Clements Gap BESS SCADA Control Philosophy

PSD1834-200-009

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1. Introduction

1.1. Purpose

The purpose of this document is to describe the high-level control requirements for Clements Gap BESS (CG BESS) related to AEMO functionality implemented in the SCADA/EMS/PPM.

Depending on the nature of the project, AEMO market dispatching can come either via the TNSP or via the asset owners market dispatch system. CG BESS will more than likely have both systems however the market dispatch system via the asset owner is considered as a future requirement.

The substation gateways interface to Transmission Network Service Provider (TNSP) and market system that will be provided by Pacific Blue Semi-Dispatch Management System (PBSDMS). Setpoint Targets from AEMO will be provided to the gateways by one or both interfaces and intern the gateways will pass these setpoints onto the Energy Management System (EMS) controller to ensure the BESS follows these setpoint requirements. As the BESS can be both a load and generation system control of the target power and voltage/Var, it needs to be controlled by Australian Energy Market Operator (AEMO) and the TNSP to meet NEM regulation requirements.

CG BESS will participate the following AEMO/TNSP control schemes, namely: -

- Active power control schemes (AGC and Dispatch Scheme),
- Reactive power control scheme (VDS VAr Dispatch scheduling scheme),
- Regulation Frequency Control Ancillary Service (applied through AGC).

It is our understanding that CG BESS is defined as a “Target Aggregate” for dispatch conformance in accordance with clause 2.6.3 of SO_OP_3705 [Ref 2].

The following AEMO control schemes are not considered in this document: -

- Contingency FCAS
- Transmission Line limits and runback schemes

The focus of this document is on the process and conceptual aspects of the control requirements and does not delve into the specifics of the AEMO NEMDE configuration or the detailed specifications of each scheme or interface. This document is intended to ensure the control requirements align with the AEMO/TNSP regulations and EMS/PPM requirements. This document does not detail any of the EMS control functions.

1.2. Background

Clements Gap is an operating wind farm owned by Pacific Hydro in South Australia and is located within the Barunga Ranges on farmland in the Mid North region of the State. The wind farm is comprised of 27 Suzlon 2.1MW wind turbines with a total installed capacity of 56.7 MW. Clements Gap substation is the wind farm substation which connects to the 132 kV transmission network via an ElectraNet owned 132 kV switchyard named Red Hill substation.

The 60 MW/ 120 MWh Lithium-Ion type Battery Storage System (BESS) facility is proposed to be located adjacent to the existing wind farm substation, at the new Clements Gap BESS substation.

1.3. Hold Points

None

2. Standards & specifications

2.1. Applicable Standards

The main standards relating to the equipment within this specification are:

Table 1 – Reference Documents

Drawing / Document Number	Rev	Description
12546421-SPC-001	2	Pacific Hydro Clements Gap BESS BESS Technical Specification
12546421-SPC-003	2	Pacific Hydro Clements Gap BESS BESS Substation and BoP Specification
TCA	NA	ElectraNet TCA Appendix A - Scope of Works
SO_OP_3705	94	AEMO Dispatch procedure
ESOPP_12	8.0	AEMO Market ancillary service specification
NC-GDLN-0007	1	AEMO Communication System Failure Guidelines
RFI #157	-	AEMO Market Interface
PSD1834-200-012	0	Cyber Security Risk Assessment
PSD1834-200-017	0	Emergency Shutdown Procedure
PSD1834-200-018	0	Control System Testing Procedure

2.2. Abbreviations

Terminologies and abbreviations used throughout this document are listed below.

Table 2 – Terminologies and Abbreviations

Abbreviations	Description
ADG	Aggregated Dispatch Group
AEMO	Australian Energy Market Operator
AGC	Automatic Generation Control
BESS	Battery Energy Storage System
BoP	Balance of Plant
ControlNet	AEMO's SCADA System
DNP	Distributed Network Protocol
DUID	Dispatchable Units ID
EMS	Energy Management Systems
EMMS	AEMO Electricity Market Management System
FCAS	Frequency Control Ancillary Services
HMI	Human Machine Interface
MarketNet	AEMO's Private Network Available to Participants having a Participant ID
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NLCAS	Network Load Control Ancillary Services
PBDMS	Pacific Blue Dispatch Management System
POC	Point of Connection
PPC	Power Plant Controller
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
TNSP	Transmission Network Service Provider – As referred ElectraNet in this project
TNU	Transmission Network User
VDS	Var Dispatch Schedule

3. Control Scheme Overview

3.1. Control Components

The control system has various components facilitating various aspects of the control system. The primary components of the control system are:

- Substation Gateways - Interface between TNSP, HMI, Market and the EMS controllers,
- EMS Controllers – Overall Control Coordination of the plant. Communicates with the substation gateways and the PPM.
- PPM – Closed loop controller for the BESS and inverters, dispatching BESS generation in accordance with the requirements of the grid and the dispatch instructions.

