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Utilities Commission NT
Level 8, TIO Building
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Via email: Utilities.Commission@nt.gov.au

Dear Utilities Commission,

Submission on Draft Decision – Proposed Amendments to Codes – Generator Performance Standards

1. Executive Summary

Eni Australia Limited (EAL) thanks the Utilities Commission for the opportunity to provide a submission relating to its Draft Decision on proposed Generator Performance Standards (GPS), dated 4 December 2019. While EAL is generally supportive of most of the proposed changes (detailed comment on each clause is provided in the Appendix), we hold particular concerns around the requirements for forecasting accuracy from solar farms, on the following grounds:

- risks to power system reliability and quality of supply;
- unacceptable impact on existing investments;
- lack of adequate grandfathering provisions;
- economic inefficiency;
- introduction of barriers to market entry and to the desired energy transition; and
- significant ultimate cost to consumers.

In this submission, EAL has presented an overview of who we are, our history in the Northern Territory (NT), the impact of the forecasting accuracy provisions and how we believe they should be considered in light of issues the Utilities Commission must have regard to. We also suggest an alternative method that we believe would actually improve power system reliability (rather than just maintain the current level), at much lower cost than this proposal, noting that other options also exist.

2. Introduction

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, 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. These projects are currently under construction.

EAL has reviewed the Draft Decision of the Utilities Commission on the proposed changes to the GPS by Power and Water Corporation (PWC) and has prepared this submission in response. EAL's feedback is primarily related to the forecasting accuracy requirements of the proposed GPS (in this case, the forecasting accuracy requirements in Clause 3.3.5.17 as an automatic access standard) and is broken down into five main parts, as follows:

1. an assessment of the impact of the forecasting accuracy requirements of the proposed GPS on existing investments in the NT;
2. a discussion of the impact of the lack of grandfathering provisions on EAL, having already taken final investment commitments on three different solar farms in the NT, with aggregate 45 MW_{AC} of capacity and expecting to complete commissioning of the 25 MW Katherine Solar Farm before these proposed changes to the GPS come into effect;
3. an overview of the aims of forecasting and the benefits / costs of different forecasting options and alternative solutions to the same issues;
4. a discussion of how the forecasting accuracy requirements of the proposed GPS relate to the issues the Utilities Commission must have regard to under its governing Act;
5. a proposed way forward.

While other issues associated with the proposed GPS are also relevant, they are not as important by comparison. As a result, this submission focusses on the forecasting accuracy requirements of the GPS and their likely consequences. However, feedback on the remaining pertinent issues is also presented in the Appendix.

3. Impact on Investments

At the time of writing, EAL has announced final investment decisions and the award of engineering, procurement and construction (EPC) contracts for the following facilities in the NT:

- Katherine Solar Farm (33 MW_{DC} / 25 MW_{AC}, with a 5.7 MVA/2.9 MWh Battery Energy Storage System (BESS)) – construction is nearly complete and commissioning is underway;
- Batchelor Solar Farm (12.5 MW_{DC} / 10 MW_{AC}) – construction and site works have commenced;
- Manton Dam Solar Farm (12.5MW_{DC} / 10MW_{AC}) – construction and site works have commenced.

This represents a combined total of 45 MW_{AC} of solar farms. All of these facilities are supported by Power Purchase Agreements (PPAs) with Jacana Energy. The commercial terms (including the price) for these PPAs were negotiated prior to the requirements of this proposed GPS entering the public domain. EAL notes that during this time period, PWC have proposed a number of potential GPS modifications in the public domain, such as ramping and various methods of forecasting / accuracy requirements, which have typically faced overwhelming negative feedback from stakeholders, typically on the grounds of economic inefficiency.

During this time, EAL's view was that PWC's GPS proposals clearly required more work and stakeholders could rely on the regulatory oversight process to deliver outcomes that were more in line with standards, were economically efficient and that took into account the feedback from stakeholders. In the unlikely event that did not happen, EAL's view was also that, in accordance with good regulatory practice, existing investment decisions would be grandfathered from the requirements of any new GPS, particularly given the scale of the proposed impact on committed solar projects. However, to our genuine surprise, this has not occurred in the Draft Decision.

The financial impact of the proposed NTC Clause 3.3.5.17 requirements on forecasting accuracy is estimated by GHD to be $10M for a 25 MW_{AC} solar farm, in order to purchase the required 20 MW/10 MWh BESS to prevent pre-contingent curtailment. We have no reason to disagree that this scale of investment will be required to meet the provisions of the proposed GPS, as the cost of curtailment is likely to be significantly higher over the life of a solar farm. However, no consideration appears to have been given to the fact that further investments will be required on an ongoing basis to maintain this level of support, due to ongoing BESS degradation. Furthermore, additional operating costs will be required to maintain the BESS.

In EAL's experience in acquiring BESS systems, this estimate is only for direct equipment cost and it excludes owner's costs in the order of 15% (contracting and development costs, project management, legal review, design reviews, approvals, etc). This means that for EAL's 45 MW solar farm portfolio in the NT, the upfront cost of complying with the GPS provisions would likely be over (45 ÷ 25 x 10 x 1.15 =) $20M, which excludes the recurring cost of remediating ongoing BESS degradation. While BESS costs may possibly fall in coming years, there is no certainty that will happen and they have appeared slow to fall in recent years, in contrast to many projections. Also, in addition to these costs, the cost of lost production through round-trip losses in unnecessary charging and discharging of so many BESS on the DKIS does not appear to have been considered.

This figure is in overall alignment with some of the figures from consultants (GHD and Entura) but EAL is concerned about some statements in PWC consultation papers (eg June 2019, Section 3.7.1), for example suggesting inverter capacity can be shared between batteries and solar farms. This is not the case. EAL has also noticed the use of the term "asynchronous" to describe inverter connected generators, which is a term used to typically describe rotating equipment that does not operate at synchronous speed, such as induction generators / motors. EAL notes the Commission has adopted the term "non-synchronous" and agrees this is better terminology.

