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Via email: electricityreform@nt.gov.au

Review of Essential System Services Consultation Submission

Eni Australia Limited (EAL) makes this submission to the Design Development Team of the Northern Territory (NT) Department of Trade, Business and Innovation (DTBI) for the “Review of Essential System Services (ESS) in the Northern Territory’s Regulated Electricity Systems”.

1. Executive Summary

EAL’s core considerations for the Review of Essential System Services are:

- Review / repeal of the capacity forecasting provisions of the Network Technical Code as, in their current form, they represent a form of ESS that is far more costly than conventional ESS, potentially by an order of magnitude;
- Recognition that the cost of regulating reserve for aggregated solar forecast error across the DKIS is similarly far lower than the cost of the capacity forecasting provisions;
- A reduction in the conflicts of interest inherent in the market, primarily through the introduction of an independent Market Operator;
- Provision of sufficient resources to the Utilities Commission to enable it to independently regulate the market, rather than rely on consultants as appears to currently be the case;
- A transition from a power system reliant on high inertia to one able to operate on much less inertia, recognising the power systems around the world able to operate solely on aero-derivative gas turbines;
- Acknowledging the very high cost of ESS under the existing monopoly arrangements;
- The ability for private sector battery proponents to bid for a long term ESS contract for the DKIS, recognising that batteries are the lowest cost technology for most of these services and long term revenue certainty is necessary for investors to bring them into the market;
- Avoiding a situation where the battery being procured by Territory Generation has any preferential access to the ESS market, as well as their existing fleet, for competition reasons; and
- An acknowledgement that the requirements of the energy transition and the government’s renewable energy targets require a cost effective and fit for purpose ESS regime, in preference to trying to make the technologies of the future look like those of the past.



2. 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, 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. This project is about to commence compliance testing. In October 2019, EAL completed the acquisition of two further construction-ready 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.

3. Response to Issues Paper Questions

Question 1

(a) *Are there other context or developments relevant to the review that the Design Development Team should take into consideration?*

Limited reference is made to the Capacity Forecasting requirements of the System Control Technical Code (SCTC) and the Network Technical Code (NTC), which have introduced unacceptable curtailment risk to EAL's assets after final investment decisions were taken. EAL has made previous reference to these requirements in a number of submissions, which are available for download at <https://www.powerwater.com.au/market-operator/consultation-papers>. Our most recent submission is attached as an Appendix to this submission and contains many of the relevant points.

The requirements of these forecasting provisions are extremely costly and inefficient. In terms of introducing impediments to private sector investment, the issues in this paper overlap with the curtailment risk introduced by cl. 3.3.5.17 of the NTC and/or the extreme cost of complying with the *automatic access standard* of that clause. Procurement of ESS is a far cheaper and more reliable method of achieving the outcomes that the forecasting provisions claim to pursue, for the following reasons:

- The effect of the forecasting provisions is to introduce either an unacceptable loss of solar production to guarantee accuracy, or the installation of sufficient battery capacity to guarantee compliance, which is up to 100% of solar farm output for half an hour;
- Either one of the above options will make projects that have been already sanctioned uneconomic;
- In the medium to long term, the cheapest technology for both regulating and contingency FCAS raise (the most costly form of ESS) is a battery system;
- Under the forecasting arrangements, each solar farm would install its own battery, to ensure its own forecast accuracy, on top of the battery that will be the lowest cost provider of ESS. This will yield a far higher level of installed batteries on the DKIS than necessary;
- The use of ESS for aggregated solar forecasting errors (for both rooftop and utility scale installations), together with load forecasting error (regulating reserve) and contingency FCAS, would result in a far lower level of installed battery capacity across the DKIS, with far greater overall capital efficiency;
- This would also result in a more reliable power system as batteries used for ESS will be providing coordinated outcomes, rather than merely being used to firm up



individual forecast inaccuracies, where they could end up contributing to power system failures rather than helping to prevent them;

- It is therefore much cheaper and more cost effective to use ESS for this service, rather than requiring each solar farm to ensure their own forecast is accurate;
- This would allow both generator and load forecast accuracy to be properly shared among rooftop and utility scale generators in the same way that spinning reserve is traditionally shared among generators, making the most of the interconnected nature of the DKIS;

So a review of these forecasting requirements must be a central focus of any electricity market review, as there are much cheaper methods to gain far greater improvements in power system security within the energy transition, without stranding the investments of those who have financially supported new renewable energy investment in the NT, including EAL. In broad terms, it is not appropriate to transition to a new energy future by trying to make it look like the past.

The forecasting provisions are effectively a very expensive method of mandating ESS from renewable energy generators. A properly designed market for ESS would instead provide a significant improvement to power system security and reliability at much lower cost than the requirements of Clause 3.3.5.17 of the NTC.

(b) Is the approach to the review, which ties ESS market design principles back to the National Electricity Objective, appropriate?

Yes, the National Electricity Objective is a good starting point for market design.

(c) Are there other relevant matters which should be considered?

EAL has been exposed to unacceptable delays in commissioning and compliance testing of its Katherine Solar Farm due to constantly changing technical rules (eg to the NTC), as well as new technical requirements being regularly introduced from the System Controller. Technical requirements for compliance testing protocols have taken more than nine months to finalise, with new issues raised throughout the process and prolonged delays in reviewing documents that have only minor amendments to versions that have previously been reviewed.

In any review of ESS provision, it must be ensured that relevant industry bodies, for example the System Controller, have the technical resources required to perform their functions in a timely manner, without resorting to the use of consultants on a continuous basis. Consideration should therefore be given to the use of bodies who have greater technical and commercial resources at their disposal, as well as a better understanding of the technical issues associated with the energy transition.

Question 2

(a) The Design Development Team is seeking initial stakeholder views on appropriate ESS categories and definitions for the Territory's regulated electricity systems, to inform a draft proposal to be presented in the review draft report.

Noted.



(b) Is there a need to apply different ESS categories for Alice Springs and Tennant Creek than for the Darwin-Katherine system?

EAL has not given any consideration to the Alice Springs and Tennant Creek power systems, its feedback is solely focused on the Darwin to Katherine Interconnected System (DKIS). However, to be “fit for purpose”, ESS categories and markets should reflect the size of the relevant markets.

(c) Should the Territory's ESS framework require and empower the System Controller to develop and publish detailed specification/descriptions for each category of ESS? What, if any, regulatory prescription or oversight should apply?

Detailed specification and descriptions for each category of ESS are required for stakeholders to understand how the power system is operated and to give confidence to future investors that there are no unidentified risks.

The Northern Territory is unique in the Australian electricity industry in the number of potential conflicts of interest faced by the entity that performs the functions of System Controller. As far as EAL is aware, such entity is also:

- Wholesale provider of gas to the power generation market;
- Network Operator / Monopoly Network Service Provider;
- Owned by the NT Government, who also own much of the existing conventional energy fleet through Territory Generation, as well as access to retail customers through Jacana Energy; and
- Market Operator.

The potentially conflicted position of the System Controller is very concerning. This is particularly the case when rule changes like the capacity forecasting provisions of Clause 3.3.5.17 of the NTC discourage competing sources of energy from accessing this market, such as renewable energy. In this context, wholesale reform is preferable, such as introducing an independent Market Operator, as has previously occurred in Western Australia’s Wholesale Energy Market (WEM).

At the very least, this situation demands a strong degree of regulatory oversight from the Utilities Commission (UC), which needs to have sufficient technical resources of its own to provide effective regulation of the electricity industry. If this can’t be achieved, alternative regulators like the Australian Energy Regulator (AER) should be considered instead, who have the necessary technical and economic resources for the task. EAL notes that the AER has already taken over the economic regulation of the power transmission and distribution network owned by Power and Water Corporation (PWC).