3.2. Control System Components and Connections

Components of the control system are as follows:

Table 3 - Control System Components

Component	Product / Manufacturer	Function Description
Substation Gateways	SEL-3555	Provides communication interface facilities between AEMO/TNSP and HMI to the control system (EMS/PPM).
EMS Controller	Trina/Univers EnOS Storage Master Controller (ECU-4784)	Provide upper-level control co-ordination overseeing the PPM controller. Key functions include: - Dispatch Instruction Following: Ensuring compliance with operational directives. - Change Rate Control: Managing variations in output. - Planning Curve Management: Optimizing energy usage according to forecasts. - Primary Frequency Regulation: Maintaining grid stability. - Power Prediction Compensation: Adjusting for forecasted power needs. - Reactive Power Regulation: Supporting voltage stability across the system.
PPM	SMA PPM-10 Hybrid Controller	Closed loop controller used for generation control. Receives commands from the EMS controller and dispatches them to the inverters. Control power flow at the point of connection. Note: PPM metering is connected to dedicated CT and VT connections. No additional PQM required.
Inverter	SMA SCS 3600 UP	Inverter converts DC to AC in accordance with the instructions received from the PPM.
Battery System	Elementa G2 8 Racks and 10 Rack systems BMS Controller (BLU)	Charges / Discharges in accordance with instructions received from inverter.

Connections between the control systems:

Figure 1 shows the communication architecture for the control scheme. AEMO will issue instructions / dispatch setpoints via the TNSP interface (ElectraNet) to CG BESS.

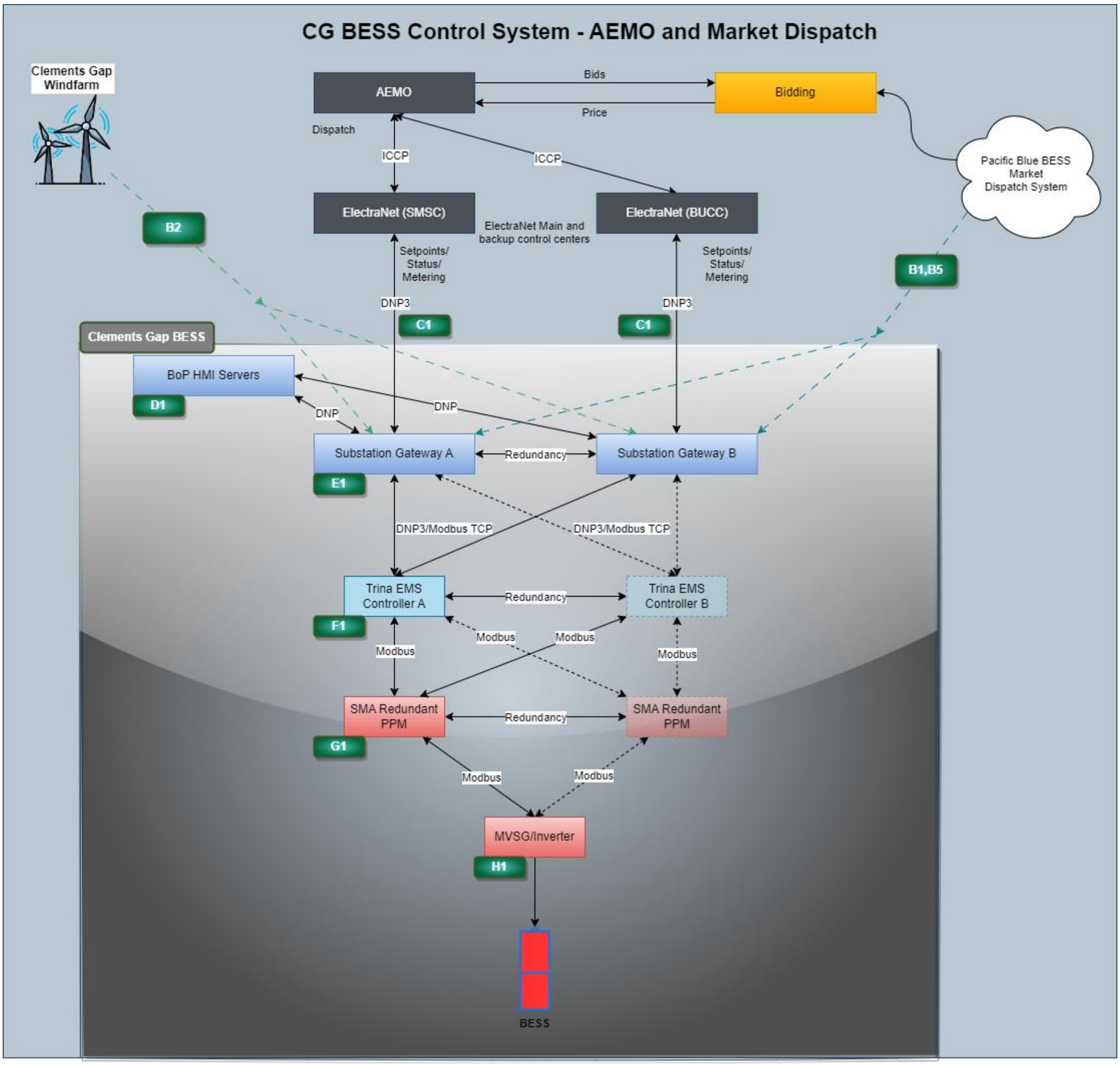


Figure 1 - CG BESS Control Scheme

C1 – The TNSP (ElectraNet) will communicate using DNP3 TCP/IP to CG BESS substation gateways. This comms channel will include the AEMO control information for dispatch, AGC and VDS. Indications from the plant will be provided back to AEMO via this interface. ElectraNet have redundant DNP comms channels. SMSC connects to substation gateway A and BUCC connects to substation gateway B. Only one of these channels is active at any given time. Therefore, the EMS controller will have to accept a DNP connection from either gateway A or gateway B at the same time.

