EMERGING GENERATION AND ENERGY STORAGE IN THE NEM

Response to stakeholder paper

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1 SECTION 2: DEFINING AND INTEGRATING GRID-SCALE ESS INTO THE NEM

1.1 SECTION 2.4: IMPROVEMENTS TO INTEGRATE ESS IN THE NEM

Question 1: Referring to Section 2.3, are there any other issues with the current arrangement for ESS?

Edify Energy in its development of the Gannawarra Energy Storage System (GESS) has identified a number of issues with the current arrangements for ESS, particularly where it applies to the retrofit case. These issues can be categorised into four areas as follows:

1. Location of connection point for dedicated asset substations

<table>
<tr><th>Issues</th><th>Potential solutions</th></tr>
<tr><td>

The current rules require that a connection point and associated relationships (e.g. NMI, FRMP, DUID, etc.) are located as close to the physical point of common coupling with the connecting NSP as possible.
In the case of new-build renewables, this requirement typically results in the placement of the connection point on the high-voltage (HV) side of dedicated substations.
Locating the connection point on the HV side limits the potential for future assets to connect into these substations in a retrofit arrangement.
At present, connecting a new asset (ESS or otherwise) into these substations requires complex changes to the existing asset, including the movement of the point of GPS enforcement, movement of meters and market roles (e.g. Market Generator), and redetermination of MLFs and / or DLFs.
Among other things, this requires a renegotiation of the existing GPS, which includes giving regard to:

the new FIA process;
changes to the system that have occurred since negotiation of the initial GPS; and
a new commissioning and testing procedure and hold point process to prove compliance with the new GPS.

Particularly in the case of renegotiating the GPS, these changes create a material risk to the existing asset and therefore an impediment to investment for the new connecting asset.
This would be a sub-optimal market outcome as it limits the potential for new connecting assets to access existing underutilised network infrastructure and to be deployed at lower overall system cost.
The materiality of this opportunity would be significant, with likely dozens of examples of dedicated substations, which in the case of solar are only used for ~8hrs of the solar day.

</td><td>
Greenfields development

In the case of new asset development, where it may be contemplated in advance that an additional asset could connect in the future, create a transparent set of arrangements that allow for a connection point to be situated on the Medium Voltage (MV) side of substations such that the GPS and all associations to the connection point are correctly based from the onset.
These arrangements may include a clear set of guidelines for the creation of a network (registered, exempt, embedded or otherwise) that sits between the new and future assets, and the existing NSP and common point of coupling (see below for suggestions).

Brownfields development

For existing arrangements, create a clear ‘rubber stamping’ process for moving the point of connection to the MV side that does not introduce risk on the part of the standing asset, particularly with relation to any renegotiation of the existing GPS.

</td></tr>
<tr><td colspan="2">See Figure 1 and Figure 2 below, outlining the before and after regulatory arrangements for the Gannawarra Solar Farm (GSF) and Gannawarra Energy Storage System (GESS) that highlight the changes alluded to above.</td></tr>
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Figure 1 Regulatory arrangements for the Gannawarra Solar Farm (GSF) before the introduction of the Gannawarra Energy Storage System (GESS)