While the proposed regime also allows for negotiated rather than automatic access standards, the reality is that generators have very little leverage in these negotiations. PWC would only be required to provide reasons to reject proposals from generators, at its absolute discretion. We note that, in its most recent submission to the Commission, PWC strongly defends this discretion and appears to consider the automatic access standard and negotiated access standard as effectively equivalent. As a result, the only solution is to ensure the automatic access standards are fit for purpose in the first place which, as proposed, they are not.

4. Grandfathering Provisions

NTC Clause 12 specifies a cut-off date for application of version 3 of the code of 1st April 2019. Generators connected after that date must transition to the new version 4 of the NTC over a period not exceeding 13 months. No justification has been given for the choice of a date that triggers a clear negative impact for all solar projects that are not yet connected but are fully committed and under construction, which would be unprecedented in the regulatory environment in Australia. EAL is exposed to this risk more than any other stakeholder in the NT power system, owning over 80% of the capacity currently under construction. In the Draft Decision, it is suggested the cost of compliance with NTC Clause 3.3.5.17 (over $20M in EAL's case), is "reasonable". We refute this assertion in the strongest possible terms.

The typical approach for regulatory changes of a technical nature across Australia that imply a significant economic cost (such as this one), is for existing assets and investment decisions to be grandfathered under existing rules, with the new rules applying to new investments. Unfortunately, such a principle has not been upheld in the Draft Decision. While PWC have previously presented a variety of very costly proposals for this issue (including output ramping), EAL took comfort from the independent regulatory oversight in place in the NT to temper these potential demands and defend the interests of consumers. EAL was therefore genuinely surprised when this did not occur in the Draft Decision.

While EAL has strong concerns about the economic and technical inefficiency of the proposed GPS, as outlined in this submission, our main concern is that already sanctioned and committed projects are not being grandfathered, without justification. This precedent would create a degree of regulatory risk which will significantly raise the cost of capital for new renewable energy investment in the NT, a form of energy generation that relies on a low cost of capital, thereby creating an additional unnecessary barrier to market entry.

This has been a consistent message from all industry stakeholders in the renewable energy industry throughout the consultation processes. EAL is concerned that the Draft Decision appears to ignore these implications.

5. Forecasting Accuracy Requirements - Implications

In the context of the DKIS, $20M (upfront, plus recurring and ongoing costs) is an extraordinary and unreasonable amount to require EAL to spend on top of its existing investments on ensuring half hour forecasting accuracy, as similar levels of investment could result in far greater outcomes for the reliability of the power system. EAL notes that the same amount spent on BESS facilities spread around the Darwin ring main would buy the same 36 MW / 18 MWh facility that could, for example, also:

- serve to provide for the approximate entire spinning reserve needs of the DKIS, allowing the existing generation fleet to run fewer operating hours overall at much greater thermal efficiency and reliability;
- provide black start services to the DKIS, to reduce step loading on the existing generation fleet when individual feeders are placed back into service, a critical feature as seen in the recent Alice Springs system black event;
- provide voltage and frequency contingency support services following a line outage on the single circuit transmission line between Channel Island and Katherine. BESS systems located at our solar farms will instead be "behind" these outages and therefore useless in this event;
- provide voltage, frequency and synthetic inertia support services in addition to the production from our solar farms, whereas the methodology of the proposed GPS will most likely result in the BESS capacity being dispatched when the respective solar farm output is reduced, regardless of the needs of the power system at the time. For example, the combined output of a 20MW BESS located at our 25MW Katherine solar farm, can only ever be 25MW (the capacity of our connection point to the network), whereas if the BESS

was located and treated separately from the solar farm, then the combined output of the same equipment could be 45MW (20MW+25MW) at any one time, a much more efficient and effective outcome for the power system;
- provide all these power system services for 24 hours per day (BESS serving a solar farm is necessarily unutilized outside of daylight hours).

The economic benefits to electricity consumers from all these additional features would add up to many millions of dollars per year. These benefits are being ignored in the current proposal.

EAL notes there is nothing in the design of the proposed GPS that prevents EAL from sub-contracting forecasting accuracy services from centralized BESS systems that could have all of the above advantages (if they were paid for, which is not the proposal). However, doing so would not be in EAL's best interest, as EAL would either be completely reliant on third parties for providing forecasting accuracy services (with the resulting risk of pre-contingent curtailment resting only with EAL) or it would have to develop (identify available land, seek approvals, negotiate Generator User Agreements (GUAs) etc) alternative locations for this infrastructure at much greater cost.

Under this proposal, individual generators are strongly incentivised to co-locate the required BESS systems on their own facilities and reserve them exclusively to provide forecasting services, in order to hedge against the extreme risk of pre-contingent curtailment. This "turns off" all the other services this infrastructure could provide the power system if centrally controlled (including at night) and enabled to instead firm up aggregate forecast error (the sum of all forecast error on the power system including all solar farms, together with behind the meter (rooftop) forecast error). This is a highly inefficient outcome.

Nevertheless, EAL recognises the benefits of forecasting the output of renewable energy plant to the System Controller. We therefore do not oppose the provision of a capacity output forecast. However, there is no need for the output forecasts of individual solar farms to be accurate over a half hour period. The important factor for the System Controller is the accuracy of the *aggregate* forecast from all solar plants, including both behind the meter facilities and from solar farms, together with load forecasts. It should be noted that equivalent inaccuracies from forecasted production from conventional plant are managed through C-FCAS / spinning reserve, rather than the provision of a firm half-hour ahead forecast.

In the recently published System Black report for Alice Springs by Entura (section 4.6) EAL notes that spinning reserve is recommended to be held for either:
- severe reduction in solar output from a single solar farm (Uterne); or
- tripping of a single generator (a contingent event);

but not both at the same time.

It is not considered reasonable to plan for both these events to occur concurrently. This is presumably because the likelihood of the two events occurring together is equivalent to the likelihood of two generators tripping (two contingent events occurring concurrently), a situation for which it is well understood that load shedding is an acceptable management strategy (as it is a very rare event).