EAL has formed this view because the resources available to the UC at present do not appear sufficient for it to deal with the demands being placed upon it. Technical rule changes proposed by PWC, such as capacity forecasting, do not appear to have been challenged, regardless of the EAL’s specific concerns regarding how inconsistent they are with the UC’s governing Act. EAL has provided detailed submissions to the UC as to why this is the case, but the substantive points have received no response. For example, the cost of additional



regulating reserve for aggregated solar forecast error across the DKIS has never been compared to the extremely high cost of storage required for each generator to meet the requirements of Clause 3.3.5.17 of the NTC, despite it being a clear question that any regulator must consider. This is particularly relevant in the DKIS where the level of spinning reserve is so high and additional requirements for regulating FCAS would only rarely impact contingency FCAS.

The UC also heavily relies on electricity industry consultants, many of which may face conflicting positions as they appear to also provide consultancy services to PWC. It has been difficult for EAL to obtain information on conflicts of interest issues throughout these processes, as there has been no disclosure by PWC, the consultants or the UC.

This is strong concern for EAL. In EAL's view, either the UC should be given the resources to effectively regulate this industry, or a suitably experienced electricity industry regulator should be used for the purpose instead, such as the AER.

In addition, and for this reason, the Design Development Team should ensure that any technical adviser employed can demonstrate that is not in a potentially conflicted position.

(d) Should the ESS framework provide for flexibility for the System Controller to procure other undefined categories of ESS? What, if any, regulatory prescription or oversight should apply?

Yes, if necessary. In terms of regulatory oversight, please refer to our response to item (c).

(e) What mechanisms are most appropriate for the Territory to preserve inertia and system strength? Should these be defined as ESS? Where would responsibility for their provision more appropriately reside – the Network Operator or the System Controller?

As they are currently both the same entity (PWC), the choice of System Controller or Network Operator appears to be one of semantics. There seems to be little value in drawing the distinction in that context.

It should be noted that in preparing our response to this question, EAL posed a number of questions to the System Controller regarding the technical methods used to control frequency on the DKIS. As at the date (nearly 3 weeks) of this submission, we have yet to receive a detailed response to these questions, so we are forced to make high level comments at present, until we receive more detailed information and can provide more specific recommendations.

In general terms, however, in any power system the required level of inertia depends on the speed of response of the available power generation fleet. To draw an analogy using a truck and a motorcycle: a truck has higher inertia, nevertheless a motorcycle can be much better at maintaining a constant speed in the face of sudden hills because it is so much faster to respond. To assist in the energy transition, grids need to become more like responsive motorcycles and less like (high inertia) trucks.



To take an example, grid forming inverters are able to operate AC power systems without any form of additional inertia due to their exceptionally fast control systems and response times. This capability is sometimes referred to as “synthetic inertia”. At the scale of the DKIS, power generation equipment (whether steam turbine / “frame” gas turbine / “aero-derivative” gas turbine or reciprocating engine) has power frequency control equipment that is sufficiently fast to manage the inertia that it brings to the power system itself. To take another example, there are many power systems across the world able to operate solely with aero-derivate gas turbines and inverters. This needs to become the default position for the DKIS during daylight hours, if we are to attempt to meet the NT government’s renewable energy target. If something is preventing that from occurring at present, then the priority should be to resolve that issue prior to moving any further with a reform process.

The equipment most sensitive to “Rate of Change of Frequency” (RoCoF) (eg steam turbines) is also the equipment that brings the most inertia to a power system. Generally speaking, consumer loads and inverters are relatively unaffected by RoCoF, provided a power system is sufficiently responsive to stabilise the frequency. So if slow RoCoF is required specifically by a market participant such as a steam turbine, then such market participant should be responsible for identifying and funding the necessary inertia (or synthetic inertia via batteries) itself. The role of the System Controller should only be to ensure due diligence that this is actually implemented and to not allow the relevant generator to connect if this inertia is not provided.

It has not been demonstrated that the DKIS has any specific issue with having insufficient inertia to operate in a stable manner. If market participants have this view, they should provide technical studies in the public domain, in their source form, for others to comment on and suggest simple changes that could fix the issue. These studies should demonstrate that all reasonable (and inexpensive) means to improve power frequency response have already been considered including, for example, using aero-derivative gas turbines in isochronous frequency control and the implementation and use of load-sharing lines across generators where possible.

The current requirement for a minimum of two Frame 6 gas turbines to be in operation at all times appears to have no technical justification. If power frequency is unstable without these generators being in service, then that is a reflection of inadequate frequency control arrangements and this should be fixed as a matter of priority. There is nothing to prevent aero-derivative gas turbines from maintaining stable frequency control on their own, as occurs in power systems across the world.

It has previously been argued that new entrant solar generation should not change the merit order of incumbent generators, as this would not be fair to the incumbents. However, EAL notes that effective competition is a benefit to consumers and no generator should be immune to competition. Every effort should be made to ensure the power system is operated in such a way that it promotes competition instead.

In terms of system strength, a particular definition (eg X/R ratio) is required to provide adequate comment. There has been significant discussion about “system strength” across Australia as NSPs come to terms with the issues involved, most recently in the Victorian “rhombus of regret”. However, it should be pointed out that many of those concerns appear



to have been solved with appropriate inverter control system tuning at much lower cost than originally predicted by some stakeholders and commentators. We need to ensure there is first a problem before we attempt to identify the best solution. The only way to do that is through the provision of detailed technical studies which first demonstrate a problem, which is typically very localised and specific if it exists.

Overall, ensuring adequate inertia and system strength should be a responsibility of the System Controller, under regulation from a suitably resourced regulator, due to the issues we have discussed under item (c).

Question 3

(a) What issues or concerns do current arrangements for the determination of system service requirements raise? How do these influence investment decisions made by power system participants and is reform warranted?

The provision of capacity forecasting in the NTC is a globally unique and very significant factor in making the cost of ESS very opaque in the NT, as far more than the required cost of the energy transition will be borne by new renewable energy generators complying with the requirements of Clause 3.3.5.17. The retro-active imposition of these very significant curtailments / costs on investors such as EAL is a stark warning for future investors to not invest in the NT power system. Reform is therefore very much warranted.

In general, C-FCAS costs should be focussed on price deterrents to introducing any increase in credible contingency for the power system in the form of large generators. However, in the NT, C-FCAS costs are currently funded by all generators and the reasons for that have never been adequately explained. Particularly when the high level of unreliability of incumbent generators (1 trip every 3.5 days, on average) means they call on this service far more often than is typically considered to be Good Electricity Industry Practice (GEIP).

In addition, the operation of Clause 3.3.5.17 of the NTC requires all new renewable energy generators to provide the equivalent of their own C-FCAS through the provision of fully accurate half hour forecasts, regardless of meteorological issues or the technical capabilities of prevailing forecasting systems. So renewable energy generators are effectively paying twice for this service, both through the cost of meeting these provisions and the C-FCAS charge of \$5.40/MWh.

The general principle is that loads should pay for the cost of ESS, as charging other participants (eg generators) will only cause those costs to be passed on to retail customers, usually with an extra margin. Charging generators for ESS should only be justified when they themselves cause a significant increase in the cost of ESS, for example if a new generator increases the amount of spinning reserve required to be held by the power system for a credible contingency. However, this should only be charged in proportion to the time period for which that generator is actually operating at such a level of output and not when its operation does not introduce a significant amount of incremental ESS.

As the DKIS already averages a very high level of spinning reserve (40 MW), the cost of providing it should probably be borne by the entity who decides to schedule such a high amount. In the face of such high levels of spinning reserve, it is difficult to understand how



capacity forecasting accuracy requirements for renewable energy generators add any value at all, particularly considering the extraordinary cost of compliance with NTC Clause 3.3.5.17.

(b) Should the ESS framework incorporate service standards, in addition to system standards? Should ESS standards be applied in a regulatory instrument, or in a System Controller instrument?

Both system and service standards are required as service standards can only be formulated from properly developed system standards. However, the first priority should be to include a reliability standard (used in the WEM) or value of lost load (used in the NEM), as it is impossible to identify economically efficient system and service standards in the absence of these benchmarks.