B1,B5 – In accordance with RFI 156, this interface represents the market interface provided from Pacific Blue. This interface will provide dispatch setpoints and transmission line limits.

B2 – This interface represents the connection to the existing Clements Gap windfarm. From a AEMO control perspective the windfarm and CG BESS are completely independent generation resources. There may be a future requirement (based on the line limit) that generation from the windfarm will need to be considered. However, this is a future requirement.

D1 – The BoP HMI will provide local control of the plant and also display and capture historian information. The BoP HMI is redundant and will have dual DNP connections to the substation gateways. Not all connections are detailed here.

E1 – The substation gateways will have communication connections to TNSP, BoP HMI, and EMS controllers amongst others. The gateways operate in a Hot-Hot configuration.

F1 – Trina EMS controllers will provide the high-level control of the BESS. These controllers are in a Hot-standby configuration. The EMS controllers will receive AEMO setpoints from the substation gateways and dispatch them to the SMA PPM controllers.

G1 – SMA PPM hybrid controllers will be responsible for controlling/dispatching the BESS. The VT and CT inputs will be wired directly to them, which will provide the fastest response for contingency FCAS. The PPM will communicate with the inverter controllers, to control the BESS plant.

H1 – The SMA inverters receive setpoints from the PPM controllers. The inverter converts the DC from the BESS to AC in accordance with the setpoints, either charging or discharging. The Inverters will communicate with the BESS.

4. Control Levels and Interface Selection

4.1. Control Levels

It is expected that CG BESS will have three levels of control, namely: -

Level 1 – EMS / PPM will have local control facilities to operate the plant. This is not the expected level that plant should be operated at.

Level 2 – BoP HMI will be able to provide local facility control via the substation gateways.

Level 3 – AEMO/TNSP/Market systems will provide network level control of the plant.

4.2. Interface Selection

CG BESS facility control interface selection will either be manual (HMI) or TNSP or Market Interface. Selection of the interface to be used will be up to the operator via the HMI either locally or remotely. This is a manual selection and does not have any automated logic based on communication failures.

Operator selection is defined as: -

1. Dispatch Source (TNSP Interface, Market Interface)
2. AGC Source (TNSP Interface)
3. P/Q/V/PF setpoints - Local HMI
4. VDS (TNSP Interface)

5. Active Power Control

This section details all the active power control requirements and the participation schemes for CG BESS substation gateways, EMS and HMI.

5.1. General Introduction of Active Power Control

AEMO provide two active power schemes, Dispatch and AGC. The dispatch scheme operates in a 5-minute cycle and the AGC scheme operates in a 4 second cycle. While the dispatch active power setpoint is transmitted to the substation gateway through two interfaces as listed below, with the dispatch source is manually selected via BoP HMI: -

- TNSP (ElectraNet) communication interface,
- Pacific Blue Dispatch Market interface (Dispatch Mode Only).

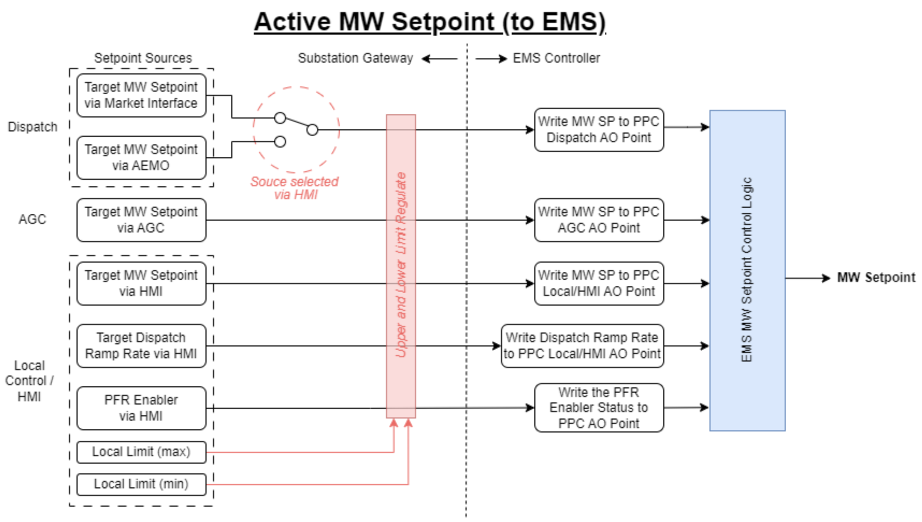
It is expected that the EMS controller will have three modes for active power namely: -

- AGC Mode,
- Dispatch Mode,
- Local Mode (HMI Control).

Control of all three modes is managed manually from the BoP HMI. Only one mode can be active at any given point. The operator can set the HMI to a specific mode when all the permissive conditions are all met, or select a setpoint source for dispatch participation, the EMS shall follow the relevant setpoints accordingly. Specific requirements for these schemes will be detailed in the following sections.

The EMS should have three analog output points for storing the active power setpoints (Dispatch, AGC and Local modes). Whichever setpoint is received from AEMO, or market interface, or HMI, will be written to the applicable analog output to the EMS. Figure 2 shows the base logic in the gateway for receiving the active target power setpoint and how it will issue this to the EMS controller.