EAL believes this same control philosophy should also apply to the DKIS. No evidence has been provided in any of the consultations that this wouldn't result in acceptable power system reliability if the rest of the DKIS generators were being operated in a manner that is consistent with good electricity industry practice. The fact that conventional plant experienced an unacceptable 98 trips in a single year (according to the PWC consultation papers) is a strong argument for that plant to be modified / renewed to an acceptable level of reliability in accordance with its Generation Licence obligations. It should not be a consideration in this process as this has the potential to reduce pressure on the incumbent generators to bring their plant up to a level of reliability that is consistent with good electricity industry practice.

In addition, according to its submission PWC has not yet developed a forecasting system for behind-the-meter installations, despite those installations exceeding 50 MW of capacity already. If 50 MW of completely non-forecasted, rooftop solar capacity is currently being accommodated on the DKIS, it would seem prudent to first test the capability of forecasting technologies to provide sufficient information for the System Controller, prior to requiring all commercial scale solar farms to provide firm, half hour ahead forecasts. This proposed GPS mandates private sector solar farms to implement a very expensive solution without even testing the ability of normal forecasts to provide the required reliability requirements first, when aggregated together on an interconnected network.

The models used by PWC and referenced in the Draft Decision (NTC Clause 3.3.5.17) to justify the requirement for forecasting accuracy have not been provided in the public domain or even been provided to the consultants of the Utilities Commission in source form. They are therefore un-validated and appear to be:

- based on an assumption that very high levels of solar generation are inevitable (120 MW): this is far from proven for commercial and market reasons. PWC appear to be basing this assumption on a large number of connection applications they have received for solar farms, whereas it is well known in the industry across Australia that the number of connection applications received by Network Service Providers (NSPs) bears little resemblance to the number of eventually constructed facilities. No consideration has been given to a potential outcome that no more solar farms may be built. This could become quite a likely outcome if this proposed GPS is implemented in its current form;
- based on models of cloud cover and geographic distribution that are unknown and may not be suitable;
- appear to assume no governor response from the existing generation fleet, when a much cheaper solution is likely to be to ensure the existing fleet does respond appropriately to these events through proper governor tuning in light of suitable dynamic modelling of the power system (including with reduced inertia);
- do not appear to take into account all the alternative solutions for the same problems, including the ability of cloud forecasting services (without firming via BESS for half an hour ahead), centrally operated by the System Controller, to provide equivalent services that may be adequate for the aggregated power system. Or for a (much smaller) central BESS (or multiple units spread across the Darwin ring main) to only deal with the aggregate forecast error from all solar facilities on the DKIS, as well as all the other alternative options mentioned in this submission.

As a result, EAL has no confidence in the modelling provided by PWC to support their changes to NTC Clause 3.3.5.17.

6. Issues to which the Utilities Commission must have regard

EAL present the following comments on the forecasting accuracy provisions in relations to the issues that the Utilities Commission must have regard to, in accordance with the *Utilities Commission Act 2000* (NT).

In addition, EAL is concerned that, following its own previous consultation process, PWC does not appear to have taken into account the nearly universal feedback from industry and other stakeholders in opposition to these provisions,. If a consultation process receives such firm and consistent opposition, which has not changed over time, this must be properly considered and alternative options properly explored.

To promote competitive and fair market conduct

EAL considers the proposed GPS to be anti-competitive in favour of incumbent generators. It imposes a forecasting obligation on renewable energy plants that has no equivalent on conventional plants. When conventional plants do not meet their forecast (via unplanned outages - which has happened 98 times in the 2017-18 year as stated in the Draft Decision), they are able to call upon shared spinning reserve / C-FCAS, which all generators (including renewable generators) have to fund for them. Inversely, when a renewable generator does not meet its forecast it must spend tens of millions of dollars in batteries (in our case) or suffer up to 80% pre-contingent curtailment (loss of revenue) going forward.

While a renewable energy plant is also capable of experiencing unplanned outages, the frequency of such events for solar farms is much lower than for thermal plants meeting standard reliability requirements, and even more so in comparison to the existing generation plant on the DKIS and it therefore cannot be considered equally.

The proposed procedure in the Draft Decision for PWC to specify the level of curtailment according to the accuracy of solar forecasts also leaves generators at the mercy of PWC in a potentially very one-sided negotiation, where they have no recourse. It cannot be relied on to deliver efficient outcomes for the power system and its customers. Stakeholders such as EAL rely on independent regulation for this.

The forecasting provisions of the GPS therefore have the effect of preventing competition by increasing both the cost of capital (due to the lack of grandfathering) and the amount of capital for renewable energy development (due to the forecasting accuracy requirements). This has the effect of favouring the interests of the existing generation fleet, which is predominantly government owned.

To prevent misuse of monopoly or market power

Monopoly Network Service Providers and Network Operators hold considerable power to constrain and/or curtail generation, at very considerable cost to the owners of these facilities. Additionally, there is no real incentive for them to minimise such costs, as it is in their interest to just maintain as reliable a power system as possible at almost any expense. The cost of doing so is borne by the market and ultimately electricity consumers, at no cost to the Network Operator itself.

This risk averse approach attempting to avoid all possible risk of outages from renewable variability imposes very significant financial burden on investors such as EAL and prevents opportunities for new generation. The drivers behind such a risk averse approach to operating the network may by understandable in the context of such a low level of reliability in the existing generation fleet.

However, the lack of reliability of the existing conventional plants should be fixed by the owners of that plant, in accordance with their Generation Licence obligations and applicable regulations. It should not even be a consideration in this proposed GPS. Making renewable energy plants extremely reliable at extraordinary cost will not make up for the pre-existing lack of reliability. The core problem is the conventional plants and the most cost effective solution is for that problem to be fixed at source.

The Utilities Commission should be focused on the cost to electricity consumers of this proposed GPS and it should be comparing that cost against all the other options to achieve a reliable power system. It is our view that it has failed to do this in the Draft Decision. If continued, this failure would facilitate the misuse of monopoly power by PWC to avoid any costs of its own or for the existing (largely government owned) generation fleet, regardless of how much more cost efficient that may be for consumers, or how much more reliability it would create in the DKIS. The Utilities Commission should therefore not allow this misuse of monopoly power to go unchallenged.

