons more than necessary, all of the time. This results in excessive costs and no real security benefit.

In terms of ROCOF, a ROCOF of 4 Hz/sec is often specified as being required to ensure stable control of the power system. This is not a proper treatment, for the following reasons:

- ROCOF limitations are typically set by the ability of connected generators to sustain that ROCOF. For example, gas turbines exposed to a high ROCOF run the risk of losing their blades due to the fast change in speed.
- Power systems (for example inverter based power systems) are able to operate stably with much higher ROCOF, provided the means of controlling those power systems is likewise just as fast, or faster. A faster ROCOF can result in a more stable power system if the speed of response from its control systems is commensurately faster.
- Therefore, it would be useful to note that incumbent generators are the real source of the requirement for a slow ROCOF. Then a genuine conversation can start about:
    - What level is really required;
    - Who should pay for measures designed to reduce ROCOF, such as increasing rotating or synthetic inertia. If incumbent generators benefit, then perhaps they should likewise pay for systems designed to reduce ROCOF.
    - Whether incumbent generators and control systems that are not fast enough to stabilise a faster ROCOF should be replaced by technologies that can.

In any case, PWC should publish the technical studies (and models) used to justify all system security policy decisions in committing band 1 generators, for industry comment and independent regulatory review (using different consultants than who prepared them in the first place). Otherwise, an approach may be taken that is as conservative as possible, with excessive costs being imposed on consumers through the obvious restrictions imposed on competition that flow from these decisions.

*Minimum Stable Loads*

When the above inertia and ROCOF requirements result in “must run” plant being (potentially unnecessarily) scheduled on, then they are run up to their “Minimum Stable Load” (MSL). It appears that there is little to no incentive for generators to nominate a low MSL and they have wide discretion and incentive to use a number of arbitrary technical criteria to nominate a relatively high MSL. In EAL’s view, this choice should be, at minimum, compared to the MSL able to be achieved for the same types of generators in other jurisdictions, particular those (such as the NEM), which operate a properly functioning “energy only” market.

Stability also needs to be defined by a certain time base such as stability for one minute, five minutes, one hour or 24 hours. If technical or environmental restrictions (e.g. NOx or SOx emissions) result in a certain MSL for a particular generator, then these should be published for independent review by the regulator following consultation with industry.

It is widely known that synchronous generators are able to significantly reduce previously assumed MSLs when given a financial reason to do so. This can be a result of a number of factors including control system changes and inexpensive retrofitting of new features designed to reduce MSL. It therefore appears likely that the lack of such a financial incentive in the DKIS will result in unnecessarily high MSLs in the DKIS for synchronous generators. That is unless a mechanism that is independent of government is put in place to prevent such a potential misuse of market power through this avenue, as has occurred in other jurisdictions. A number of mechanisms are possible for this and EAL would welcome consultation on the best approach which should be used in this instance.

MSLs should not be considered a purely technical feature as they are typically able to be reduced through a number of avenues and all efforts should be made to giving incumbent generators a financial incentive to do this, in order to let the market operate to the maximum extent possible.

*Network Constraints and Line Contingency*
Following on from this, the treatment of network constraints, such as the Channel Island to Katherine line contingency, from Section 5.5 may require review. The combination of the above inertia / ROCOF requirements being too onerous and MSLs that are too high will likely often result in inadequate FCAS levels being available north of Channel Island to deal with this contingency without curtailing solar farms. Using properly constructed requirements for these factors appears likely to prevent significant curtailment of solar farms on the Katherine line.

Likewise, the whole line appears to be treated as a single contingency, with no assessment of the likelihood of trips on the separate portions of this line. EAL notes that there are a number of other single contingency events that the DKIS is unlikely to be able to survive (e.g. busbar fault at Channel Island) and a probabilistic approach, as similarly used in other jurisdictions, is often used to justify this choice in particular circumstances. Nothing appears to prevent such an approach being used for this line contingency issue.

Again, it is very difficult to comment on this issue any further as PWC has not worked with EAL in designing its proposed islanding or contingency management schemes for this line, despite our continual requests for this consideration during the last 18 months. PWC inform us that a scheme is being designed but we have no information of when we will be able to see it or comment on how it is proposed to work. We therefore have no ability to comment on the materiality of the line contingency issue.

However, EAL notes that no comparison appears to have yet been made of the economic benefit of providing additional FCAS (in whatever form – battery or spinning reserve), north of Channel Island, compared to curtailing generation south of Channel Island that has zero marginal cost to the market. It is self-evident that such a comparison needs to be made prior to making a decision to curtail solar generation that is of zero marginal cost to customers, to the benefit of other sources of generation which have a significant marginal cost to customers.

**Battery Considerations**
EAL notes that no specific mention is made of the treatment of batteries in this document. It would be helpful if an outline could be provided of expected battery commitment and dispatch decisions, both when charging and discharging. Also, whether batteries will have to comply with Clause 3.3.5.17 of the Network Technical Code, on top of providing their other services such as FCAS and if so, how they are expected to do that.

**Forecasting Performance**

EAL note that PWC will be forecasting the output of "behind the meter" solar systems in the DKIS. EAL notes that PWC knows exactly where all these systems are located and has access to all the satellite based forecasting tools that it suggests are available to generators for capacity forecasting.

EAL suggest that PWC should publish the ongoing accuracy of their forecasting tools with specific comparison to the accuracy they require of generators in the Generator Forecasting Compliance Procedure. We believe this will educate the conversation about whether this procedure is either necessary or possible to comply with unless providing 0 MW forecasts.

If you have any questions on this submission, please contact Antony Piccinini at +61 400 345455. We are pleased to be a part of the transition to renewable energy in the Northern Territory.

Yours sincerely,

Simone Rizzi
Commercial and Renewables Manager