For reasons which we have already made clear, EAL's experiences in the NT electricity market have involved extreme commissioning and compliance testing delays from the System Controller and a lack of regulatory oversight. As a result of these experiences, we can only advocate as much independence for, as well as regulatory oversight of, the System Controller as possible. In our view, this should go to the extent of introducing an independent market operator and an appropriately resourced regulator to this market, so as to have greater independence and capability to effectively operate and regulate this market.

Ideally, it should be the case that local resources are able to resolve local issues faster and more effectively than national entities, however our experience is that this has not occurred in practice.

(c) Should the System Controller's determination of service requirements be subject to transparency and oversight mechanisms? If so, what arrangements are appropriate?

For reasons already mentioned in this document, EAL believes maximum transparency and oversight is required of the System Controller. All these standards should be subject to approval and oversight from a suitable and effective regulator.

Question 4

(a) What types of ESS are most suitable for market provision and in which systems? Are there certain categories of ESS which would benefit from continued Territory Generation delivery and why?

In EAL's view, C-FCAS is the main cost driver for ESS in the DKIS, in particular contingency raise ESS. Regulation and system restart ESS should be paid for by loads, as they represent the fundamental drivers for these requirements. Contingency lower ESS is, or should be, provided by all generators in accordance with the requirements of the NTC. This is much the same as the voltage control and reactive power provisions of the NTC, while likewise appear to be sufficient for the needs for these services without the existence of a market. It does not make sense to develop a market for a service which all generators are already mandated to provide.

The scale of the DKIS does not appear to justify full spot market provision of any ESS on an interval basis, as occurs in the NEM and WEM. A default provider of ESS can instead be



selected but this should not be Territory Generation unless the market is properly tested first. Indeed the current cost that Territory Generation is charging for these services appears to be well in excess of the true cost. In terms of technology, it is clear to EAL that batteries are the lowest cost providers of ESS for the DKIS, at a much lower rate than the \$5.40/MWh currently being charged.

Therefore, EAL has no confidence that Territory Generation is the least cost provider of battery-sourced ESS. EAL is very concerned that it appears to be currently planned for Territory Generation to build a battery off the back of this very significant revenue stream, which the NT Government has stated has only a five year payback from this charge. It is clear that private providers of such services would accept much longer payback periods for this type of revenue certainty. They should be given the opportunity to bid into a competitive procurement process for these services.

It is also unknown how long the current monopoly arrangement for ESS is planned to last. For a new ESS procurement process, it would appear that a 10 year lifetime for such a contract would normally be an appropriate compromise between competitive tension on the one hand and capital recovery for the proponent on the other. It also aligns with the majority of the expected lifetime of the relevant batteries, depending on their duty cycle.

From EAL's position, the current \$5.40/MWh charge is both allocated to the wrong participants and is very onerous. It cannot be justified on this basis. If an alternative battery provider is able to accept a lower charge for ESS over a 10 year term, given the security of the revenue stream, then they should be the default provider. At this point in time, Territory Generation appears to be a very high cost provider of ESS, so the market must be tested for a lower cost option.

The services currently promoted to be provided by the new battery announced by the NT government should be open to a competitive procurement process so the cost can be checked. If the Design Development Team is assuming that Territory Generation's battery will be built and will therefore be the default provider of ESS, then it appears that these decisions have already been made, to the clear detriment of EAL and other private participants in the market. In which case, the decision has already been made and it is highly unclear what this consultation process is intended to achieve.

(b) What are the likely costs and benefits of spot market procurement of certain types of ESS in any of the Territory's electricity systems?

As already discussed, spot procurement of ESS does not appear sensible for a market the size of the DKIS, given that a battery is very likely to be the lowest cost provider and nearly all ESS can be procured from one or more batteries located across the DKIS by a single proponent or multiple proponents. However, any procurement process for long term ESS should be subject to competitive tension, rather than just being a monopoly that is granted to Territory Generation with no justification. If it is not, then this would become an example of the already mentioned conflicts of interest driving expensive outcomes for market participants such as EAL, as well as consumers.



It should also be noted that the FCAS / C-FCAS requirements of the NTC provide further ESS backup supply in the event that the capability of the nominated ESS provider is exceeded for any reason, particularly when generators are only partially loaded at the time.

(c) What service provision framework would deliver the most appropriate balance between costs and benefits for each category of ESS in each regulated electricity system?

As already discussed, competitive procurement arrangements for long term procurement of ESS *must* be undertaken for the DKIS to reduce the onerous \$5.40/MWh charge, as well as allocate it in analogy with other jurisdictions. The fact that Territory Generation is already procuring a battery for this purpose should not influence this outcome. If they are not able to bid a competitive price for this type of long term revenue stream in comparison to private industry, then that battery can be used for another purpose, such as day / night arbitrage of wholesale electricity prices. The fact that Territory Generation has already bought a battery should not influence this process at all.

Question 5

(a) What changes should be made to the current administered pricing arrangements for the provision of ESS provided by Territory Generation?

The current administered pricing arrangement (\$5.40/MWh) is the result of a monopoly that is expensive, inappropriate and a significant deterrent to private investment in the DKIS. It does not leverage any competitive tension to reduce electricity prices for consumers, as this cost is ultimately borne by them. We have suggested appropriate changes in our response to Question 4.

(1) What methodology should be used to determine prices for each of the ESS categories?

As already discussed, for a power system the size of the DKIS, there does not appear to be sufficient merit to introduce half hour interval trading arrangements for ESS. The procurement of ESS, particularly C-FCAS raise, should therefore be undertaken on a long term basis (eg 10 years at a time), to allow both investor certainty for cost recovery and competitive tension to manage the price. This would allow batteries to compete, as the likely lowest cost providers for this service. Similar arrangements should also apply to the other ESS services, all procured coincidentally so that synergies in the cost of providing multiple services at once (eg black start from a grid forming inverter, together with regulating FCAS and C-FCAS raise) can be realised.

(2) What processes should be put in place to ensure the administered prices remain up to date?

EAL does not believe any administered prices would be appropriate for the DKIS. In our view, prices should be set by competitive procurement. The drivers for an effective market include:

- A competitive process for initial procurement of services;
- Long term price certainty for investors, to the extent this is both possible and reasonable, to ensure repayment of capital invested, together with an appropriate return on investment;



- An appropriate review period to allow these prices to again be subject to competitive tension in the market.

As previously discussed, it is clear to EAL that batteries are the lowest cost medium to long term method of providing ESS in the DKIS, given the very low cost of capital that would be available for a secure, long term (eg 10 year) revenue stream for providing these services. A 10 year period is also a reasonable time to repay the capital invested in a battery, while allowing regular testing of the market. Shorter time periods would drive up the cost of ESS due to the accelerated recovery of capital charges.

It is for these reasons that EAL advocates for competitive wholesale procurement of all ESS for a 10 year timeframe. Bidders should be able to offer a combined bid for all ESS services as well as separable portions for each ESS service. While the new battery to be installed by Territory Generation should be able to compete for this contract, it should not be the default provider as this risks the current \$5.40/MWh charge being perpetuated, at a continued very high cost to NT energy consumers, as all these costs are ultimately passed on to them.

(b) What market power mitigation measures would be appropriate for the provision of different ESS by Territory Generation under a market provision framework?

As already discussed, there is no reason for Territory Generation to be the default provider of ESS, as batteries are clearly the cheapest form of providing ESS and every market participant is fully capable of installing and operating them. If Territory Generation is able to bid the lowest cost for ESS from its batteries for a 10 year ESS contract, then there is no reason they should not be able to win such a contract. Under this approach, Territory Generation would therefore not possess significant ESS market power, so there is no need for it to be mitigated.