To facilitate entry into relevant markets
We have demonstrated additional investments in the order of tens of millions of dollars would be required to meet the forecasting accuracy requirements of NTC Clause 3.3.5.17. It is self-evident that this cost, together with the increase in the cost of capital required to account for the severe commercial under-performance of existing solar investments in the DKIS, will heavily constrain the ability for renewable power generation to enter the NT power market.

It should be noted that this BESS cost is not representative of the “true cost” of solar farms. It should instead be viewed as a very expensive option to achieve a reliable power system with increasing solar penetration. The focus should instead be on some of the much cheaper options to establish the “true cost” of solar.

If it continues to ignore the actual “true cost” of solar in this manner, the GPS will unreasonably restrict the entry of solar farms into the DKIS market, an issue that the Utilities Commission should have primary regard to.

To promote economic efficiency
Throughout the consultation process run by PWC and the Draft Decision, there has been no reliability standard or Value of Lost Load (VoLL) provided to assess different technical solutions to solar variability for their economic efficiency. Economic choices to improve power system reliability can only be properly made in the light of benchmarks such as these, as occurs in other jurisdictions (NEM has VoLL, WEM has a reliability standard).

Under the proposed GPS, individual solar generators would deploy BESS infrastructure on their own solar farms to only provide forecasting services. This is highly inefficient for a number of reasons already mentioned,(as it ignores all the other benefits this infrastructure could also reliably provide, and as it will be doing nothing for the 12-14 hours of every day when the sun is not shining. This is a very significant opportunity cost when this infrastructure, if its control system is properly designed and coordinated, could be providing highly valuable power system quality and reliability services for customers (eg FCAS, C-FCAS, voltage support, synthetic inertia, load rejection / network outage support, black-start support to reduce the duration of system black events if centrally located, among others).

In addition, no assessment has been made of the ability of various alternative measures to achieve the same reliability outcomes at much lower cost. Or, viewed another way, the ability of these alternatives to impose the same cost on the market with much greater outcomes and consequent benefits to consumers. These include:

- *Aggregate forecasting:* forecasting that, instead of focusing on the accuracy of forecasts from individual solar farms, focusses on the accuracy of the combined forecasts of all solar generators, including both solar farms and behind-the-meter facilities, which are currently ignored despite totalling 50 MW of capacity. Only the remnant forecast inaccuracy would then be dealt with via battery support to the extent it is found to be required. Otherwise, under the current proposal the battery on one solar farm will at times be charging because production is above forecast, while the battery on another solar farm will be discharging because production is below forecast, and both will be ignoring the needs of the power system at the time. This is a very inefficient outcome, with risks to the stability of the power system due to “fighting” control systems. Dealing with aggregate forecast error recognizes the benefits of interconnected power systems instead, as it is the aggregated demand / supply balance that is actually important for power system reliability and control. Total BESS capacity can then be reduced overall and its capacity consistently controlled, rather than being setup for individual BESS to “fight” each other.
- *Existing plant upgrades*: improvements in reducing the minimum stable load of conventional plants, tuning governor controls to accommodate reduced inertia and other remedial upgrades to deliver greater reliability from the existing fleet and/or early retirement of sub-standard generation and replacement with new generation that is fit for purpose and able to accommodate significant changes in output. It is clear that the cost of improving the governor response of existing plant is likely to be minor in comparison to the costs being imposed on solar generators through this GPS but this option hasn’t even been considered in the documentation provided to date, despite its likelihood to yield much greater overall power system reliability compared to merely improving forecast accuracy from individual solar farms.
- *Dispatch changes*: no economic models have been provided to industry stakeholders to help assess the alternative cost of modifying the economic dispatch / merit order of generators on the DKIS to reduce the aggregated minimum stable loading of existing plant and/or improve the ability of the generation fleet to follow variable loads. While PWC claim to have done some modelling of various options, there is insufficient detail for EAL, or anyone else, to comment. Source data should be provided to stakeholders to conduct these calculations for a genuine consultation process to be undertaken. In addition, PWC have suggested that low system inertia requires a steam turbine to always be dispatched. In our view, a power system should be perfectly capable of stable operation using only gas turbines or reciprocating engines with significant solar input as there are plenty of global examples of this. If these plants cannot maintain reliable

frequency and/or voltage control, then there is a problem with their governor tuning being unsuitable for the available inertia – it is not an inherent problem with the technologies involved or a cost that should be considered the responsibility of solar farms to solve.
- *Stepped regulation*: there has been no consideration of the ability for existing, committed solar farms (such as EAL's solar farms) to benefit from the existing levels of spinning reserve on the system, with greater levels of power system costs to only be imposed on subsequent plants if they cause greater FCAS or C-FCAS costs on an aggregate level. While PWC do not wish for forecast error from solar farms to be able to call on spinning reserve, the reality is that the likelihood of a significant aggregated forecast over-estimate coinciding with a contingent event is equivalent to the likelihood of two contingent events occurring concurrently. Unless network operating requirements are also to be changed to an n+2 (spinning) regime, then a much higher reliability standard for solar farms can only be viewed as excessive by comparison.
- *Faster starting of conventional plant*: the current proposal by PWC appears to assume a worst case scenario of accommodating very slow starting units in the DKIS (requiring 30 minutes to start). Some reciprocating engines and other generators allow for much faster start-up and synchronisation, and they should be utilized. The much lower cost of retro-fitting faster starting capabilities in the existing generation fleet, or changing the dispatch order to utilize units that do start quickly, appears to have been ignored here. If necessary, the cost of deploying a new fleet of generators with fast start capability (sub 5 minute), low minimum loading levels, excellent (>60%) step load capability and higher thermal efficiency than the existing fleet should also be properly considered as this cost is likewise likely to be lower than the current proposal, if considered together with the economic benefit of retiring incumbent inefficient, slow starting and unreliable units.
- *Alternative measures to control voltage, frequency and synthetic inertia*: a detailed static and dynamic model of the power system (which is unavailable to EAL) is required to investigate alternative measures in any detail, but in general they may include BESS equipment located at particular substations for regulation FCAS and/or voltage support in addition to C-FCAS (spinning reserve), synthetic inertia, behind the meter production firming, black start assistance and other system benefits on top of dealing with aggregate forecast error. Such systems can only be properly specified and designed with detailed dynamic (EMT) models but it is clear to EAL that if this was done, the result would be much cheaper and/or more cost effective than the current proposal.