Figure 2 – Active MW Setpoint



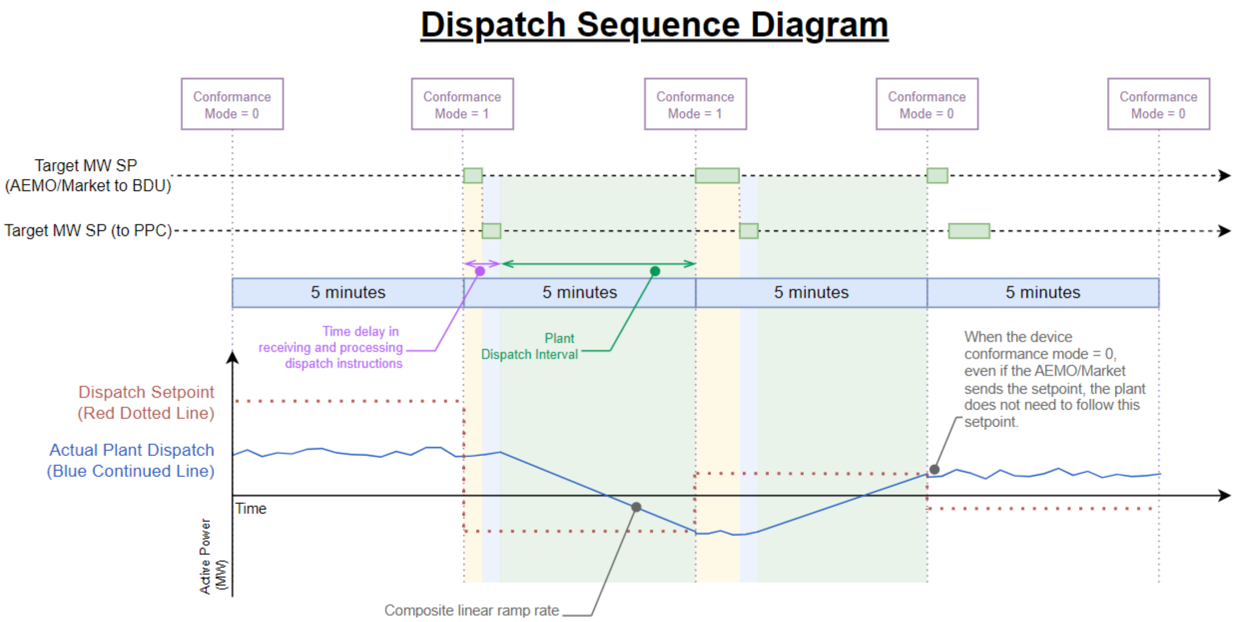
5.2. Dispatch Scheme

When EMS is selected in “Dispatch Mode”, the BESS will engage in the AEMO 5-minute dispatch scheme to provide active power response to grid. This 5-minute response will be adjusted based on the PBDMS bids submitted by AEMO’s NEMDE, and other grid constraints.

It is important to note that there are two potential sources for dispatch setpoint, which the operator can select specific one to follow via the HMI. Once selected, the gateway forwards the relevant interface's setpoint and other parameters (if required) to the EMS’s analog output point and discard the other interface's received values until the source is changed. There is no automatic fail-over mechanism for source selection.

Figure 3 details the dispatch sequence that should be followed as set out by AEMO.

Figure 3 – Dispatch Sequence Diagram



In the dispatch scheme, AEMO requires the participated plant linearly ramp up or down over the 5 min trading interval, this ramping should start from the initial active power at the time the dispatch instruction is received and aim to reach the dispatch target by the end of the time interval.

AEMO conducts an internal conformance calculation to assess the compliance of the plant with the dispatch scheme. If the plant fails to reach the target setpoint within the required timeframe or deviates beyond/below the acceptable threshold, AEMO will flag the plant, potentially affecting its eligibility to participate in the dispatch schedule.

Given that there are communication delays between when AEMO issues the target MW setpoint and when the EMS sees the setpoint from the gateway, the receipt of the target MW setpoint does not exactly follow the 5 min time interval in practical. It is the responsibility of the BESS EMS to calculate the effective ramp rate considering the time delays.

5.2.1. Control Signals

To implement the dispatch scheme, the following signals in Table 4 must be deployed in the substation RTU, BoP HMI and EMS. The actual tag names of the signals may vary depending on the interface or system, but the actual functionality of the signals must be consistent and approved by all parties prior to deployment.

Table 4 – AEMO Dispatch Scheme Control Signal List

<table>
<tr><th>Signal Tag</th><th>Function Description</th><th>Tag Type</th></tr>
<tr><td>ACTIVE_MW_TARGET (MASP)</td><td>The active MW setpoint that received.</td><td rowspan="3">Analog</td></tr>
<tr><td>CONFORMANCE_MODE[1]</td><td>For a Target Aggregate the conformance mode will always be set to 1.

There might be instances where this mode be set 0 by AEMO. In such cases, even if AEMO/Market issues the setpoint to the plant, the plant can discard the received setpoint.</td></tr>
<tr><td>AEMO_LINK_HEARTBEAT</td><td>Link health monitoring signal.
This signal shall be a periodic incremental signal between 1 and 10000, triggered by TNSP. AEMO will reset the link to 0 and start counting again. As long as the count is changing the heartbeat is considered valid</td></tr>
</table>

For more details about the link heartbeat signals and how to determine the interface communication conditions for each Dispatch source, refer section 9 for information on the substation communication failure detection mechanism.