This is a clearly preferable situation to any arrangement which would give the battery being procured by Territory Generation any preferential market access. Or the current arrangement, which only perpetuates a very expensive method of providing ESS, in the form of spinning reserve from inefficient gas and/or steam turbines.

Question 6

(a) What are the appropriate bases for the allocation of ESS costs?

The small scale of the DKIS means that the examples of other markets, such as the NEM, are not particularly relevant. Effort should be placed into finding ESS funding models that are simplified, fit for purpose and yet still encourage the right behaviours from market participants. In this context, it would be useful to have a breakdown of the approximate cost of ESS according to each category for all stakeholders to be able to compare them.

It should first be acknowledged that electricity consumers ultimately fund all costs of operating a power system. If a cost is attributed to any other participant, they will only be then passed on to consumers, often with an added margin.

In EAL's view, as already mentioned, the vast majority of the cost of ESS is in the form of contingency raise FCAS. Given the very high levels of spinning reserve being provided in the DKIS, the only justification for passing any of this cost on to generators is if a generator



introduces a new credible contingency to the power system that requires higher levels of ESS. There should be a price disincentive to introducing a credible contingency that is greater than currently experienced. Otherwise, there is no justification for charging generators for the cost of ESS. The cost of “business as usual” ESS should be funded directly by customers, to prevent added margins.

(b) Are there alternatives to a causer pays approach for the recovery of the ESS costs?

The definition of “causer” is problematic here, as there is significant debate as to which stakeholder is a “causer”. In the end though, it is clear that consumers pay all costs of operating a power system, as all these costs are ultimately passed on to them. Again, charging these costs to others inevitably involves adding some form of margin to the charges before they are ultimately charged to the consumer. So a justification is required to charge them to any market participants other than retailers, who represent customers in the wholesale market.

The only example where this would appear justified is in the case of the C-FCAS raise service, if a generator introduces a credible contingency that is greater than that currently being used.

(c) Are there any technical barriers to the adoption of a causer pays or alternative approaches to ESS cost recovery in the Territory?

Technically, there is significant overlap between many of the services mentioned in the consultation paper and the requirements of the NTC. For example, all new generators must provide very significant levels of reactive power and have the capability to provide voltage control. They are not remunerated for providing these services, which are just a pre-condition to connection. It is therefore very difficult to see how services which are mandated can then be remunerated and / or incentivised. The same issue applies to C-FCAS lower services in the current NTC.

If the question relates to incentivising legacy plant that do not have to comply with these provisions in the NTC, then it would appear particularly unfair for legacy plant to gain a revenue stream from providing a service that a newly built plant is mandated to provide. EAL cannot imagine a justification for such an outcome. If legacy plant is currently providing these services, they should be required to continue providing these services as if they were new plant where these provisions are mandated.

(d) What issues would the transition to a causer pays or alternative basis of ESS cost allocation present for system participants?

EAL is currently experiencing overwhelming challenges in funding the \$5.40/MWh charge on top of the forecasting accuracy requirements of Clause 3.3.5.17. A transition to a more appropriate ESS regime would be very much welcomed.

(e) What oversight or regulatory arrangements should accompany any causer pays cost allocation or alternative arrangements?



EAL has already commented on oversight arrangements under Question 2. The same comments apply here.

Question 7

(a) What are the issues which need to be considered in determining which legislative and regulatory framework would best accommodate changes to the Territory's ESS framework?

EAL has no comment on the best legislative method for making changes to the ESS framework, or the relevant codes, as this is primarily a legal matter.

However, we re-iterate that Clause 3.3.5.17 of the NTC is an incredibly costly method of providing ESS and needs to be quickly repealed in order to restore private sector confidence in the economic regulation of the DKIS, which has been seriously damaged by the provisions of this clause and its associated procedure. Alternative solutions to the problems presented, that are far less costly and more effective, have not even been investigated, let alone properly considered. Consistent consultation feedback to this end has been ignored, with no technical or economic justification provided. This needs to be resolved as a matter of urgency, before any proper consideration can be given to the optimal ESS framework for the NT.

(b) What improvements can be made to the governance of the ESS framework?

As previously mentioned, the conflicts of interest inherent in PWC's various roles are both clear and untenable and EAL notes the consultation paper acknowledges that this may not reflect best practice. It is clear that ESS governance arrangements need to be changed in order for appropriate decisions to be made.

There appears to be a role for an independent Market Operator, who is not subject to the conflicts of interest that appear to have led to such inefficient and ineffective outcomes such as the new Clause 3.3.5.17 of the NTC. There is also scope for a regulator with sufficient resources to form a properly independent view of the issues at hand.

If you have any questions about this correspondence, please don't hesitate to contact Antony Piccinini on +61 400 345 455.

Yours sincerely,

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APPENDIX

ENI AUSTRALIA LIMITED SUBMISSION ON DRAFT GENERATOR FORECASTING
COMPLIANCE PROCEDURE



Ref.: CBD.LT.6110.PWC.SR

15th May 2020

via email: market.operator@powerwater.com.au

Generator Forecasting Compliance Procedure Consultation Submission

Eni Australia Ltd (EAL) makes this submission to Power and Water Corporation (PWC) in response to the consultation process for the draft Generator Forecasting Compliance Procedure (GFCP) document published on 16th April 2020. This forms part of PWC's requirements under clause 3.3.5.17(f) of the new Network Technical Code (NTC).

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. These projects are currently under construction.

1. Background

- EAL notes that many of the points made in these submissions were previously made in its submissions to the NT Utilities Commission (UC) in response to the draft GPS dated 29 January 2020. EAL would also like to confirm its position that it firmly remains of the view that the forecasting provisions of the new NTC are onerous and will cause significant detriment to new renewable generators such as EAL and will, in practice, work contrary to the publically stated NT renewable energy targets.
- Despite EAL's prior submissions on the same topic, the issues EAL has raised have not been addressed in the final GPS nor in the draft GFCP and no response has been provided by either PWC or the UC, despite the very high cost these provisions impose on new generators such as EAL.
- EAL remains disappointed by the lack of grandfathering for existing investment decisions and the lack of adequate justification as to how grandfathering would have impacted power system reliability.
- EAL's likely cost of compliance with NTC Clause 3.3.5.17 is in excess of AUD25 million, due to the potential 100% curtailment inherent in these provisions, in contrast to the maximum 80% curtailment previously advised in the Final Decision of the Utilities Commission (end page 76).



- In the entire consultation process with respect to the GPS and again with the draft GFCP, PWC has lacked transparency on technical studies, models and algorithms to support its claims of impaired system security or reliability from variable solar farm output. It has also lacked transparency with respect to any potential conflicts of interest regarding benefits it receives from gas sales by curtailing renewable electricity generation.
- The draft GFCP has failed to take into account the recent announcement by the NT government of the installation of a centralised battery in Darwin, which would be able to manage aggregated solar variability from existing projects on its own, if utilised correctly.

2. Response to draft GFCP

EAL has a number of significant concerns with the operation of NTC Clause 3.3.5.17 and the draft GFCP, as set out below.

(a) Indirect Technology Discrimination

The draft GFCP describes two potential types of non-compliance, with vastly different implications for generators, as follows:

- *Type 1 non-compliance – Asset Failure*: this is the failure mode that will most often apply to conventional generators and results in an accelerated return to service with no ongoing curtailment obligations, regardless of how often it occurs or how big the impact on the power system at the time.
- *Type 2 non-compliance – Forecasting Algorithm Failure*: while not specifically stated, practically this type of failure can only apply to solar farms and results in a lengthy return to service process with very significant discretion from PWC as to the acceptability of different forecasting algorithm changes, which gives no clarity for making investment decisions.

The provisions appear to have been specifically designed to be particularly onerous for solar farms to achieve (at PWC's complete discretion), while having no impact on conventional generators. No justification has been provided for this distinction, either within or outside of the draft GFCP. The potential impact on the power system appears to be much more moderate for a Type 2 non-compliance than the complete trip that typically occurs in a Type 1 non-compliance.