To ensure consumers benefit from competition and efficiency
Alternative measures to improve power system reliability at similar economic cost would have demonstrable benefits for consumers. For example, to take the idea of batteries spread across the Darwin ring main, these batteries could instead be located and centrally controlled to provide additional system support services, such as:
- black start, including moderating the impact of network switching to within the step-load capability of existing generators and reducing the duration of "system black" events as a result;
- FCAS and C-FCAS / Spinning Reserve – the size of the required battery for EAL's solar farms is equivalent to the amount needed to carry the entire spinning reserve of the DKIS. The economic benefit of using the battery in this capacity is very significant but will not be realized under this proposal;
- voltage control through the provision of both real and reactive power to support voltage, as required at the time. This is in addition to the voltage control able to be provided by

the relevant solar farm, instead of substituted if the BESS is installed behind the meter of the solar farm, as is likely to be the outcome here;
- maintaining power system stability after large network outages, such as loss of the line between Channel Island and Katherine. Multiple BESS on-site of our solar farm facilities, for example, will be useless in the event of an outage of this nature.

All these consumer benefits are real and verifiable for customers in the Darwin area and the ability for this level of battery investment to provide these services for customers is prevented by the proposed GPS, where this battery capacity will instead be reserved purely for improving the forecasting accuracy of individual solar farms and most likely located at those solar farms, instead of at more beneficial locations on the DKIS.

To protect the interests of consumers with respect to reliability and quality of services and supply in regulated industries
It has already been pointed out in this submission how alternative measures can be used at lower cost to improve power system quality and reliability. Instead, this proposal uses forecasting accuracy to merely maintain the poor level of existing power system reliability at great expense, in terms of both risk to committed industry stakeholders such as EAL and increased capital costs for unnecessary and poorly utilised battery capacity.

7. Proposed Way Forward

We note a number of requests from interested parties for EAL's view on what should happen in the event that the capacity forecasting accuracy provisions of the GPS are rejected. Firstly, we wish to point out that solving the problems of operating the DKIS is not our role, or the role of the Utilities Commission. It is merely sufficient to point out that this proposal is highly inefficient and likely to be counter-productive and request the parties responsible for the operation of the market and power system propose a more efficient and fit-for-purpose solution that doesn't have such severe impact on the issues that the Utilities Commission must have regard to.

However, we make some suggestions below on EAL's view of a more balanced and effective way forward.

In EAL's view, it is particularly important for system security and cost efficiency that BESS infrastructure installed on the DKIS be jointly controlled in a consistent manner and not be set-up so one BESS ends up "fighting" the control actions of another. This runs the risk of setting up the type of counter-productive control system action that contributed to the system black event in Alice Springs (for example) and which could have similarly unintended consequences in the DKIS. Rather than merely trying to correct the solar forecast inaccuracy of individual solar farms, all BESS infrastructure should be co-ordinated and controlled in a consistent way that supports aggregated power system outcomes as a whole, including both aggregated forecast error and other benefits like black start assistance, generation or network contingency support, voltage support or synthetic inertia, among others.

Therefore, we believe that centrally controlled forecasting by the System Operator of all behind-the-meter solar facilities, together with all solar farms, is required. To facilitate this, EAL is happy to provide its own forecasts from its own facilities on a "best endeavours" basis (or consistently with similar requirements in the National Electricity Rules).

As solar output in the DKIS grows, additional BESS infrastructure can be centrally contracted as required to accommodate forecast error. It is already clear that the existing FCAS charge currently being paid to Territory Generation by other generators, if it could be turned into a secure revenue stream for a sufficient period of time (eg 10 years), would be more than sufficient to result in a level of centrally controlled BESS investment that would cover both:

- the existing FCAS and C-FCAS (spinning reserve) requirements of the DKIS (most Australian jurisdictions model the cost of spinning reserve at approximately $100k/MW/year, which means BESS systems are already very competitive); and
- the future requirements caused by aggregated forecast errors from all solar facilities (both “behind” and “in front” of the meter).

The precise location/s of this BESS infrastructure should be educated by detailed static and dynamic / EMT modelling of the DKIS to identify locations where they would provide most benefit in terms of voltage and frequency support under network contingency events and the provision of ancillary services such as black-start services. This may result in a spread of locations for the infrastructure across a number of substations or power stations.

Some jurisdictions favour the establishment of FCAS / C-FCAS markets for these services. However, this would not appear to be “fit for purpose” in this case as it does not provide a secure revenue stream for a BESS proponent (the cheapest provider of these services) and the very small size (and high level of government ownership) of the DKIS market will result in a lack of confidence in ongoing revenue for any independent BESS proponent.

As both the System Operator and the owner of the relevant substations, PWC appears best placed to run such a tender, however it has a strong implicit incentive to over-specify the required BESS capacity in order to operate the power system as conservatively as possible, at the ultimate expense of electricity consumers. Therefore, the sizing of the required BESS to cover all of the required FCAS, C-FCAS and forecast error services needs to be properly studied, with those studies subject to regulatory oversight by the Utilities Commission to ensure it is consistent with the aims of its Act. In particular, these studies need to be informed by a stated reliability standard (or VoLL) so that there is a known level of reliability that is accepted by all stakeholders, as per the approach in other jurisdictions.

It should be noted that due to the $/MWh structure of this tariff, as solar production increases on the DKIS and more BESS capacity gets deployed to manage forecast errors (as well as conventional FCAS and C-FCAS), solar farms will pay a suitably increasing share of this cost. This appears to be a fair outcome for all participants, by both providing an efficient level of BESS investment in the first place, together with a greater proportion of it being paid for by solar farms as their production grows. It should also be pointed out that this (appropriately sized) BESS infrastructure will then be able to also provide much greater power system reliability and services for the 12-14 hours per day when the sun does not shine, which would not be the case under the current proposal.