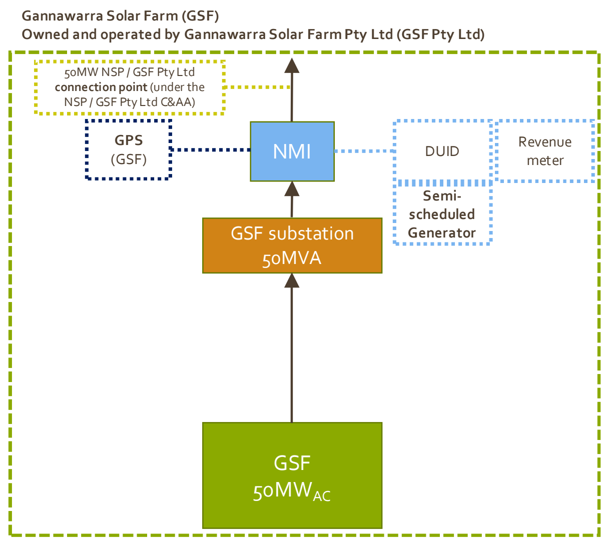
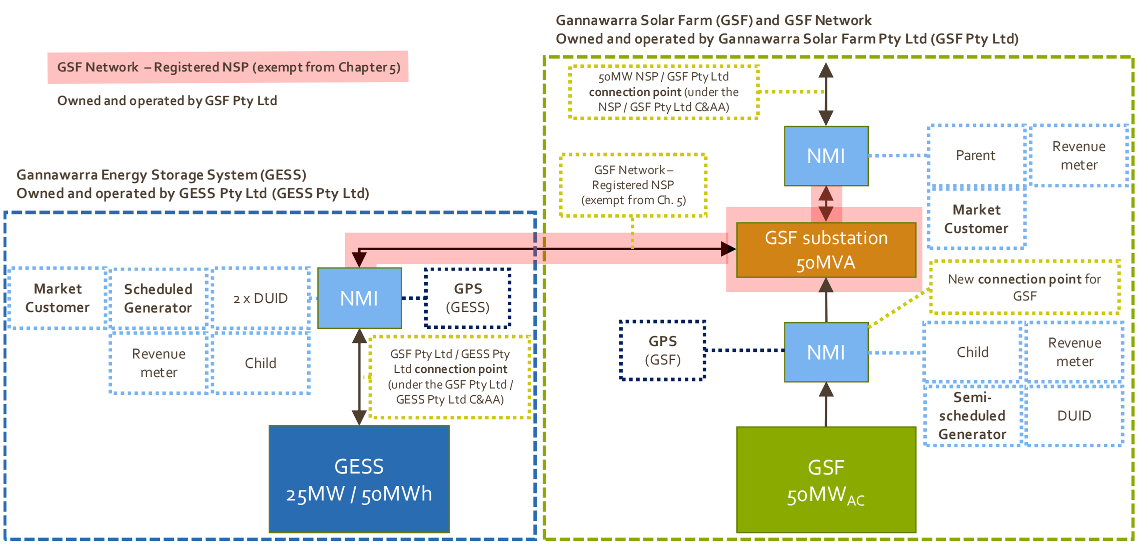


Figure 2 Regulatory arrangements for the combined GSF and GESS systems connecting into a common substation



2. *Clarity in the creation of networks*

Issue	Solutions

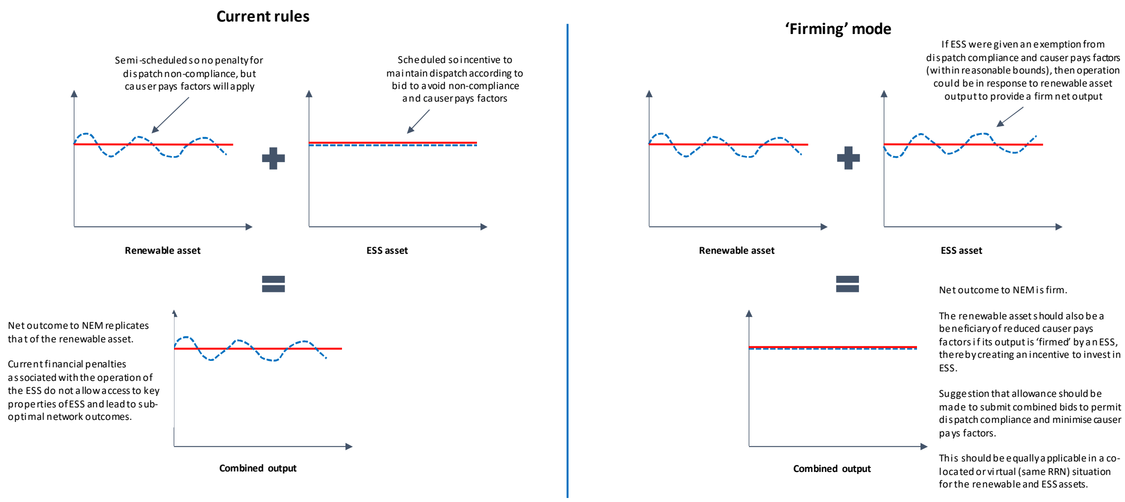
• As alluded to above, placing a point of connection between a substation and a NSP creates a network.
    ○ In the case of GSF and GESS, this was a registered network not an embedded network so that AEMO was able to ensure GPS enforceability rights (Edify Energy acknowledges that this is something that is looking to be addressed as part of this stakeholder consultation).
	• Create a clear 'rubber stamping' process for the creation of networks used for this purpose with:
	    ○ Known exemptions from Chapter 5;
	    ○ Template NSP-NSP connection agreements / standards;