5.2.2. Control Logics

To select EMS to dispatch mode via the TNSP / Market interface, the following conditions must be met:

Figure 4 - Dispatch Mode Control Logic

Inputs	**Gate Logic**	**Output**
BoP HMI Enable Dispatch (TNSP / Market) Line CB Closed EMS Comms Healthy AEMO/TNSP or Market Comms Healthy	AND	Enable Dispatch Mode in EMS Controller

5.3. AEMO AGC Scheme

The CG BESS will be registered as both a Generation unit and a Load of AEMO and will participate in AEMO AGC 4-second cycle if the conditions are met.

AGC control from AEMO also uses dispatch instructions, however this is generally used for small step changes and ramp rates are determined by EMS. If regulation FCAS is applied, then changes due to the regulation FCAS system are also added into the target AGC MW setpoint.

5.3.1. Control Signals

To implement AGC, the following signals must be deployed in the substation RTU, BoP HMI and EMS. The actual tag names of the signals may vary depending on the system, but the actual functionality of the signals must be consistent and approved by all parties prior to deployment.

Table 5 – AEMO AGC Scheme Control Signal List

Signal Tag	Function Description	Tag Type
AGC_CONTROL_MODE	Indication the BESS is ready for AEMO AGC control. • 0 := AGC / On • 1 := Local / Off *See next page for the point clarification.*	Digital
AGC_AVAILABLE_FOR_AGC	Indication the BESS is available for the AGC control. • 0 := No / Not Available • 1 := Yes / Available *See next page for the point clarification.*	
TOTAL_ACTIVE_POWER	Current BESS total active power measurement.	Analog
TOTAL_REACTIVE_POWER	Current BESS total reactive power measurement.	
UNIT_HIGH_LIMIT	Current BESS active power limit (high and low), which AGC will drive the unit with respect to these limits.	
UNIT_LOW_LIMIT		
RAMP_UP_RATE	BESS ramp up rate of change.	
RAMP_DOWN_RATE	BESS ramp down rate of change.	
MW_TARGET	AEMO AGC send the MW target value, also been known as the setpoint. It will not be a delta value, but either an energy target (when not regulation) or energy target and regulation requirement inclusive (when regulating)	

In this project, AGC setpoint will be sent continuously through the TNSP interface. Therefore, the AGC setpoint trigger will serve as the scheme's heartbeat indication. For information on the loss of the heartbeat signal and comms failure detection mechanism, refer to section 9.

Two separate signal points are required for AGC scheme participation prerequisites, AGC_CONTROL_MODE and “AGC_AVAILABLE_FOR_AGC. To better clarify and distinguish them, their details are outlined below:

- *AGC_CONTROL_MODE*

This point will be set to “AGC / “On” only when the following conditions are met:

Figure 5 - AGC Control Mode Feedback Logic

Inputs	Gate Logic	Output
EMS in AGC Mode No MW Discrepency Alarm Line CB Closed	AND	AGC CONTROL MODE (Feedback for AEMO)

Otherwise, the point will be set to “Local” / “Off,” which the BESS is not ready for AGC control. It shall be noted, the “Local” here is viewed from an AEMO/TNSP perspective, which not the true local control mode of the BoP HMI / EMS / PPC.

- *AGC_AVAILABLE_FOR_AGC:*

This point is controlled by the current selection of the plant's active power control mode, indicating the operator and plant's intention to participate in the AGC scheme. The point shall be "Available" when the EMS is in "AGC" mode with no active power mode discrepancy alarm. Otherwise, it shall be "Not Available."

Figure 6 - AGC Available For AGC Feedback

Inputs	Gate Logic	Output
EMS in AGC Mode No MW Discrepency Alarm	AND	AVAILABLE FOR AGC (Feedback for AEMO)

5.3.2. Control Logics

To select the EMS to the AGC mode, the following conditions shall be met: -

Figure 7 - AGC Mode Control Logic

Inputs	**Gate Logic**	**Output**
BoP HMI Enable AGC (TNSP) Line CB Closed EMS Comms Healthy AGC Comms Healthy	AND	Enable AGC Mode in EMS Controller

5.4. Frequency Control

CG BESS will participate in the contingency FCAS market. Contingency FCAS is outside of this document but will be implemented in the EMS/PPM controllers.

5.5. EMS P Mode Selection

There shall be one 4-way selection button configured on the BoP HMI for the active power control mode selection. The Table 6 below shows the mapping between the BoP HMI button selection and the EMS control mode.

Table 6 – BoP HMI – EMS Active Power Control Mode Mapping

BoP HMI Option	Description of the BoP HMI Selection	EMS Active Power Control Mode (Facility Active Power Control Mode)
AGC Mode	Participate in AGC Scheme	[1] Manual AGC
Dispatch Mode – TNSP	Participate in Dispatch Scheme and use TNSP Interface as the Source	[2] Manual DISPATCH
Dispatch Mode – Market	Participate in Dispatch Scheme and use Market Interface as the Source	
Local Mode	Active Power Local Control Mode	[3] Local (HMI)

All these active power control modes are mutually exclusive and EMS does not retain memory of previous states. There is no automatic mode switching configured in the substation gateways. Some more details of each Active Power control mode are listed below.