To the extent that interim measures need to be implemented as we transition to arrangements like these, current requirements can be met either by using:

- existing spinning reserve from the generation fleet (with governor tuning provisions to accommodate reduced system inertia, if required); or

- modifications to the dispatch order to dispatch units with greater operating range (e.g. lower minimum loading, faster response) when loads are low and solar production is high.

If solar farm deployment grows, PWC can request approval from the Utilities Commission for more BESS capacity to cover any increased aggregated forecast error. In the meantime, the above temporary measures are at their disposal.

EAL believes it then becomes self-evident that the overall economic efficiency and power system reliability outcomes of this type of proposal would be far superior to the current solar forecasting accuracy proposal by PWC. However, we are mindful that there are also other alternatives and choosing between them is not the task of the current consultation process. It is merely adequate in this case to revert the forecasting accuracy provisions in NTC Clause 3.3.5.17 to those currently in place in the National Electricity Rules and recommend to PWC (and government) that more efficient alternative arrangements be put in place, with the above mentioned interim arrangements being implemented until then.

8. **Conclusion**

In conclusion, we wish to re-iterate that while EAL maintains that the forecasting accuracy provisions of the proposed GPS are very costly, inefficient and ineffectual, our primary concern is the burden they represent to our significant investments in the NT, given the lack of grand-fathering.

To be specific, EAL is particularly concerned about the grand-fathering of the forecasting accuracy provisions of the proposed GPS, due to its significant commercial sensitivity, as explained in this submission. The remainder of the proposed GPS, subject to our comments provided in the Appendix, can be complied with in its proposed form. EAL note that a number of potential GPS changes (e.g. ramping) have been proposed during the time period we have developed our solar farm projects. We have relied on independent regulation to deliver outcomes that are consistent with the goals that the Utilities Commission must have regard to under the *Utilities Commission Act 2000* (NT). In our view, the current forecasting accuracy provisions of the GPS are in opposition to these goals and we urge the Utilities Commission to take into account the relevant considerations set out in this submission.

We also note that it is not the job of Generator Performance Standards to ensure a power system has adequate supply of capacity, energy or storage going forward. If a shortfall of capacity, for example, presents itself in the DKIS, it is the proper task of government policy to provide the right market or structural incentives to fix. Using technical regulations to solve perceived failures or shortcomings of commercial or market arrangements sets a very dangerous precedent.

We believe both the Utilities Commission and PWC should instead conduct a genuine consultation process and properly consider alternative measures to improve power system reliability with greater solar input that have much lower cost.

If you have any questions on this submission, please contact Antony Piccinini at antony.piccinini@eni.com or +61 400 345455.

We are pleased to be a part of the transition to renewable energy in the Northern Territory. Please do not hesitate to contact us for further information.

Yours sincerely,

Ernie Delfos
Managing Director, Eni Australia Limited

Appendix

Commentary on the Draft Decision on proposed changes to the Network Technical Code by exception. Where commentary is not provided on a clause, EAL has no comment to provide.

Clause 3.3.4: Provision of Information
The provision of full EMT and RMS models to the Network Operator is reasonable and consistent with the approach in other jurisdictions. See also our response for Clause 3.3.5.

Clause 3.3.5: Technical Requirements
EAL endorses the principle that specific timeframes should be imposed on the Network Operator to accept or reject a negotiated access standard. 30 business days appears to be more than sufficient for this purpose and EAL does not understand PWC's request in their subsequent submission to remove this timeframe, as they already have the final say over negotiated access standards. Indeed, this approach only heightens our concerns about a lack of incentives for PWC to negotiate access standards in an impartial manner. Therefore, the Utilities Commission should not rely on this process to deliver positive outcomes for electricity consumers in the NT.

EAL also endorses GHD's proposed wording for this clause. Other jurisdictions require NSPs to publish public domain models of their models, with any confidential details redacted, to allow developers to conduct their own due diligence and optimization of the static and dynamic modelling of their proposed power station and its interaction with the network, without having to rely on the NSP for this purpose. This feature is critical to EAL and the absence of a proper system model has been a major impediment to work around for our investments in the NT.

It is clear that complete reliance on the Network Operator to have the only realistic model of the power system means:

- any mistakes in modelling by the NSP / Network Operator or its consultants will be at the expense of the developer and/or owner of the facility when static or dynamic issues present themselves in the real world on the physical infrastructure involved, potentially resulting in ongoing and indefinite pre-contingent curtailment of the facility for its operating life, at the full risk of the developer / owner;
- no liability is or will be accepted by the Network Operator for these mistakes;
- when a static or dynamic constraint is found, there is no incentive for the NSP to identify the most cost effective solution. The experience in other jurisdictions is that when NSPs conduct this work, very expensive solutions are often suggested, e.g. DVAR equipment, in order to get the generation proponent to pay to fix existing non-conformances in the network. This becomes a highly inefficient barrier to entry for generators;
- there is no ability for the developer to conduct its own modelling to identify more cost effective and simple solutions that may have been overlooked by the NSP / Network Operator, as the model is not available to them;
- it is not possible to conduct due diligence on this modelling using the developer's own resources. A complete reliance on work conducted by third parties, with no acceptance of liability for mistakes or negligence, is a very uncomfortable place to be for private capital and unnecessarily raises the cost of capital for these projects, at significant economic cost to electricity consumers in the DKIS.

Therefore, it is strongly recommended that effective reciprocal arrangements be put in place, either through this clause or elsewhere in the NTC, for the Network Operator to make available in the public domain an equivalent static and dynamic model of the power system in a commonly used format (e.g. DigSilent / PSS/E). This would enable the development of cost effective solutions to any issues first, prior to a simple and low cost verification of this solution by PWC using the complete model.

Ideally however, the full model should also be available to the developer's own consultants upon provision of a suitably executed Confidentiality Agreement with those consultants to protect the information. The option of allowing consultants to access the complete model, under appropriate confidentiality obligations, allows proponents to use trusted resources to conduct this work properly without themselves having direct or indirect access to any confidential or commercially sensitive information that may be available in the models. EAL is unaware of any reason that could prevent this from occurring, as these consultants are often used by the NSP directly in any case to verify these studies and most equipment manufacturers are comfortable with this approach.

This all impacts the proponent's ability to provide evidence in support of a negotiated access standard, as this evidence is typically only available to be seen through detailed modelling.

