Distributed Energy Resource (DER) Management for Wastewater Treatment Plant Using Redundant Centralised Control Scheme—A Case Study

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***Abstract*—In recent years, distributed energy resources (DERs) have increasingly been deployed onsite, enabling facilities to generate power for local consumption while also exporting surplus power back to the grid. This setup promotes self-sufficiency, enhances revenue and energy security, and supports environmental goals. To efficiently use onsite DERs, a centralised DER management system is required to monitor and manage power generation throughout the microgrid.**

This paper presents a practical approach to DER management that uses a centralised control system that includes functionalities such as active and reactive power control, islanding control, power flow control through the point of common coupling, and automatic synchronisation of the microgrid back to the utility.

The DER management system studied for this paper was implemented at a wastewater treatment plant, where onsite generation assets, which included a gas turbine, a steam turbine, and dual-fuel reciprocating engines. Intelligent electronic devices distributed throughout the plant collected and exchanged the necessary data to the redundant central controllers to support DER monitoring and control functions. A Parallel Redundancy Protocol-based network was deployed utilising an operational technology software-defined networking, offering a high-reliability Ethernet solution specifically tailored for critical infrastructure. Specialised monitoring software was used to record and analyse the response of the DER management algorithms during system commissioning.

***Keywords*—Auto synchronisation, DER management system, Ethernet network, generation control system, SDN network.**

I. Introduction

Reliable, economical, and stable power supply is essential for mission-critical facilities. This power supply can be achieved by integrating multiple renewable or nonrenewable distributed energy resources (DERs) within the facility. Managing these DERs requires a centralised control system that is intelligent, robust, and responsive to real-time conditions—commonly known as a power management control system (PMCS).

As defined in [1], a PMCS is an intelligent system with automated control functions designed to prevent, detect, and mitigate blackouts in both grid-connected and islanded modes. It manages key power assets to guarantee efficient economic performance, while gathering and analysing data to deliver actionable insights. The PMCS enables operators and engineers to diagnose events, conduct root-cause analysis, predict failures, and reduce unnecessary maintenance.

This paper presents a case study of one of North America's largest wastewater treatment plants, originally built in 1932 and upgraded in 2017 with a state-of-the-art PMCS. Acting as the system's central intelligence, the PMCS ensures seamless microgrid operation. The two key features of the system are the load-shedding system (LSS) and generation control system (GCS). While the LSS is detailed in [2], this paper focuses on the practical implementation of a GCS, which is responsible for DER management.

The paper is structured into several sections to offer a comprehensive understanding of centralised DER management. Section 2 outlines the facility's electrical system. Section 3 describes the PMCS architecture and DER interfaces. Section 4 details the GCS algorithms. Section 5 discusses implementation. Section 6 presents the results from a test scenario. Section 7 highlights challenges encountered during GCS deployment.

II. Facility Electrical Power System Overview

The electrical power system of the wastewater treatment plant is an industrial microgrid powered by two independent 13.2 kV utility sources and onsite DERs. These DERs include one 4.16 kV/4 MW gas turbine generator (GTG), three 4.16 kV/1.6 MW dual-fuel reciprocating engine generators (REG), and one 4.16 kV/1 MW steam turbine generator.

The facility operates at two voltage levels: medium voltage (13.2 kV and 4.16 kV), and low voltage (600 V). The independent utility feeders supply power to two separate buses at the 13.2 kV level, from which the voltage is stepped down to the two main 4.16 kV buses via step-down power transformers. The DERs are connected to dedicated 4.16 kV generation buses, which are linked to the two main 4.16 kV buses. These two main 4.16 kV medium-voltage buses supply power to medium-voltage aeration blowers and the process loads at the 600 V level.

All buses in the system are configured as double-ended main-tie-main systems and are interconnected to form the configuration shown in Figure 1. The 600 V voltage buses are not shown, as they are not within the scope of this case study.