• The network that is created in this case (i.e. a substation and cabling) is conceptually removed from what is intended by a network (i.e. mass conveyance of power over large distances) • Moreover, project SPVs do not make natural NSPs and have the capacity or capability to take on the obligations associated with being one. • For this reason, exemptions from elements of Chapter 5 of the NER are required in a relatively complicated process that requires individual negotiations with the connecting NSP and the AER. • Particularly in the case of negotiating NSP-NSP Connection Agreements / Standards, there is unlikely to be consistency across the NEM in undertaking this. • It also gives rise to complicated commercial arrangements between the assets connected into the new network, particularly concerning the allocation of prudential requirements, responsibility for import tariffs from the upstream NSP, and the ambiguity and beneficiary of avoided TUOS payments that may be payable by the upstream NSP (in the case of this being a distribution network).	○ Seamless allocation of prudential requirements and pass-through of network charges to the party responsible (usually battery as large consumer); ○ Recognition that the standing asset in a retrofit situation should retain its existing network charge classification and not be penalised with a new tariff on account of the new asset; and ○ Clarity on the entitlement to avoided TUOS payments where the upstream NSP is a distribution network and the seamless transfer of these avoided TUOS benefits to the correct asset in the new network.

3. *Classification that recognises the real-time firming attributes of ESS*

Issue	Solutions
• The classification of ESS as scheduled has the potential to limit its flexibility attributes in energy markets as could be applied at a sub 5-minute dispatch interval granularity. • This is particularly true with respect to ESS's potential to operate in tandem with a renewable asset and respond in real-time and in a converse way to its fluctuations to produce a combined output that is firm. • The application of the scheduled classification limits this 'firming mode' operation of the ESS as departures from a scheduled dispatch at a sub 5-minute dispatch interval granularity would result in a non-compliance breach direction. • This is a sub-optimal outcome for both the market and for the renewable asset: ○ <u>Market</u>: the wider market will be required to procure these firming services in any event, but via more expensive FCAS markets. By affording the right to ESS to firm in the energy market, there will be greater wholesale adoption of firm renewables and lower system FCAS costs; and ○ <u>Renewable asset</u>: the renewable asset will not be able to access an opportunity to procure a firming service to manage a hedge position or to assist in the management of causer pays FCAS factors. • Addressing this will unlock business cases for ESS and improve its deployment and contribution to improved market outcomes.	• Introduce a different classification (e.g. 'quasi-scheduled') that permits separate ESS and renewable asset generating systems to submit joint offer. • As a 'quasi-scheduled' unit, the ESS is permitted to depart from its scheduled dispatch at a sub 5-minute dispatch interval granularity for the purpose of firming. • Causer pays factors for the two assets are considered jointly. • Recognising the system security prerogative of AEMO, the ESS is only permitted to maximally depart +/- [x]MW or [x]% from its scheduled dispatch. • For the purpose of determining causer pays FCAS factors, these two assets are combined. • When not submitting a joint offer, the ESS should revert to a scheduled classification as normal. • The application of this classification should be technology neutral (i.e. equally apply to coal, say) but it is anticipated that a benefit will be derived in its ability to respond at 4 second granularity to address causer pays factors. • The application of this mode should be equally possible for both co-located systems exporting through a single connection point (e.g. GSF and GESS) as well as 'virtual' (physically separate) arrangements within the same RRN.
See Figure 3 below, outlining the application of 'firming mode'.	

Figure 3 The application of a 'firming mode' concept at sub 5-minute dispatch interval granularity



4. *Scheduled classification for hybrid single generating systems*

Issue	Solutions

• Where ESS is coupled with a renewable asset behind a single point of connection, the application of scheduled status for the generating system may be inappropriate.
• Depending on the relative proportion of ESS capacity (MW) and stored energy (MWh) to the capacity (MW) of the renewable asset, it may be challenging for the system to comply with its scheduled classification.
• For instance:
  ○ Where the ESS is full, it will be unable to manage an increase in output from the renewable asset;
  ○ Where the ESS is empty, it will be unable to manage a decrease in output from the renewable asset; and
  ○ Where the ESS is offline, it will be unable to manage any fluctuations in output from the renewable asset.
• This will impose a risk burden on the renewable asset that is challenging to manage and in doing so may create an impediment to investment of combined ESS and renewable generating systems.
	• Dynamic classifications should be considered, where either a scheduled or semi-scheduled classification applies to a system, dependent on its operating characteristics for the relevant dispatch interval.
	• For instance, where the ESS is full, empty or offline, the combined system reverts to a semi-scheduled status, otherwise, scheduled status applies.
	• Tolerances (i.e. approaching full or empty) would need to apply for this to work in practice.
	• For example, a dynamic classification metric could be established where, for any given dispatch interval, if the ESS is able to provide [x]MW or [x]% coverage to the renewable asset (in both charge and discharge directions) for the full 5 minutes, then the system is classified as scheduled, otherwise it is classified as semi-scheduled.