Quantum of forecast error

Under this proposal, a 25 MW conventional generator can potentially trip every day, or multiple times per day, from full load, without ongoing curtailment. However EAL's 25 MW Katherine solar farm must not vary from its forecast by more than 1 MW or it will suffer ongoing curtailment and a very lengthy return to service process to relieve constraints if PWC accept any changes to forecasting algorithms, which it is under no obligation to do. In EAL's experience with similar issues, this is likely to take months, at a minimum, as it is not time constrained on PWC's behalf and it is not clear what generators need to do in order for a forecasting algorithm to be approved.

This procedure has the effect of allowing conventional generators to call on C-FCAS to accommodate the impact of their trips but not solar generators. Technical studies have never been provided to justify why solar generators are not able to do this for their forecast errors. A properly conducted unserved energy analysis would quantify this impact and also quantify the level of aggregated battery capacity required for greater solar production to have no



impact on power system security and reliability in the DKIS. However, this has still not been provided by PWC as at the date of this submission. It is highly unusual for changes of this nature to have been approved in a regulated electricity market in the absence of such studies.

Frequency of forecast error

In previous consultations, as referenced at the bottom of page 79 of the UC Final Decision, PWC argued these provisions are required because existing generators on the power system are very unreliable (tripping approximately 100 times per year). However, these provisions do nothing to ameliorate this unreliability and prevent it occurring in future, as they just maintain the current treatment of forced outages from conventional generators. So there is no requirement or incentive for either existing or new conventional generators to improve either their own reliability or overall power system security. In light of the curtailment or battery costs that will be experienced by solar generators such as EAL, this is unacceptable.

Under the draft GFCP, conventional generators are able to frequently completely trip and still be compliant with NTC Clause 3.3.5.17, and therefore return to service promptly with no ongoing curtailment. This is an unjustified interpretation of the clause and effectively exempts conventional generators from complying with it. It has the practical effect of removing the need for conventional generators to provide forecasts at all, as they can choose to completely miss them at their own discretion. It is also an incentive for solar generators to just trip in the event of an unexpected cloud event, in order to take advantage of the Type 1 non-compliance provisions. It is difficult to see how this would yield a more secure power system.

In addition, PWC previously argued that the frequency of solar farm variability justified the need for these provisions, using study results referenced on page 79 of the UC Final Decision. While the referenced studies are still unpublished and unavailable for external review (with no justification ever provided for this decision), they contain clearly unrealistic assumptions, such as the assumption of no governor response from conventional generators. If the conventional generators on a power system do not respond to loading variations, it is especially difficult to see how it can be controlled, particularly in light of the NTC requirements for all generators to respond to frequency variations.

In any case, the draft GFCP does not take into account the frequency of non-compliance for either Type 1 or Type 2 events. As Type 1 non-compliance events have such a large impact and are occurring 100 times per year, it stands to reason that they should receive much more onerous consideration than Type 2 events. Instead, every time a Type 2 forecasting error occurs, constraints are enacted regardless of the frequency with which it occurs, or whether it actually offsets concurrent forecast errors from other solar farms, i.e. effectively with no impact on the DKIS. This is arbitrary and unjustified as it is very clear that, for example, a 1 MW forecast error (K_M) would have no impact on power system security at all, in comparison to continuous 25 MW trips from conventional generators, for which there is no effective sanction. If it did have a significant impact, then the trip of a 1 MW conventional generator should be treated in the same way as a 1MW forecast error from a solar farm, but it is not.

Only one type of power system impact

In EAL's view, the only way the proposed approach can be non-discriminatory on a technology basis is for there to be only one type of forecasting non-compliance. As the two proposed types of non-compliance have the same impact on the power system, they should be treated



equally. There is no justification for separating them in this manner, other than to have the practical effect of favouring conventional forms of gas powered generation, thus creating an effective barrier to entry for renewable generators. All generators should have to comply with either a non-compliance to forecasts in the same way, regardless of whether they are solar or conventional, or whether they trip or have an algorithm error.

(b) Inadequate Detail for Investment Decisions

In any regulatory environment, regulations should allow stakeholders to reasonably forecast a level of economic return before taking an investment decision. Without prejudice to EAL's view that any additional investment required as a result of changes in regulations after a final investment decision is unacceptable, the current structure of the GFCP does not provide any confidence of the level of further investment required to achieve compliance.

The UC Final Decision (bottom of page 76) indicated the maximum BESS capacity required to achieve full compliance in relation to the forecasting provisions was 80% of rated capacity, for 30 minutes. The draft GFCP does not align with that philosophy, as it allows for curtailment of up to 100% of output, which would not be sufficiently covered by a BESS of 80% of output. A reasonable minimum production / curtailment threshold must therefore be applied, as per the stated intent of the UC Final Decision, which would imply a maximum curtailment of 80% of solar farm capacity.

Potential Battery Size and Cost

In the case of EAL's solar farms, achieving 80% of output cover for 30 minutes as advised in the UC Final Decision, represents a potential cost of over AUD 20 million, plus additional operating and maintenance costs, including the round-trip inefficiency of the required batteries. The draft GFCP does not align with that philosophy, as there is nothing within it to prevent a generator who has made such a significant additional investment from still being curtailed due to non-compliances with the various factors in the forecasting algorithm. Considerable extra costs may be incurred in practice once these algorithms are applied in real operations. PWC's previous assurances have not been supported by appropriate guarantees in this regard. All the risk of whether the available technologies are actually able to meet these provisions rests with EAL.

Under the draft GFCP, it is indeed likely that, having made such a significant additional investment, considerable curtailment of solar output will still be incurred, at the very least because of the need to make very conservative forecasts so as to not incur curtailment by exceeding the various thresholds. This represents significant additional lost production from our solar farms, likely to exceed 10% of available solar energy, even after spending such a large amount to prevent curtailment.

PWC Discretion

In the draft GFCP, there is very considerable discretion given to PWC in the Type 2 non-compliance process to review and reject proposed forecasting changes made by generators. This is a considerable and unprecedented over-reach on the part of PWC. The original justification for these forecasting provisions was that it was a performance standard with built-in curtailment, so how a generator meets that standard should not be of concern to PWC. This is contradicted by the discretion that the draft GFCP would give to PWC to approve forecasting. It makes it appear that PWC wishes to implement a performance standard while



still retaining complete control of how generators achieve that standard, in which case there is no justification for the implementation of performance standards in the first place.

PWC's rights to review and approve generator's proposed forecasting methodologies means that PWC is no longer implementing a performance standard but instead mandating and approving forecasting methods. If such is the case, then the GFCP should clearly indicate the forecasting methods, algorithms and associated technologies that will be accepted as adequate to prevent curtailment, rather than leave generators so exposed to both forecasting inaccuracy risk and PWC's future discretion to approve forecasting algorithms. At least this would give generators some certainty that if they implement a particular forecasting solution, they will be able to operate on an un-constrained basis, which is completely lacking at present.

The UC has previously argued (page 77 of the Final Decision) that generators can rely on PWC using its discretion to negotiate sensible outcomes using negotiated access standards. EAL's experience is that this discretion is a very considerable risk to investments and this has been amply demonstrated by the introduction of these unprecedented forecasting requirements and PWC's refusal to consider reasonable alternatives that have been shown to be much more cost effective.

In all cases, the considerable ability for PWC to impact EAL's investments should be constrained as much as possible. At the very least, if a forecasting regime is to be applied, the GFCP should specify up-front what PWC deems to be a compliant suite of algorithms and technologies for the *automatic access standard* for NTC Clause 3.3.5.17.