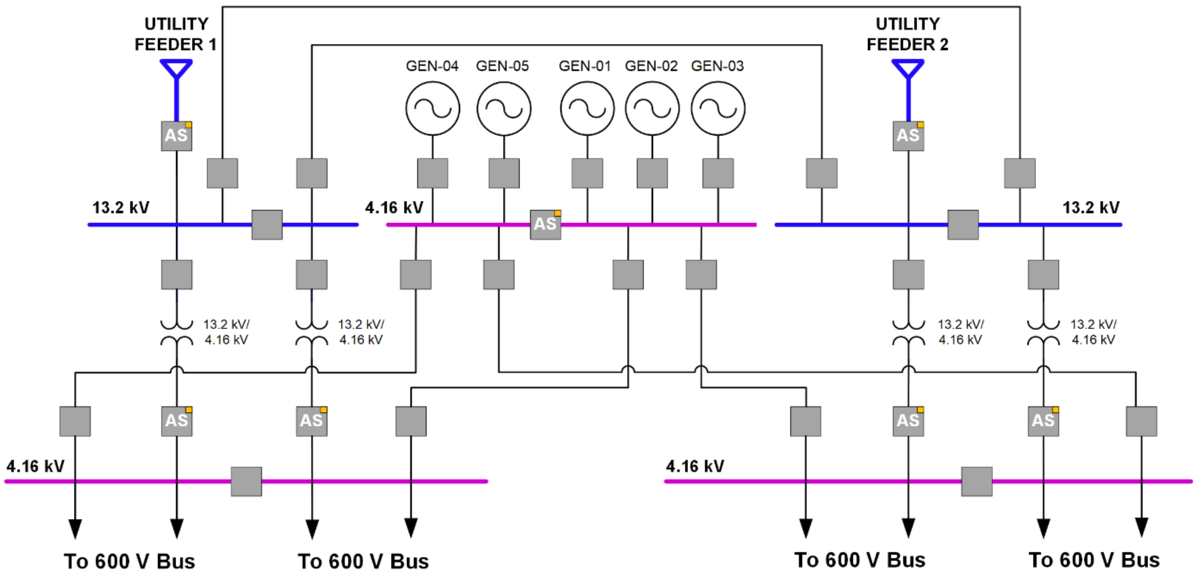

Figure 1 - Electric Power System Configuration of the Wastewater Treatment Plant

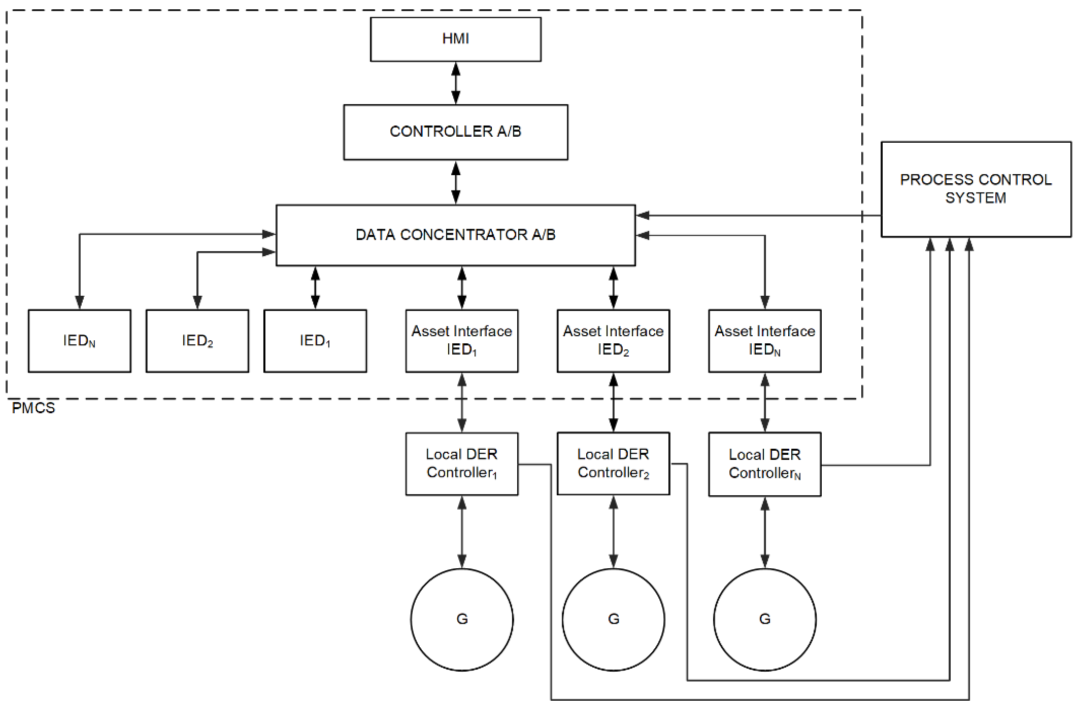

Figure 2 - PMCS Architecture

III. PMCS Architecture and DER Asset Interface

Figure 2 presents the simplified architecture of the PMCS. The intelligent electronic devices (IEDs) are distributed throughout the facility to gather critical field data from system assets like circuit breakers, transformers, motors, and DERs. The data are transmitted via high-speed and low-speed communications protocols, reliably and securely, through a purpose-engineered operational technology software-defined networking to the data concentrator (DCON).

The DCON collects and sends the field data to the PMCS controllers for analysis and decision-making. The PMCS controllers issue commands or set points to the IEDs to support the overall system objectives. The distributed IEDs form the foundation of the PMCS.

Each DER has a local controller programmed with the manufacturer's specific logic and input/output (I/O) to govern its behaviour. The proprietary GCS algorithm of the PMCS has I/O requirements to control the DERs and meet system objectives. To integrate a DER with the PMCS, an asset interface IED is used and programmed with custom logic to translate commands or set points between systems.

Open-loop testing ensures the local DER controller responds as intended. During this testing, active and reactive power set points are issued by the PMCS and the DER's response is monitored with specialised software. Based on the response, PMCS controller gain parameters are adjusted.

The goal is to align the DER controller's response with PMCS set points while maintaining stability, ensuring effective DER management.

IV. GCS – Functional Overview

As described in [1] [3], the generation control system contains various slow-speed control algorithms designed to correct different power system parameters, such as voltage, frequency, power flows, and power factor, which also provide support in system synchronisation.

A. *Automatic Generation Control System*

Figure 3 illustrates the automatic generation control (AGC) system. As described in [1] [3], the AGC system dispatches speed or MW set point to the generators' governors. Each governor's set points are established by the optimal load-sharing controller, which receives commands from either the frequency or tie-flow controller loops. The island detection logic within the island control system (ICS) decides which of these two loops is engaged.

B. *Voltage Control System*

Figure 4 illustrates the voltage control system (VCS). As described in [1] [3], the VCS system controls the exciter of the DER asset by issuing set points for equal reactive power load sharing, effectively controlling the voltage (V) and reactive power (Mvar) of the system. The overall operating philosophy of the VCS is similar to that of the AGC system.

C. *Island Control System*

As described in [1], the ICS controls the modes of the governors and exciters, and it tracks the number of islands in the system and generators connected to those islands. Additionally, it is an integral part of the autosynchronisation system, determining the two synchronising islands and the generators or utility connections to these islands.