Clause 3.3.5.1: Reactive Power Capability
EAL appreciates the efforts that GHD and the Utilities Commission have gone to in order to provide the option for a negotiated access standard for reactive power provision, as it is important to prevent over investment of reactive power capability (and unnecessary costs for generators), where they are clearly not required.

It should be noted that these clauses were setup at a time when synchronous generators could supply significant levels of additional reactive power at marginal extra cost, so the implications of doing so were not onerous. However, if additional voltage support equipment is required, a solar generator has to source the same equipment as the NSP would (e.g. additional inverter capacity or capacitors), at the same cost, in either static or dynamic form as required. There is therefore no longer a real benefit to providing this capability all the time (regardless of whether it is required or not), compared to a NSP only sourcing it at locations where it is actually required.

EAL considers this automatic access standard as important and can see how it can be used as an attempt by an NSP to move costs it should be funding onto generation proponents. In many cases a lack of reactive power at a connection point has been a long-standing deficiency for an NSP they should have already fixed. Some generators may just choose to pay for these costs unnecessarily as they may form a reasonable view that it would be cheaper and easier to do so rather than go through the arduous, costly and relatively one-sided process of having to negotiate an individual solution for their (relatively small by industry standards) power station. It therefore becomes just another unnecessary cost of doing business in the NT and should be resisted on that basis.

To that end, the GPS should limit the ability of the Network Operator to reject a negotiated access standard if the reactive power deficit is not required or is a pre-existing condition of the network, rather than being caused by the connection of the Generator.

Clause 3.3.5.2: Quality of Electricity Generated
EAL endorses the Commission's proposed wording to allocate emission limits to harmonic distortion consistent with the Australian standard.

Clause 3.3.5.3: Generating Unit Response to Frequency Disturbance
Given that frequency movements on the DKIS are faster than the NEM, it is unclear why a stabilization time of 10 minutes is required. Some justification should be provided for such a long stabilization time as it may have the effect of endorsing poor governor function and consequent poor response of and instability from existing generators, due e.g. to time delays, which is behind recent proposed changes in the NEM as detailed in the following link: https://www.aemc.gov.au/sites/default/files/documents/mandatory_primary_frequency_response_-_draft_determination.pdf

Clause 3.3.5.4: Generating System Response to Voltage Disturbances
The definition of "normal voltage" proposed by GHD in this clause (with a range of ±10%) appears to double up on the function of 3.3.5.4 (a) (6), which already specifies a range of 90%-110% of what we assume is meant to be nominal voltage. If this is implemented as it stands it would appear to add another 10% on top of the 130% range in this clause, i.e. up to 143% of nominal voltage, with the same issue on the reduction of the lower range, which doesn't appear to be intentional.

EAL recommend this definition be reviewed and / or a definition of nominal (singular) voltage be provided instead, to be consistent with what appears to be the intent of this clause. We note PWC have proposed a definition for "nominal voltage" without removing the definition of "normal voltage", which doesn't appear to remove this problem of increasing the effective actual range to 143% of "nominal voltage".

If this effect is intentional, it should be checked against the HVRT and LVRT capabilities of common inverters for solar farms.

Clause 3.3.5.5: Generating System Response to Disturbances following Contingency Events
PWC make a number of claims in their submissions (including their submission of the 10th January 2020) for this clause regarding the inherent weakness of the NT power system and its predisposition to lightning and severe weather. The impact of these issues are impossible for other stakeholders to verify as we are not in possession of a dynamic model of the power system. It appears even the consultants of the Utilities Commission are similarly operating without the benefit of this model. In order to fulfill its role as an independent regulator, it is imperative that the Commission conduct its own, independent dynamic modelling to verify the materiality of these statements, as these issues can be exaggerated by risk-averse network operators and can result in potentially enormous and unnecessary costs to generators.

EAL is particularly concerned that the requirements the Network Operator is seeking here may not be capable of being met by both the inverters and BESS we have already purchased or indeed by any other commercially available inverter / BESS equipment. As a result, we request the Utilities Commission investigate this issue in detail.

In addition, we note that the Network Operator has a number of other tools at its disposal to maintain system security during severe weather and periods of high lightning activity, including temporary curtailment of solar farms. It appears to have ignored its own ability to manage the network during periods of severe weather when asking for capabilities that may be beyond the capability of solar farm inverters.

EAL endorses any approach that is both consistent with other jurisdictions (such as the NEM) and is within the capabilities of existing “off the shelf” equipment. To the extent that is the case with the changes proposed by GHD and PWC (and this can be verified), then they are acceptable. To the extent that leaves PWC with operational problems during periods of severe weather, then they should be managed by short term changes to the dispatch order during those periods to ensure the system remains stable.

Clause 3.3.5.8: Protection of Generating Units from Power System Disturbances
EAL endorses GHD’s view that these requirements can be met by solar plant but cautions that the specification of times to reduce output and / or disconnect should be supported by dynamic modelling of the power system as they may cause instability. These clauses appear to specify a de facto (and not necessarily fit for purpose) droop capability when actual droop curves should be selected following dynamic studies so as to maintain power system stability. Nevertheless, as an outer limit of capabilities, they appear acceptable, notwithstanding the ability of inverters to operate much faster than this in response to frequency excursions, which could assist a power system with reducing inertia and could be a desirable feature for all plant to assist the energy transition in the DKIS if co-ordinated with the other controllers on the network.

Clause 3.3.5.11: Frequency Control
EAL endorses the approach recommended by GHD for all generators, *subject to energy source availability*, to leave enabled a relatively tight droop response to frequency control. The precise selection of droop and deadband settings is dependent on the results of detailed dynamic modelling, however the range of responses specified here appear adequate to cover most requirements and appear to be consistent with the capabilities of the relevant technologies, notwithstanding the fact that in a system with reducing inertia, faster and greater response may become desirable to maintain system control at least cost.

EAL expects PWC’s interpretation of this clause to result in no pre-contingent curtailment on solar farms in the DKIS, whether under an automatic or negotiated access standard. Any imposition of such a requirement for FCAS or C-FCAS raise capability, should be compensated through a mutually acceptable payment for these services. It would be a positive step to include some commentary within the clause to that effect.