Unacceptable Uncertainty

In summary, and without prejudice to EAL's view that any additional investment required as a result of changes in regulations after a final investment decision is unacceptable, the level of detail in the draft GFCP is completely inadequate for any investment decision to achieve compliance. As PWC has taken a globally unique (as well as unjustified) approach to forecasting, there are no precedents from which EAL can have confidence in achieving reasonable outcomes. At present, EAL is being forced to choose between incurring an additional cost of over AUD 25 million for battery storage, likely with remaining output constraints, or curtailment of up to 100% of the output from our existing facilities. This is unacceptable and would be unpalatable for anyone who wishes to invest in the NT.

For all the other provisions of the NTC, EAL can assess its compliance in advance and accordingly make decisions on additional measures required. The discretion and inherent uncertainty in the draft GFCP makes it impossible for EAL to have confidence in any curtailment outcome for any level of investment, on top of its existing, considerable investments in the Northern Territory.

(c) Unable to determine compliance

In accordance with the provisions of Clause 12.3(b) of Version 4 of the NTC, generators are required to provide to PWC a statement on compliance with the provisions of the NTC. As currently proposed, it is impossible to determine compliance with the *automatic access standard* in Clause 3.3.5.17(b), regardless of the level of acquired battery support, without testing any system on a physical plant over many years.



Any constraint resulting from the draft GFCP would result in a breach of the *automatic access standard* and could arise at any time and for any reason, which is impossible for a generator to predict in advance. This is contrary to the other clauses in the NTC, for which it is possible to confirm or deny in advance our compliance with the *automatic access standards* with some degree of confidence.

The core problem is that these requirements are being imposed on generators in the absence of any evidence that an adequate forecasting system is available, at any cost. It has never been tried before, nevertheless very significant constraints would be applied under the draft GFCP for failure to perform. PWC's previous assurances during consultation workshops that lower levels of battery storage should be adequate to meet the requirements of Clause 3.3.5.17 of the NTC have not been backed up with guarantees to that effect in the draft GFCP. Therefore, they have no value to EAL or other renewable generators. The entire risk of whether the available technologies will be compliant with the draft GFCP sits with generators; PWC takes no risk at all, while imposing an *automatic access standard* that it has not demonstrated is capable of being complied with.

(d) Treatment of Combined Generators

The UC Final Decision (page 77) stated that "the NTC does not prevent alternative arrangements such as the use of a central battery", following PWC advice to that effect. Aligned with our previous submissions on this topic, it remains our view that this is incorrect. Generators are clearly not able to combine their forecasts or share battery services from alternative providers at other sites under either the NTC or draft GFCP. All generators (including batteries) must comply with the NTC, including the forecasting requirements of 3.3.5.17 and the GFCP. The methodology for achieving such an outcome is completely absent from the draft GFCP in any case. This should not be left to negotiated access standards to fix, as it would result in a complete lack of transparency, or a complete disregard of the NTC.

In any case, if the intent is still to allow alternative arrangements and the NTC / GFCP is modified to allow this, then EAL has a number of questions, including:

- can multiple solar farms owned by the same entity at different sites combine their forecasts, dispatch and other factors under the GFCP algorithms? If so, how will this be implemented in practice, given the site specific dispatch systems currently in place? How will the relevant factors be shared across the sites?
- can multiple solar farms owned by different entities at different sites combine their forecasts, regardless of whether these solar farms are "behind the meter" or not? If so, again how is this implemented in practice, in terms of dispatch, the GFCP factors and the constraints applied to each entity / site?
- can solar farms combine with conventional generators to provide their forecasts, whether those generators are grandfathered or not, either individually or in aggregate?
- will this require knowledge of the commercial arrangements between the various parties in order for PWC to implement? Please provide the rationale for this choice.
- does sharing of forecasting from different sites require a commercial agreement between the entities involved, with a single forecast being provided to PWC?
- can PWC implement the forecast sharing methodology itself so that if one generator's under-forecast coincides with another generator's over-forecast, then no penalty is imposed, regardless of whether a commercial agreement exists?



- if a commercial agreement must exist between the entities, then why is it required, given that the system impact is the same in both cases?
- can solar farms, either jointly or separately, share their forecast error with the rooftop solar forecasts that PWC makes? For example, if PWC under-predicts rooftop solar production at the same time as a single generator, or multiple generators, over-predict their production, will a curtailment penalty still apply and why?
- what constraints will apply to rooftop solar production and solar / load forecast error on the part of PWC and what penalties will apply to them? If none, why is there no incentive for PWC to improve rooftop solar / load forecasts as the technologies involved are the same that it is asking generators to implement? If this occurred, then would some of the GFCP factors be able to be relaxed on large scale generators?
- will the various factors in the draft GFCP be added together when multiple solar farms or conventional generators share a combined forecast? If so, will this be done on a site or entity or other basis and why?
- for example, if the estimated take-up of large scale solar farms ever meets PWC's previous assumption of 120 MW and they all combined their forecasts, then will PWC retain the requirement for the K_M factor (as well as the others) in the draft GFCP to still be below 1 MW? If so, why?
- if not, what size of combined solar farm forecast would justify lifting the K_M threshold above 1 MW and to what extent would it be lifted? The same question also applies to all the other factors in the draft GFCP.

It would appear particularly excessive for a 100 MW combined generator to be held to a forecast accuracy requirement of 1 MW, but that appears to be the case in the draft GFCP. EAL also notes that the UC's intent for requiring a GFCP was to provide greater certainty to generators but it currently appears to generate more questions than answers.

(e) Treatment of Conventional Generators

In the NTC, the forecasting provisions of Clause 3.3.5.17 apply to all new conventional generators. So once all existing, grandfathered generators have been retired, all generators will have to comply with their own forecasts, leaving them unable to provide C-FCAS or FCAS services, or even follow system load variations within a half hour period, in the absence of a significant frequency variation. It therefore appears that load-following services cannot be provided by new generators, as they must instead meet their own forecast to prevent a Type 2 non-compliance.

Any negotiated access standard to exempt new generators (including batteries, which are also generators under the NTC definitions) from the requirements of Clause 3.3.5.17, in order to allow them to firm up solar generation, follow their respective loads or provide FCAS/C-FCAS, would require the complete removal / derogation of the forecasting requirement / Clause 3.3.5.17. PWC does not appear to have (or should not have) the discretion to completely remove this requirement using derogations or negotiated access standards. If this approach was taken, it would also raise the question of why the same consideration could not be applied for other generators, including solar generators, if technology agnostic Generator Performance Standards are being applied. In this respect, the NTC would appear to become unworkable to implement as grandfathered generators retire from service.



It also appears to have the effect of preventing new conventional generators from providing firming services for solar generators. This is not consistent with the UC's Final Decision (page 77) on alternative arrangements.

In essence, the problem is that if all generators must comply with the new NTC and meet their own half hour production forecasts, then who is following the load? If a single generator or group of generators is nominated for regulating FCAS or C-FCAS, how can they be made exempt from the requirements of Clause 3.3.5.17, while others are not exempt?

(f) Treatment of Batteries

The press release for the new centralised battery issued by the NT Government states that it may potentially be available for forecasting purposes. However, in the same manner as applies for other generators, no information is provided in the draft GFCEP as to how this could be implemented under the NTC among different entities owning different solar farms and/or batteries. EAL is unable to compare its potential compliance options without this information. EAL's additional questions on this matter include:

- How is it possible, in the case of a battery, for the same connection point to be both an entry point and an exit point under the NTC, having to apply the technical requirements for both *Generator Users* and *Network Users* concurrently? This appears to be a similar regulatory issue to that currently preventing the connection of batteries in Western Australia.
- More broadly, why don't specific provisions for batteries exist in the NTC?
- As a stand-alone battery is both a *Generator User* and a *Network User* under the NTC, then what prevents it from also having to comply with its own forecasting requirements under Clause 3.3.5.17, as applies to every other *Generator User*?
- If it must comply with its own half hour forecasts, how can it then be available to firm up forecast inaccuracy from other generators, as this would mean non-compliance with its own forecasts? If PWC believe a stand-alone battery is not a *Generator User* or otherwise does not need to comply with the requirements of NTC Clause 3.3.5.17, then please specify the relevant clauses of the NTC that allow for this exemption.
- As we see no ability in the NTC for batteries to be exempt from the provisions of Clause 3.3.5.17 (as they are a generator), then how is it possible for any new stand-alone battery to provide FCAS or C-FCAS services (in the absence of a frequency excursion) as outlined in the recent press release on the battery that T-Gen is procuring? Please note that this is different to the frequency response provisions of clause 3.3.5.17(b), as no frequency deviation would eventuate in normal operation.
- If PWC intend to interpret any C-FCAS or FCAS from a battery as being in response to a frequency event in order to void the requirements of Clause 3.3.5.17(b) (absent a material deviation of system frequency), then why can't solar farms be given the same consideration?
- As a result, doesn't this mean that all battery capacity must be placed behind the connection point of each solar farm for which it provides firming services, up to the nameplate rating of that solar farm?
- This would contradict the UC Final Decision (page 77), as well as the spirit of prior GPS consultation documentation and multiple statements from PWC and the UC on this matter, which specified that there was nothing to prevent the implementation of shared batteries, at potentially different locations. How can this be the case?