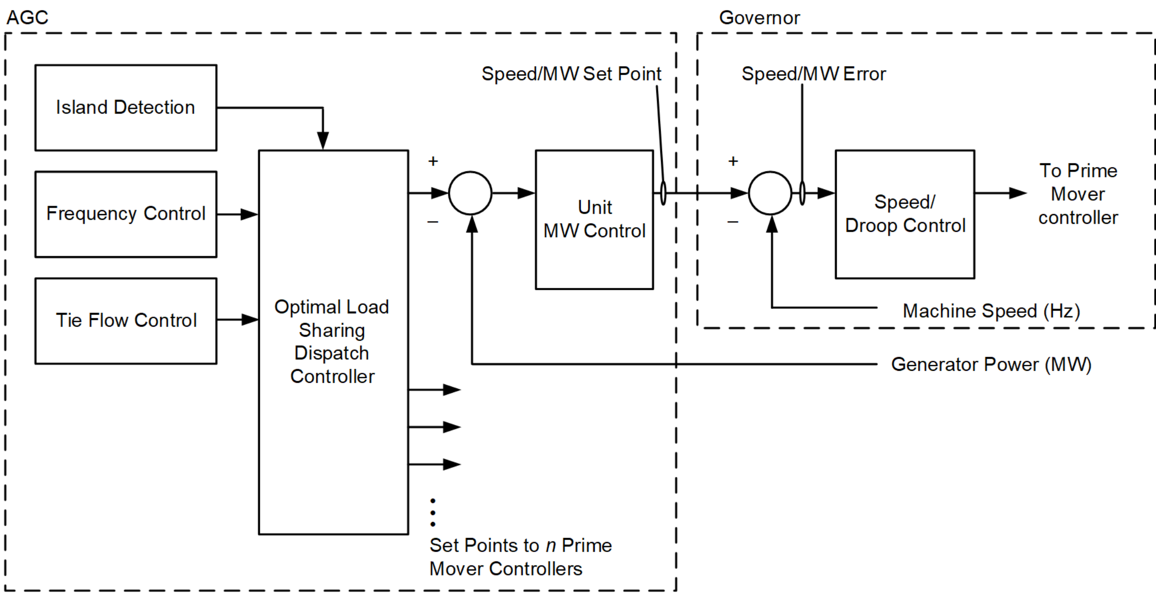

Figure 3 – Typical AGC System

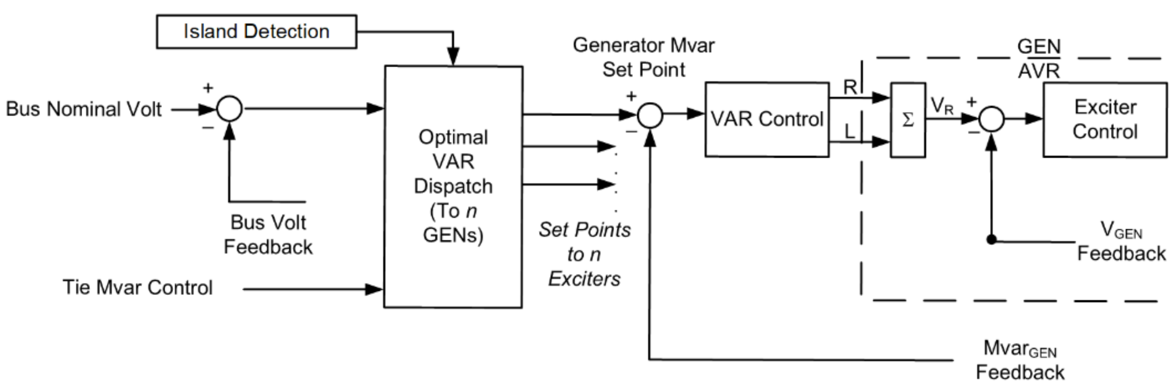

Figure 4 – Typical VCS

D. *Automatic Synchronisation System*

As described in [1], autosynchronisation (A25A) systems are essential for generators, tie-lines, and bus couplers. Figure 5 illustrates the A25A system. The field IEDs provide inputs to the topological tracking algorithm and the ICS. Island detection logic determines the configuration of the synchronising islands and controls the modes of the generators on the incoming bus. The A25A system measures the slip and voltage difference and sends this information to the GCS, which adjusts the governor and exciter to bring the slip and voltage within acceptable bands. The A25A uses slip-compensated advanced angle closing logic to ensure that the breaker closure is at a zero-degree phase angle.