- *AGC Mode*

When operator selects the "AGC mode", the plant shall still continuously receive the 5 min Dispatch signals from AEMO/TNSP but should not implement them.

- *Dispatch Mode and Source Selection*

When the EMS is in "Dispatch Mode", it will maintain the plant in this mode regardless of whether the current dispatch source fails. However, in the event of the source failure, such as the heartbeat failure, the relevant alarm shall be raised on the BoP HMI to warn the operator of the problem.

- *Facility Local Mode*

In "Local Mode", the EMS will adhere to the local MW setpoint, local ramp rate, and PFR enabler status for plant operation.

It is important to note that the "Local Mode" here is **only** for the local control of **Active Power**. If the plant is also involved in other non-active power schemes, such as the VDS scheme, the plant shall still output the relevant reactive power (or voltage, or PF) according to the received setpoints. An alarm shall be raised when the Operator selects local mode.

The CG BESS bump less control is managed by the EMS. This configuration ensures the plant does not make any abrupt setpoint changes when the operator switches between modes, allowing the plant to transition smoothly between modes.

5.6. Active Power Discrepancy Alarms

During operation, several discrepancy alarms are generated for the active power control of the BESS plant when any contingency occurs. The actual tag names of the signals may vary, but the actual functionality of the signals shall be consistent.

Table 7 – Active Power Control Discrepancy Alarm List

Signal Tag	Function Description	Tag Type
MW _MODE_ DISCREPANCY_ALARM	When substation gateways send the mode control command to the EMS and receive the current operating mode feedback from it, if the mode on the EMS differs from the selection expected by the gateway for longer than 10 seconds, this alarm is generated. • 0 := Off / Cleared • 1 := On / Alarm	Digital
ACTIVE_MW_SETPOINT_ DISCREPANCY_ALARM	When substation gateway sends the setpoint to the EMS and receive the current setpoint feedback, if the setpoint on the EMS differs from the gateway for 1% and lasts more than 10 seconds, this alarm is raised. • 0 := Off / Cleared • 1 := On / Alarm	
DISPATCH_SETPOINT_ DISCREPANCY_ALARM	This alarm only be available when both the TNSP and Market Dispatch interfaces are selectable and in good condition. The alarm will be triggered if there is a more than 1% difference between the active power setpoint of the market interface and the TNSP interface for more than 20 seconds. • 0 := Off / Cleared • 1 := On / Alarm	

6. Reactive Power Control

The EMS operates in three modes for active power namely: -

- Reactive Power Control Mode,
- Voltage Control Mode,
- Power Factor Control Mode.

The control of all three modes is exclusively from the BoP HMI.

It is our understanding that AEMO will only control delta voltage as part of the VDS scheme. V, Q and PF can be controlled via the HMI separately if required.

6.1. AEMO VDS Scheme

6.1.1. Control Signals

To enable CG BESS to participate in VDS, the following overarching signals must be implemented in the substation RTUs, BoP HMIs and PPCs. The tag names may vary, but the signalling functions must be consistent and approved by all parties prior to deployment.

Table 8 – VDS Scheme Control Signal List

<table>
<tr><th>Signal Tag</th><th>Function Description</th><th>Tag Type</th></tr>
<tr><td>AVAILABLE_FOR_VAR_
CONTROL</td><td>Indicates whether the BESS is currently involved in VDS control.
• 0 := Not Available / No
• 1 := Available / Yes
Control of this signal is ultimately managed via the BoP HMI.
See next page for the point clarification.</td><td rowspan="2">Digital</td></tr>
<tr><td>VAR_TIMING_SIGNAL</td><td>Time synchronization indication for AEMO Var Dispatch schedule cycles. In Auto mode, this is normally run every 15 minutes.
• 0 := Off
• 1 := On
The VAR timing signal can be ±5s either side of the setpoint. It is recommended not to use the VAR timing signal in any logic.</td></tr>
</table>

Signal Tag	Function Description	Tag Type
VAR_DEVICE_CONFORMANCE	Signal for AEMO to use for marking and indicate whether the generation unit is currently compliant with the Var Dispatch schedule programme. • 0 := No (not compliant) • 1 := Yes (compliant) Generation unit marked as "Non-Conformance" for more than **a number of consecutive** cycles will be removed from dispatch scheme and will require the BESS operator to manually report the cause of non-compliance to AEMO. In the case of non-AEMO regulated reactive power control, the BESS setpoint will come either from ElectraNet or manually by the operator. An alarm will be raised to indicate the operator to call AEMO control centre to work out the issue if the plant is not conforming. Setpoint will be blocked if plant is not conforming.	
DELTA_VOLTAGE_CHANGE (Setpoint & Feedback)	The delta voltage setpoint received from the AEMO when BESS is participating in VDS, and the current calculated setpoint of the BESS feedback to the AEMO, which will be used by the AEMO to determine equipment compliance.	Analog

The following is the details about one of the signal points in the Table 8 above:

- *AVAILABLE_FOR_VAR_CONTROL*

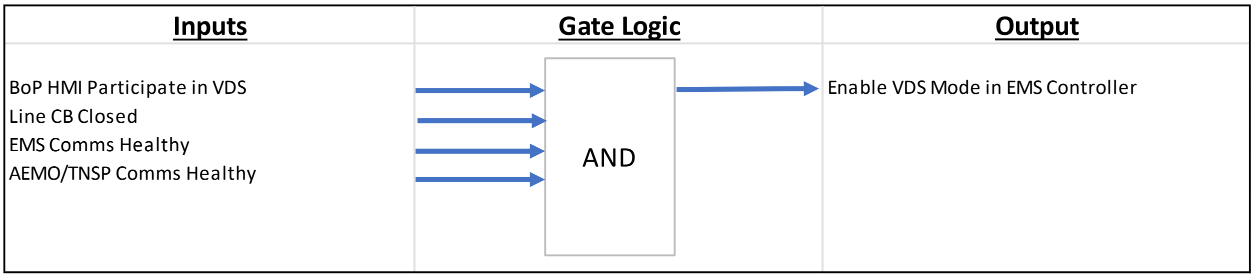
  This point is controlled by the current selection of VDS enablement, indicating the operator and plant's intention to participate in the VDS scheme. This point shall be "available" only when the operator sets the EMS to participate VDS via BoP HMI, and all permissive conditions are met, and the EMS feedback indicates "VDS Participation" is true. Otherwise, it shall be "not available".

For details on the link heartbeat monitoring for the VDS scheme, refer Section 9 for information on the substation communication failure detection mechanism.

6.1.2. Control Logics

To enable operator to select the VDS from the HMI, the following conditions must be met before executing control: -

Figure 8 - Enable VDS Scheme Logic



6.2. Reactive Power Discrepancy Alarm

During practical operation, like the discrepancy alarms for active power control, a series of discrepancy alarms dedicated to reactive power control are also configured at the substation gateway. The actual tag name of the signal may vary, but the function of the signal should remain consistent.

Table 9 – Reactive Power Control Inapplicable Alarm List

Signal Tag	Function Description	Tag Type
MVAR_MODE_ DISCREPANCY_ALARM	When operator select the BESS reactive power mode to the EMS and receive the current operating mode feedback from the EMS, if the mode feedback from the EMS differs with the selection expected by the gateway for longer than 10 seconds, this alarm is generated. • 0 := Off / Cleared • 1 := On / Alarm	Digital
MVAR_SP_ DISCREPANCY_ALARM	When substation gateway sends the setpoint to the EMS and receive the current reactive power setpoint feedback, if the setpoint on the EMS differs from the gateway for more than 1% and last longer than 10 seconds, this alarm is raised. • 0 := Off / Cleared • 1 := On / Alarm If the plant is set to participate in VDS, the actual voltage setpoint used for comparison with the voltage setpoint feedback will be the calculated value, with the sum of the previous voltage setpoint and the delta voltage setpoint (received from AEMO).	

7. Power Frequency Control

A PFR (Primary Frequency Response) enable/disable control point shall be configured in BoP HMI, allowing the operator to control the plant's frequency response mode, send feedback on its status as signal feedback to the TNSP and AEMO. The HMI will allow the operator to enable / disable the PFR for either charging and or dis-charging.

For this site PFR will normally be enabled for discharging and disabled for charging. The EMS controller will have to consider this in its control logic.

8. Network Loading Control

There is a future requirement to protect the transmission line limit for both CG BESS and Clements Gap Wind farm. This is a future requirement and has not been considered at this stage.

9. Link Heartbeat & Comms Fail Detection Mechanism

Several “heartbeat” signals are integrated into the CG BESS application based on required interfaces and the schemes involved. These heartbeat signals play the crucial roles to guide the plant into the appropriate operating state, ensure BESS functionality, and activate the system’s communication failsafe mechanism in the emergency scenarios.

The following Table 9 outlines the relationship between different sources of heartbeat signals and the corresponding schemes: -

Table 10 – Heartbeat Signals Matrix

Interface Name	From/To	Heartbeat Signal Description	Heartbeat Update Period	Action
AEMO/TNSP (ElectraNet)	TNSP/ Substation Gateway	*AGC/MW Setpoint Trigger*	4s/5m	Detection with 1 min but wait 10 minutes before raising alarm.
Market	Market/ Substation Gateway	Market Interface – “AEMO Heartbeat” Signal *Magnitude Increment*	Every 1 min with timeout of 10 minutes	Detection with 1 min but wait 10 minutes before raising alarm.
Substation Gateway	Substation Gateway/ EMS	COMM - DNP3 Link Heartbeat	Every 4s	Detection with 5s and raise alarm on BoP SCADA
EMS	EMS/ PPM	COMM - Link Heartbeat	Every 4s	Detection with 5s and raise alarm on BoP SCADA
PPM	PPM/ PQM	COMM - Link	Every 500ms	Detection with 500ms and ramp down BESS to 0MW/MVAr.
PPM	PPM Main/ PPM Standby	COMM - Link	Every 2s	Detection with 5s and raise alarm on BoP SCADA.
BMU	PPM/ BMU	COMM – Link Heartbeat	Every 1s	Detection with 500ms and ramp down BESS to 0MW/MVAr.

Redundancy and failover mechanisms:

Figure 9 details some of the redundancy and failover mechanisms for the entire control system.