- EAL has continually provided this feedback in all the consultations to date but has never received a response, other than the above mentioned statements, which still appear to be inaccurate under the NTC. We still cannot see how a central battery for solar firming can connect without having to provide its own output forecast, as it is a *Generator User*, unless it is behind the connection point of another *Generator User*, who must comply.
- This means that shared or stand-alone batteries cannot be used and each solar farm has to supply its own batteries at its own site for forecast support at very high cost and likely 100% coverage under the draft GFCP if it wants some confidence of avoiding constraints. Is this the intention? If not, how can this be otherwise achieved in compliance with the NTC?
- Would this also prohibit the benefits of centralised batteries to provide network support or other services, as per EAL's previous submissions?
- Part of the UC's reasons for approving the current NTC appear to be because it was led to believe that shared / stand-alone batteries were possible and could also provide valuable network support services. If this is not the case, will the UC be informed?
- If it was possible in some way (that we cannot see) under the NTC for different entities across different sites to share forecasts and battery support services from a third party, then how will any constraints from the resulting forecast errors be shared among the various entities?
- In the above scenario, will any constraints apply to the battery service provider, or just to the solar farms and why?
- If the same battery is also being used for FCAS / C-FCAS services (by T-Gen), then how will its capacity (both in MW and MWh) be credited among multiple additional forecasting and FCAS / C-FCAS users? While the draft GFCP describes an algorithm for individual constraints, it doesn't describe any overlap with FCAS / C-FCAS services or between entities sharing a battery for forecast firming services. To comply with the expectations laid down in the UC's Final Decision, it must do so.
- If additional network support services are provided by a battery (e.g. black start, firming services for rooftop solar / loads, static or dynamic voltage support to address existing network issues or providing synthetic inertia), then how will these services be compensated, outside of the existing monopoly arrangement for FCAS / C-FCAS enjoyed by T-Gen?

Broadly speaking, it appears that stand-alone or even shared batteries will be unable to comply with the NTC without substantial changes to both NTC Clause 3.3.5.17 and the draft GFCP. In EAL's view, this type of change cannot be accommodated using *negotiated access standards* without compromising the integrity of that process, as it requires complete removal of the requirement. EAL therefore requests another consultation process to change the NTC to accommodate batteries and/or remove Clause 3.3.5.17. Unless the intention was always for batteries to be located behind the connection point of each solar farm, which is not consistent with the UC's Final Decision, or PWC's prior documentation and assurances.

(g) Amount of batteries – and cost

As above, it appears that stand-alone or shared batteries cannot be accommodated under the NTC for solar forecasting purposes and there is no limit to the constraints that will be applied to solar farms under the draft GFCP. Therefore, to have some hope of compliance, each solar farm must be able to supply up to 100% of its output for half an hour, if we unrealistically assume an otherwise perfectly functioning forecasting and battery control algorithm can be



discovered, for which evidence has not been provided. This increases the cost of batteries above previous estimates, which assumed 80% coverage for the same time period. For EAL's solar farms (45 MW total), this increases the likely cost from \$20 million, as previously advised, to \$25 million. EAL re-iterates its position that the requirement for batteries installation for 80% of the capacity is by itself sufficient to make any project uneconomic (absent a renegotiation of electricity price); an increase to a 100% battery backup simply worsens an already intolerable condition.

In PWC's previous submissions in support of the new forecasting requirements (see page 33 of the June 2019 GPS Consultation Paper), 120 MW of large scale solar farm capacity was assumed to be installed in the near future. This was based purely on generator connection applications from project developers, rather than any realistic assessment of market demand for large scale solar farms in the DKIS. PWC was also unable to estimate likely forecasting accuracy from solar farms in this document, which should have been a pre-requisite before applying accuracy requirements it did not know could be achieved at any reasonable cost. The system reliability impacts suggested in this document are therefore unrealistic, even if they were modelled correctly, which we are unable to confirm as the model has never been provided for review, even to the UC's consultants, for reasons that have never been explained, despite repeated requests for this to occur in our previous submissions.

Nevertheless, keeping this 120 MW assumption, for solar farm owners to gain at least some degree of confidence in gaining unconstrained access means they must, in aggregate, install batteries of 120 MW and 60 MWh capacity across the DKIS under the draft GFCP. The likely cost of this is over \$65 million, using GHD's benchmarks for battery costs. In addition, the NT Government's recent large scale battery announcement for FCAS services (media release of 5 April 2020) represents a \$30 million investment, with unspecified capacity / energy characteristics but presumably in the order of 60 MW for over half an hour, based on equivalent cost assumptions. So it is clear that, in these arrangements, PWC and the UC are comfortable with a total likely battery cost across the DKIS in the order of \$100 million, for batteries totalling around 180 MW of capacity, for half an hour of continuous operation. These batteries will most often be fighting each other so as to merely ensure compliance with their own forecasts, rather than any power system outcome.

There is no possibility that EAL could have been able to anticipate such an unrealistic, inefficient and expensive requirement would receive approval from an independent regulator before taking investment decisions. There is no rationale that could possibly justify such an expensive outcome for so little return. It should again be noted that all these costs will ultimately be paid for by electricity consumers in the Northern Territory.

(h) Paying twice for batteries

EAL notes that the requirement for all generators to pay FCAS charges to T-Gen has not changed and these funds will now be used to pay for T-Gen's new battery, as recently announced by the Northern Territory Government. So, in addition to being asked to invest in a battery large enough to provide 100% output cover for half an hour for its own solar farms (and therefore not calling on C-FCAS services ourselves), EAL must also provide additional funds so that T-Gen can build a large enough battery to provide output cover for its generators, which PWC and the UC Final Decision (page 79) have previously noted have very low levels of reliability.



EAL also notes from the press release that this T-Gen battery has a simple payback period of under five years on the basis of the revenues that EAL (and others) must fund, making this a very profitable endeavour for T-Gen. Therefore, previous statements that existing FCAS charges were too low to cover T-Gen's costs do not appear to be justified. It is also very likely that an open process to procure FCAS services in the market would have reduced FCAS charges substantially, purely due to the longer payback periods that would have been accepted by private industry for such a secure revenue stream. Yet this option was not pursued and EAL is left with being forced to pay excessive FCAS charges as a result, in addition to very high costs of compliance with Clause 3.3.5.17 of the NTC.

This situation is unacceptable for private capital participants in the DKIS and is only exacerbated by the provisions of the draft GFCP, as already discussed.

(i) Disconnection or continuous constraint

The draft GFCP does not specify the level of non-compliance for disconnection, compared to the application of a constraint as per the worked example. It also doesn't specify the time period over which such a disconnection would be implemented. Presumably, this would occur over at least a half hour period in order to reduce system impacts, as against what appears to be an instantaneous disconnection that is presently envisaged, which would have a much more severe impact on the power system.