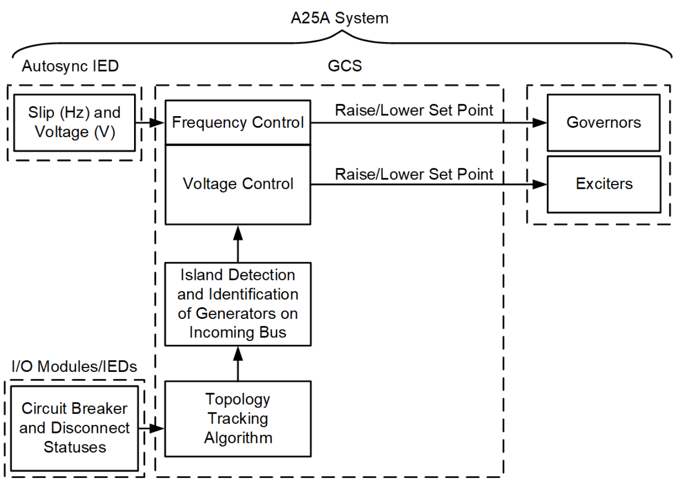

Figure 5 – Typical Automatic Synchronisation System

E. *Generator Capability Tracking System*

As described in [1], the GCS contains a generator capability tracking system that uses a least-value method to determine the allowable operational region for the AGC and VCS algorithms. The controllers are only allowed to dispatch a generator within the user-defined limits that form the boundaries of the operating region. This region is used to calculate the MW and Mvar spinning reserves for each unit.

Figure 6a illustrates an example where the user-entered regulation limits fall within the capability curve; however, the limits are outside the turbine limit (blue vertical line). Figure 6b demonstrates a scenario where the user-entered regulation limits extend beyond the generator capability curve and the turbine limit. In both figures, the allowable operational region is delineated by the red outline.

V. GCS – Implementation Details

A. *Selecting Governor Control Mode Based on Power System Configuration*

The local DER controller supports the following governor operating modes:

- Isochronous (ISOC): In this mode, the local generator controller acts to maintain the system frequency at nominal frequency. When operating in isochronous mode, the generator does not respond to the MW set points issued from the GCS.
- Frequency droop (FD): In this mode, the local generator controller responds to the MW set points from the GCS and adjusts its MW output according to a predetermined FD characteristic.