CG BESS Control System - AEMO and Market Dispatch

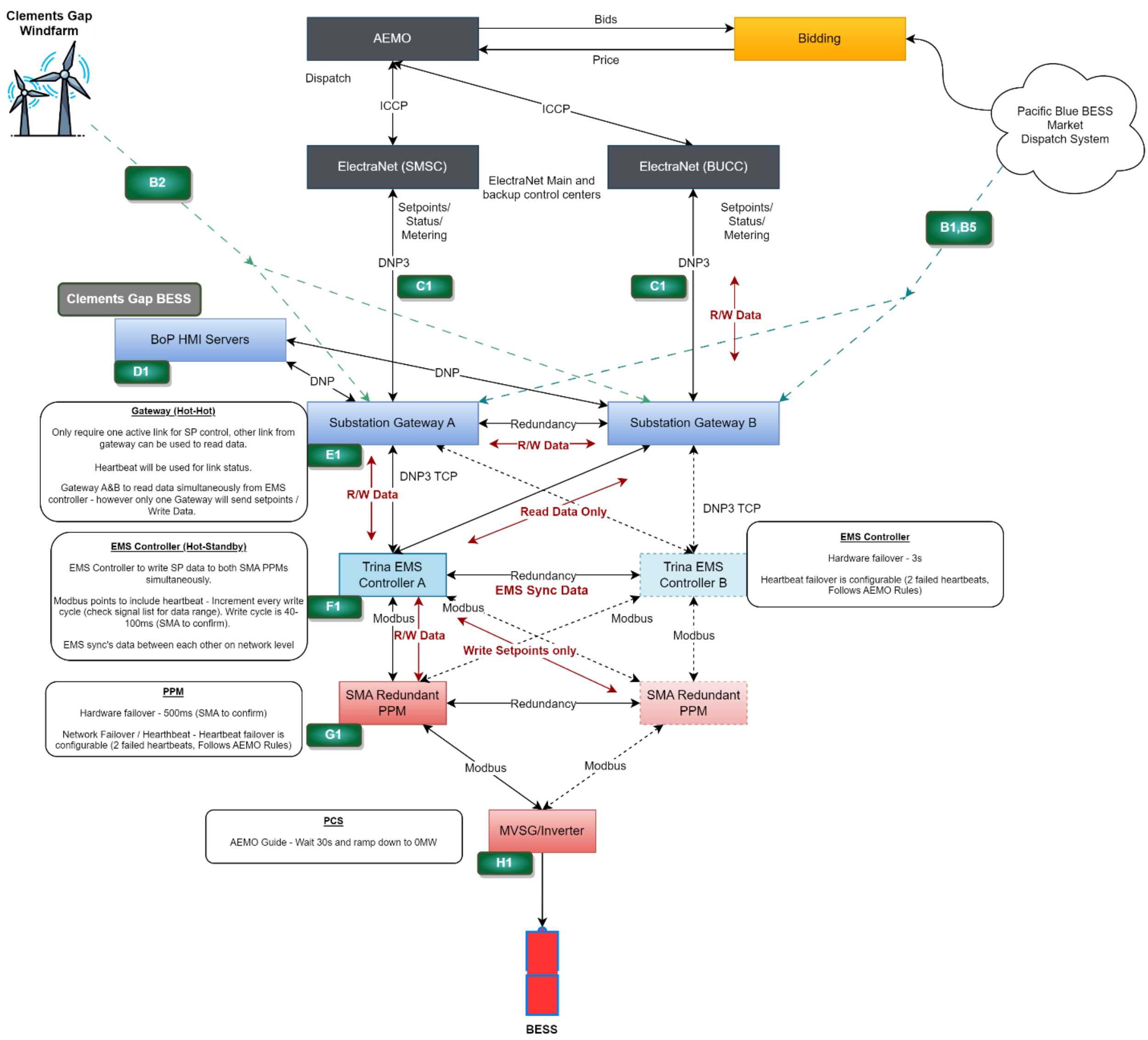


Figure 9 - Control System Redundancy and failover Mechanisms

10. Availability of the Control System

In accordance with AEMO – "Power System Data Communication Standard" dated 3 April 2023, the reliability of the control system for RCE/RME must meet the following criteria:

Table 11 – AEMO Reliability Requirements

Category of Operational Data	Max aggregate in 12 month period	Max per Critical Outage
Dispatch Data where there is no agreed substitute data	6 hours	6 hours
Dispatch Data where there is agreed substitute data	12 hours	12 hours

Based on the control system design, all components are fully redundant. Below is the calculation for the failure rates of the equipment.

Given we have 8 industrial computers / controllers in the system which is 8 x 8760 hours/year = 70,080.00 hours.

We assume a maximum of 2 failures every 5 years.

$$MTBF = \frac{Total\ operating\ hours\ of\ all\ control\ system\ componenets}{Total\ number\ of\ estimated\ failures}$$

$$MTBF = \frac{8 * 8750 * 5\ years}{2}$$

$$MTBF = 175{,}200.00\ hours$$

Expected replacement time, assuming spares are available is estimated between 4-16 hours. Take note that this does not mean the control system will be unavailable for this period. As all systems are redundant.

Power Backup is crucial for any control system, and the control system is fed from 10KVA UPS and will meet NER compliance of 3 hours standby time. A diesel generator on-site is available to supply emergency power to meet "Power System Data Communication Standard" of 12 hours.