PWC should specify the circumstances under which it would choose the complete disconnection option. At present these are not clear, unless a 100% disconnection is applied by the relevant factors, which remains possible.

(j) GOTR Timeframes

The draft GFCP states that the "normal processing time for GOTRs is 10 business days". EAL's experience is that this process usually takes considerably longer and any new revision by PWC of associated documentation and procedures resets this timeframe, regardless of how minor. It also states that "a shorter time period may be arranged under special circumstances" without specifying what those circumstances might be. In EAL's experience, this has been impossible to secure for solar farms, despite repeated attempts in exceptional circumstances.

(k) Return to service time constraint

As per EAL's feedback on GOTR timeframes, all Type 2 non-compliance return to service approvals in the draft GFCP should have reasonable and specific time-bounds on PWC to expedite the return to service and constraint relaxation processes. The draft GFCP places no obligations on PWC with respect to this or any other requirement to act in a timely manner.

(l) Unserved Energy Analysis

As per its previous consultation submissions, EAL again requests quantification of the impact of the provisions of Clause 3.3.5.17 on system reliability and unserved energy. To date, no studies or models have been provided and EAL therefore retains its lack of confidence in the generic statements that have been used by PWC to date to justify these forecasting requirements, as well as our ability to negotiate reasonable access standards.



Of particular interest in the draft GFCP is the impact of increasing the various factors (e.g. K_M , K_P and D) on unserved energy. The thresholds for these factors are extremely low at present and no justification has ever been provided for them. An unserved energy analysis is the only way of discovering whether the cost of compliance with such low thresholds exceeds the system benefit, compared to other costs that could be applied to power system participants for much greater benefit in terms of reducing unserved energy. It is very likely that a substantial increase in these factors would have no real impact on unserved energy but would substantially reduce the cost of compliance for EAL and other solar farm owners in the DKIS.

In terms of the actual factors involved, the following are examples:

- *The half hour time period for provision of forecasts:* the selection of this period appears to be based on the time period required for the slowest conventional generator on the DKIS to start. This is indefensible as, during periods of high solar production, other generators that can start much faster will always be available. Reducing this factor to ten minutes (for example), or less, should be well within the start time of many existing or new DKIS generators and would reduce the cost of compliance by solar users by two thirds, with no impact on power system reliability or unserved energy.
- *The 1 MW threshold for K_M :* again, no justification has ever been provided for such a low threshold, which is well within the variability of loads and rooftop solar production. A significant increase in this threshold would significantly reduce the cost of compliance without any significant impact on power system reliability or unserved energy.
- *The 5% requirement for K_P :* as per the other factors, no justification has been provided and EAL believe a significant relaxation of this constraint can be accommodated with no impact on power system reliability or unserved energy.
- *The aggregation of D over a 24 hour period and only over non-zero forecasts:* as per the above factors, these choices are particularly mystifying as it is impossible to see even an indirect link between these choices and any power system reliability outcome at all.

All the above factors require an unserved energy analysis to quantify properly. In any case, none of this commentary should take away from the fact that generators should be capable of confirming their compliance with Clause 3.3.5.17 of the NTC in advance. This is not the case under the draft GFCP as constraints can potentially be applied at any time, regardless of the level of investment in forecasting or batteries, as forecasting performance against the draft GFCP remains unknown to everyone.

(m) UC oversight

In accordance with the requirements of Clause 3.3.5.17(f) of the NTC, PWC is required to consult with the UC on the draft GFCP. It is difficult to see how the UC can adequately provide its feedback in the absence of this submission and the other submissions being made by other stakeholders. Given the many substantive issues raised in this submission, EAL request the GFCP and accompanying submissions be provided to the UC for approval. At the very least, the UC should have the ability to provide its feedback to PWC in full knowledge of the submissions being made by all stakeholders.

(n) Response to consultation questions

In light of the aforementioned points, EAL provides the following responses to the specific questions raised in PWC's consultation document:



Is the proposed procedure aligned with the obligations outlined in the Network Technical Code?

No, for the reasons already outlined. There is no justification in the NTC or anywhere else for two types of non-compliances with such disparate constraint outcomes.

Does the procedure provide sufficient detail on the constraint setting process?

No, for the reasons already outlined, particularly with respect to the different treatment of the two types of non-compliances. The discretion for PWC to apply its own interpretation to these clauses and approve forecasting algorithms and methods in the constraint lifting / return to service processes is particularly difficult to accept as PWC is both applying a performance standard and giving itself complete discretion over how generators are able to meet it. No constraints can be predicted by generators from any particular level of investment in forecasting or battery services.

Is the procedure suitable for use by the System Controller?

No, for the reasons already outlined. Procedures such as those outlined in NTC Clause 3.3.5.17 and the draft GFCP should not be and have not been used by any power system controller due to their extreme cost and minimal benefit.

Does the proposed approach to under-frequency event and forecast appropriately balance minimising the impact of the initial under-frequency event while limiting the risk that future forecast errors present an unmanageable situation?

No, in order for this to occur PWC must be able to demonstrate that an unmanageable situation is likely to occur under more reasonable forecasting provisions that do not impose a half hour obligation. As per the feedback provided elsewhere in this and our previous submissions, PWC has failed to do this.

3. Conclusion

In conclusion, EAL maintains its significant concerns with Clause 3.3.5.17 of the NTC, as well as the draft GFCP. In summary, these include:

- Indirect technology discrimination through a type of non-compliance that has no impact on conventional generators, despite more severe impacts on the power system from their outages and their likely greater frequency compared to aggregated solar forecasting errors of the same magnitude across the DKIS.
- Inadequate detail for generators to be able to make investment decisions and retain any degree of confidence that they will be able to comply and still not be constrained as these forecasting systems have not been developed or tested yet. If PWC is confident that lower cost forecasting technologies will be fully compliant and result in no constraints, it should provide guarantees to that effect in the GFCP.
- Lack of any information about the treatment of shared generators or batteries and no information about how stand-alone batteries can comply with NTC Clause 3.3.5.17 and still provide forecasting services to other generators, or how the power system will be controlled when grandfathered generators retire and all generators have to comply this clause and the associated GFCP.
- No consideration of the extremely high cost of batteries that will be required across DKIS solar farms, all fighting each other's output in order to meet their own forecasts,



regardless of prevailing power system requirements. This is in addition to those batteries already committed by the NT Government in its recent announcement.

- No consideration of the fact that generators not only have to provide complete output coverage using their own batteries to attempt compliance with NTC Clause 3.3.5.17 but we also have to fund T-Gen's batteries, with no apparent reduction on FCAS charges.
- No specified maximum level of constraint applicable to generators in the absence of batteries, or any quantification of the amount of batteries or other equipment required to guarantee that a constraint will not be applied in normal circumstances. There is no ability for generators to be able assess the level of constraint that is likely to be applied in exchange for their potential investments in batteries and forecasting algorithms and services, as the performance of each option against the GFCP is completely unknown in practice.
- No justification of the arbitrary factors being applied in the draft GFCP algorithm.
- No time limits on PWC for the return to service or GOTR processes.
- Non-disclosure of considerations regarding potential conflicts of interest in the development, approval and implementation of the NTC and the draft GFCP. Constraints on solar generation should not be applied by entities who derive a financial benefit from those constraints.
- Lack of any oversight by the UC for the GFCP, or Clause 3.3.5.17 in the light of this and other submissions.

As outlined herein, many of these issues are in contradiction to public assurances given by PWC during the GPS consultation process and by the UC in its Final Decision. Therefore, EAL requests a complete review of NTC clause 3.3.5.17, together with an unserved energy analysis to quantify the need for aggregated solar forecasting or battery support services in the DKIS. This is requested particularly in light of the NT Government's recent announcement of the provision of its own battery, which is likely to provide sufficient coverage for these issues for the foreseeable future in light of actual market demand for large scale solar farms.

Yours sincerely,

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