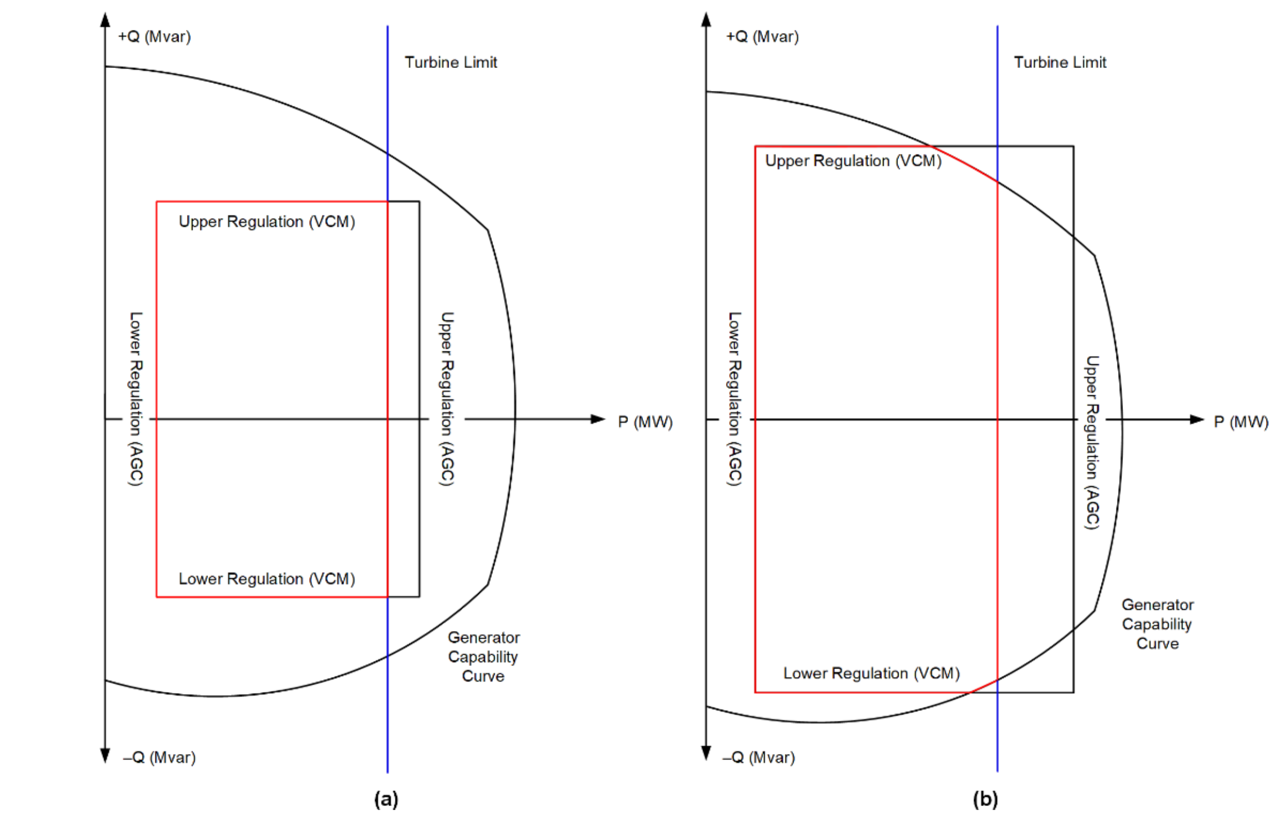

Figure 6 – a) Regulation Limits Within the Capability Curve and b) Regulation Limits Outside the Capability Curve

TABLE 1 - GENERATOR GOVERNOR CONTROL MODES

No.	Power System Configuration	REG			GTG
		GEN 1	GEN 2	GEN 3	GEN 4
1	GTG, REG and Utility (1 or 2) are in parallel	FD	FD	FD	FD
2	GTG parallel to Utility (1 or 2) and REG are parallel to Utility (1 or 2)	FD	FD	FD	FD
3	Islanded GTG and REG parallel to Utility (1 or 2)	FD	FD	FD	ISOC
4	Islanded REG and GTG parallel to Utility (1 or 2)	ISOC	FD	FD	FD
5	GTG and REG parallel and islanded	FD	FD	FD	ISOC
6	Islanded GTG and Islanded REG	ISOC	FD	FD	ISOC

For the power system shown in Figure 1, six operating configurations were identified. For these six operation conditions, the GCS controlled the governor control mode as defined in Table 1.

B. *Isochronous Unit Selection Priority*

Based on asset availability and priority the GCS selects isochronous mode for the DER. The isochronous priorities are hard-coded in the GCS algorithm. GEN 4 is Priority 1 while GEN 1, 2, 3 are Priority 2, 3 and 4, respectively. The largest rated generator should be used as the isochronous generator, as it can accept the most load without impacting critical processes or power quality. In this case study, the GTG has Priority 1. If the GTG is unavailable, any available REG can be selected as the isochronous generator, as all have the same rating.

C. *Selecting Exciter Control Mode Based on Power System Configuration*

The local generator controller supports voltage droop, constant VAR and constant power factor as exciter operating modes. For all six operating configurations listed in Table 1, the GCS ensures the exciter stays in voltage-droop mode. If the exciter switches to any other mode, the GCS automatically commands it to revert to voltage droop.

The exciters are always in voltage-droop control mode for the following reasons:

- The DER manufacturer indicates that if communication is lost between the local DER controller and the GCS, the DER maintains its last mode and set point. If operating in constant reactive power, power factor, or voltage mode, it disregards real-time system conditions—an unsafe scenario that may lead to blackouts in critical infrastructure.
- In voltage-droop mode, the GCS can adjust the no-load voltage set point of the DER, enabling control of all three parameters: reactive power, power factor, and terminal voltage. If communication fails, the DER continues adjusting based on its voltage-droop characteristics, maintaining stability.