5. *Use of ESS for the management of curtailment in a local network*

Issue	Solutions
• Where a renewable asset is at risk of systemic curtailment (through the application of semi-dispatch caps), an opportunity should exist to use an ESS to capture any curtailed energy above the semi-dispatch cap for export at a later time. • At present, semi-dispatch caps are applied at an asset's connection point, which would prevent the use of a co-located ESS to capture curtailed energy in instances where the assets are registered as independent generating units. • Particularly where the business case for co-locating a battery is premised on capturing curtailed energy from an existing asset, it is	• Where a local network is created due to the presence of two independent generating units, there should be opportunity to apply a semi-dispatch cap at the common point of coupling with the surrounding network that is subject to the constraint event. • If for instance a 50MW solar farm has a 25MW semi-dispatch cap applied, this 25MW cap should apply at the network-to-network connection point,

highly likely that the system may be set up as independent generating units, similar to the retrofit GSF and GESS example. • Failure to address this, will prevent the adoption of a natural business case for ESS in the market (and risk mitigation measure for curtailed renewables) and limit opportunities to capture renewable energy that would otherwise have been usefully used.	thereby permitting the renewable plant to dispatch its full 50MW output, with the balance of the 25MW used to charge the co-located ESS.

Question 2: Do you have any views on whether a definition of ESS should be included in the NER?

Question 3: Do you have any views on whether a definition of ESS should be generic and encompass technologies other than batteries, for example, pumped hydro?

Edify Energy in principle supports the inclusion of a definition for ESS in the NER and to the greatest extent possible this should be agnostic to technologies. However, this agnostic approach needs to ensure it does not inadvertently become limiting with respect to the technical differences in technologies. For instance, the fast-acting nature of Li-ion battery technologies, if grouped with slower responding technologies such as pumped storage or flow batteries, may give rise to operational constraints on Li-ion batteries if the application of the definition and the differences in technologies are not dealt with correctly.

Question 4: Do you have any views on AEMO's suggested definition of ESS?

We do not have strong views on this definition.

1.2 Section 2.4.2: Participation and operation

Question 1: What are your views on the appropriate participation model for integrating ESS into the NEM?

Edify Energy agrees with approaches that are robust to both stand-alone ESS and hybrid ESS and renewables systems under a single framework. The proposed option 2a appears to seek to achieve this. However, there are two areas of concern that should be addressed when developing this option in further detail:

1. As alluded to in Section 1.1, the scheduled status of ESS (stand-alone and within hybrid systems) is problematic and should consider whether a blanket scheduled approach will ultimately constrain rather than enhance the potential for ESS to improve system security in a growing renewables environment; and
2. Any options developed should be robust to the retrofit scenario and recognise that today's technology options more readily allow adaptation of generating systems than in the past. For instance, the retrofit addition of ESS into a renewable generating system at a later date will become more commonplace decisions as market conditions evolve and ESS technology costs decline. Setting up a framework that allows the seamless adaptation of these systems in an understood and low risk way is paramount to unlocking the lowest cost options for deploying ESS.

Question 2: Would the proposed participation model (2b) meet your future needs, both in terms of participating in the NEM with an individual ESS or where multiple resources (e.g. ESS and generating units) are to be aggregated?

AEMO is particularly interested to understand the additional benefit that you would derive from aggregating hybrid systems and offering them to the market as a single resource that is not available by separately offering the components to the market.

As alluded to in Section 1.1, there are a number of benefits that ESS could provide, beyond just its ability to arbitrage energy across time and competitively participate in FCAS markets. These primarily relate to portfolio benefits (but do not necessarily require a single generating system), such as:

- The use of ESS to provide genuine (i.e. sub 5-minute dispatch interval) firming services to renewable assets, such that hedge positions can be better managed and to access an additional mitigation option for addressing causer pays factors. This should be permitted in both a physically co-located and a 'virtual' (physically separate but within the same RRN) scenario and could be applied by allowing joint submission of offers into energy markets; and
- The use of ESS to capture curtailed energy in a co-located situation within a local network by applying semi-dispatch caps at the common point of coupling to the constrained network and not at an individual asset's connection point, thereby allowing energy that would have been curtailed to be captured by the ESS for dispatch at a later time.

Question 3: Refer to Table 8, are there other potential challenges and risks associated with option 1?

Question 4: Refer to Table 9, are there other potential challenges and risks associated with options 2a and b?

Edify Energy's views on the additional potential challenges associated with stand-alone and hybrid ESS are expressed in Section 1.1.