PWC’s subsequent submission of the 10th January 2020 includes a link to Clause 3.3.5.17. Consistent with our advice elsewhere in this submission, we believe this link should not apply.

Clause 3.3.5.12: Impact on Network Capability
As per previous advice in this submission, EAL does not have confidence in its ability to negotiate access standards with PWC from such a weak commercial position (where PWC is monopoly NSP, System Operator and Network Operator and also has conflicts of interest across those roles). We therefore consider the automatic access standards as the most

appropriate benchmark for consideration, as reliance on negotiating a reasonable access standard results in the emergence of these issues when commercial issues are at stake. This is further tightened up by PWC's stated desire in its submission of 10th January 2020 to further restrict the ability of proponents to negotiate.

In this case, EAL considers a generation project should be able to automatically proceed even if it reduces transfer limits, as long as the reduced limit does not impede the ability to supply customer load. No justification has been provided for removing this standard from the NER NT. It is EAL's view that network transfer capacity is there to be used and should first be used by loads and secondly by generators, in that order. If new loads, at a later date, eventuate that require modification to generator control system to release the transfer capacity that they have utilized, then NSPs should be required to negotiate suitable control system solutions with generators to do so, rather than the other way around.

At present, the operation of this clause could result in unnecessary and economically inefficient reservation of transfer capacity in the network that will most likely never be used by a load, at the cost of generators to "keep open" indefinitely. This could therefore become a significant barrier to market entry for new renewable energy generators.

Clause 3.3.5.13: Voltage and Reactive Power Control
EAL has no comment on the requirements for synchronous plant. For non-synchronous plant, the limiting value appear reasonable and within the capability of inverters, for example. Indeed, these settings may be able to be significantly accelerated if required in future, in line with those capabilities. But there is no need to mandate this capability into the NTC at this point in time.

GHD's proposed wording changes in part 3 (i) includes a requirement for continuously recording (without nominating for how long records must be available and without nominating the disturbance trigger point) key variables (which are undefined), including each input and output of the control system. EAL is unaware of equipment that could continually do this and the database of all this data during normal operation would be very large indeed, depending on the sampling frequency (undefined).

EAL therefore considers this recording requirement unreasonable and unworkable in the absence of far more information about how it is intended to operate. EAL considers it more reasonable that this level of recording infrastructure only be deployed by the NSP in response to identified problems / non-conformances on the part of the generator and that the generator should cooperate with NSP attempts to do so, although issues like this are typically resolved at a working level and don't appear to require specification within the NTC.

Clause 3.3.5.14: Active Power Control
EAL endorses GHD's recommendation to include the wording "subject to energy source availability" in this clause. EAL rejects any proposal to link this clause with the proposed clause 3.3.5.17. Attempts to do so only underline the all-encompassing and pervasive nature of clause 3.3.5.17 and only provide further grounds to demonstrate how unreasonable it is.

There is nothing unique about the DKIS that requires all generators to be "scheduled". The existence of 50 MW of rooftop solar already, with no forecasting at all, attests to that.

Clause 3.3.5.15: Inertia and Contingency FCAS
EAL endorses the approach for solar farms to supply C-FCAS lower services at all times, with no pre-contingent curtailment of solar farms to supply C-FCAS raise services in the absence of an ancillary services agreement that the generator has freely consented to. It is not entirely clear that this will be the effect of this clause as the option of partially loaded generation unit remains in the proposed wording and the wording "subject to energy source availability" does not by itself prohibit the Power System Controller / Network Operator from requiring generation units be partially loaded for this purpose.

EAL requests the wording of this clause be reviewed so it gives clearer effect to the intent expressed in the explanatory notes that no pre-contingent curtailment of solar farms to supply C-FCAS raise services will occur in the absence of an ancillary services agreement that the generator has freely consented to.

EAL likewise rejects any link to clause 3.3.5.17.

Clause 3.3.5.16: System Strength
While the proposed preparation of System Strength Impact Assessment Guidelines appears reasonable at face value, the reality is that such guidelines can have impacts that are very wide ranging and cut across a number of other clauses in the NTC. Also, if PWC are the only party in possession of the dynamic / EMT model of the power system, then the generation proponent is in a very weak position to identify cost effective technical solutions or negotiate a suitable access standard once these guidelines are developed.

EAL prefers a regime where these guidelines are a formal part of the NTC and are subject to the regulation and consultation requirements of the Utilities Commission. Of particular concern is the ability for them to be developed and imposed unilaterally by PWC. This is particularly relevant for the NT, compared to other jurisdictions, as PWC has so many inherent conflicts of interest in fulfilling the requirements of being Network Operator, System Operator, Power System Controller and NSP. External oversight of these conflicts of interests is therefore especially important, as applies to clause 3.3.5.17.

EAL does not understand any concern about undertaking reviews when the AEMO Guidelines are reviewed. A review does not have to be onerous if it quickly finds changes to the AEMO Guidelines have no application in the NT. This requirement helps ensure the NT keeps up with the necessary changes in all power systems to accommodate reduced inertia and accelerate control systems to enable the energy transition.

Clause 3.3.5.17: Capacity Forecasting
EAL's response to the provisions of this clause is outlined in the body of this submission. The Utilities Commission's proposed wording changes to PWC's proposal do nothing to alleviate EAL's concerns. EAL likewise takes no comfort from its position to negotiate an access standard with PWC, given the lop-sided relative commercial position of both parties to such a negotiation and the fact that PWC have maintained these capacity forecasting automatic access requirements in the face of such universal opposition from the industry. Our investments in the NT are reliant on independent regulatory oversight of this matter to ensure fair treatment.

Clause 12: Transitional Arrangements and Derogations from the Code
The grandfathering date (1 April 2019) in this clause has already been discussed in the body of our submission. The proper grandfathering date should be the date of entering into force of the new regulations, and grandfathering should apply to all projects that are connected or committed (e.g. are under construction or have taken final investment decision).

EAL endorses the approach of the Utilities Commission regarding the reimbursement of PWC costs for negotiating its own position.