Question 5: Do you have any views on AEMO's proposed approach to implement a single participation model to integrate ESS?

Edify Energy does not currently have strong views on the merging of generation and load offers for ESS into a single offer. However, in reading the stakeholder paper a single participation model does appear to introduce some challenges and complexities, particularly around managing differences in MLF and non-continuous resource considerations. Edify Energy therefore suggests due consideration is given to both the benefits and costs of making this change before it is implemented. If the sole benefit is preventing conflicts between generation and load offers, could a mandatory functional check be performed prior to submission of offers to prevent these conflicts. Particularly where offers from ESS will increasingly be made by automatic bidding computer software, the complexities of having separate generation and load offers may be manageable.

Question 6: Do you have any views on the proposed key requirements AEMO has identified for an ESS participation model?

With respect to a need to specify MWh, it is Edify Energy's position that this element of an ESS may be changed over time without the need to renegotiate performance standards or any other aspect of a project's connection or dispatch rights. For instance:

- Li-ion technology options will typically have a declining MWh profile over time; and
- Project developers / owners may seek to augment the stored MWh energy for an ESS should market or project conditions evolve that would warrant such a decision. For example, a 2-hour system may be augmented to become a 4-hour system, against the same MW inverter capacity.

This is akin to thermal technologies, such as the stockpiling of additional coal reserves on site.

Question 7: Do you have any views on whether existing ESS should be transitioned to the proposed participation model (2b)?

Provided risks that were not contemplated at the time of financing of the ESS are not introduced and the cost of making these transitions is nil, then Edify Energy is cautiously open to existing ESS transitioning to new arrangements.

2 Section 3: Other NEM improvements

2.1 Section 3.1: The application of performance standards to a generating system or load in an exempt network

Question 1: Are there other options to address the issue identified for connecting plant in an exempt network?

Question 2: Are there other costs, risks and benefits associated with the options presented? If so, please indicate what these are.

See Section 1.1 for Edify Energy's views on the use of networks for the introduction of ESS.

Question 3: Which option to address the issue is your preferred option? Why?

No response.

2.2 Section 3.2: Providing NEM information to project developers

Question 1: Should a person intending to develop or build a generating system or ESS (and not subsequently register as a Generator) be allowed to register as an Intending Participant?

Yes. Edify Energy sees this as a pragmatic change to the current arrangements.

Question 2: What is the market benefit associated with allowing a person intending to develop or build a generating system (and not subsequently register as a Generator) to be an Intending Participant?

Allowing developers (who hold the knowledge and risk of bringing projects to market) to access the information they require to perform this function is a more efficient use of capital and capability. It more seamlessly allows projects to access a lower cost of capital for the purposes of financing, which should lead to lower system cost outcomes.

Question 3: Referring to section 3.2.3, are there other options to provide a person intending to develop or build a generating system (and not subsequently register as a Generator) with the necessary NEM data?

No response.

Question 4: Are there other costs, risks and benefits associated with the options presented? If so, please indicate what these are.

No response.

2.3 Section 3.3: Separation of operational and financial responsibility

Question 1: What is the market benefit associated with allowing the separation of operational and financial responsibilities?

In addition to the points already identified, there is also the benefit of increased fungibility of assets. If for instance a single project has a blend of contracted and uncontracted positions and the owner wishes to sell, this concept allows cleaner delineation of the project and affords an opportunity to sell to multiple buyers (contracted to one and uncontracted to another, say). This improves the exit-strategy optionality on an incoming investor, thereby reducing project risk, the upfront cost of capital of the asset and the end-user cost of bringing this capacity to market.

Question 2: What are the risks associated with allowing the separation of operational and financial responsibilities?

The proposal to make the operational participant responsible for a default on a financial party is sound. However, the converse may be challenging. If the operational participant fails to meet its obligations, then each financial party will be exposed. Contracting arrangements between parties to cover this risk and assign responsibilities will need to be worked through.

Question 3: Are there other models of separate operational and financial responsibilities that should be considered?

No response.

2.4 Section 3.4: Logical metering arrangements

Question 1: What is the market benefit associated with using logical metering arrangements?

It better allows the application of models associated with the separation of operational and financial responsibilities to existing facilities that do not already have NMI compliant metering in place at a disaggregated level.

Question 2: What are the risks associated with allowing the use of logical metering arrangements?

No response.

Question 3: If logical metering arrangements are permitted to be used instead of a NER compliant metering installation, who should pay for this? Please identify any cost recovery arrangements that you consider appropriate.

No response.