Thus, voltage-droop mode is the preferred exciter mode in both in grid-connected or islanded operations.

D. *Selecting Autosynchronisation Breakers*

The facility's DERs came with their own unit synchronisation system, enabling them to connect to the power grid. The A25A system manages island synchronisation, with multiple autosynchronisation breakers selected in consultation with plant operators. Figure 1 illustrates the selected autosynchronisation points. This implementation provides the following benefits:

- Ensures safety by allowing medium-voltage switching to be performed remotely from the human-machine interface (HMI), providing full visibility of the facility.
- Provides flexibility for operations teams to perform switching without additional changeovers.
- Enhances reliability and availability by providing multiple options to connect either utility to downstream process loads.
- Supports island synchronisation in various power system configurations.

Table 2 presents the synchronism-check parameters and their implementation values determined based onsite testing.

TABLE 2 – SYNCHRONISM-CHECK PARAMETERS AND THEIR IMPLEMENTATION VALUES

Synchronism Parameter	Value
Maximum Voltage Difference	3%
Minimum Slip Frequency	–0.16 Hz
Maximum Slip Frequency	0.16 Hz
Maximum Angle	5 degrees
Target Close Angle	5 degrees
Synchronism Phase	Phase A
Breaker Close Time (Mechanical)	35 milliseconds

VI. TESTING SCENARIO

The facility's power system consists of two independent islands: Island 1 is connected to Utility 1, while Island 2 is connected to a GTG and a REG running in parallel. In this test scenario, the autosynchronisation feature connects the running bus (utility) and incoming bus (generator). Figure 7a and Figure 7b show real-time data captured during the test.

A. *Pre Autosynchronisation Observations*

For this test the Utility 2 breaker is open. In isochronous mode, the GTG operates at 1.28 MW, controlling the island's frequency. In FD mode, the REG operates at 0.94 MW, sharing the island's load based on the equal percentage active load-sharing algorithm.

The running bus frequency is ~60.02 Hz, while the incoming bus frequency is ~59.99 Hz (see Callout A on Figure 7a). The running bus voltage is 13.6 kV, and the incoming bus voltage is 13.1 kV (see Callout B on Figure 7a). Although the frequency difference meets the synchronism-check slip criteria, the voltage difference exceeds the 3 percent criteria, requiring PMCS correction to meet synchronism conditions.

B. *Post Autosynchronisation Observations*

Immediately after the autosynchronisation command is issued, the PMCS changes the GTG governor control mode to FD mode (see Callout C on Figure 7b), while the exciter control mode remains in voltage droop.

The GTG and REG exciters are dispatched to raise the incoming bus voltage by issuing reactive power raise pulses to the generators to increase the no-load terminal voltage of the generators without changing the reactive power output itself. Callout D on Figure 7a shows the gradual increase in incoming bus terminal voltage to meet the voltage difference requirement, while Callout E on Figure 7b illustrates the Mvar pulses issued by the PMCS.

With the slip and voltage difference within acceptable bands, the autosynchronisation relay monitors the voltage phase angle. Using slip-compensated advanced angle closing logic that is based on the slip rate and the breaker closing mechanism delay setting, the relay closes the breaker at an advanced angle to ensure the closure occurs at zero degrees.

Following the breaker closure command, the microgrid connects with the utility. It can be observed that there is a slight disturbance that occurs as the GTG real power output dips (see Callout F in Figure 7a). The GTG and REG governors are dispatched to maintain the incoming bus real power. Callout G on Figure 7b illustrates the MW raise pulses that are issued by the PMCS.

After the breaker closure, the running and incoming bus frequencies synchronise, forming one island (see Callout H on Figure 7a). The PMCS then dispatches the generator's governors to increase power generation for export via Utility 2, in response to a 0.5 MW user-entered set point request on the PMCS (see Callout I on Figure 7a). Callout J on Figure 7a show the facility's gradual power export via Utility 2 and Callout K on Figure 7b the frequent MW pulses issued by the PMCS.

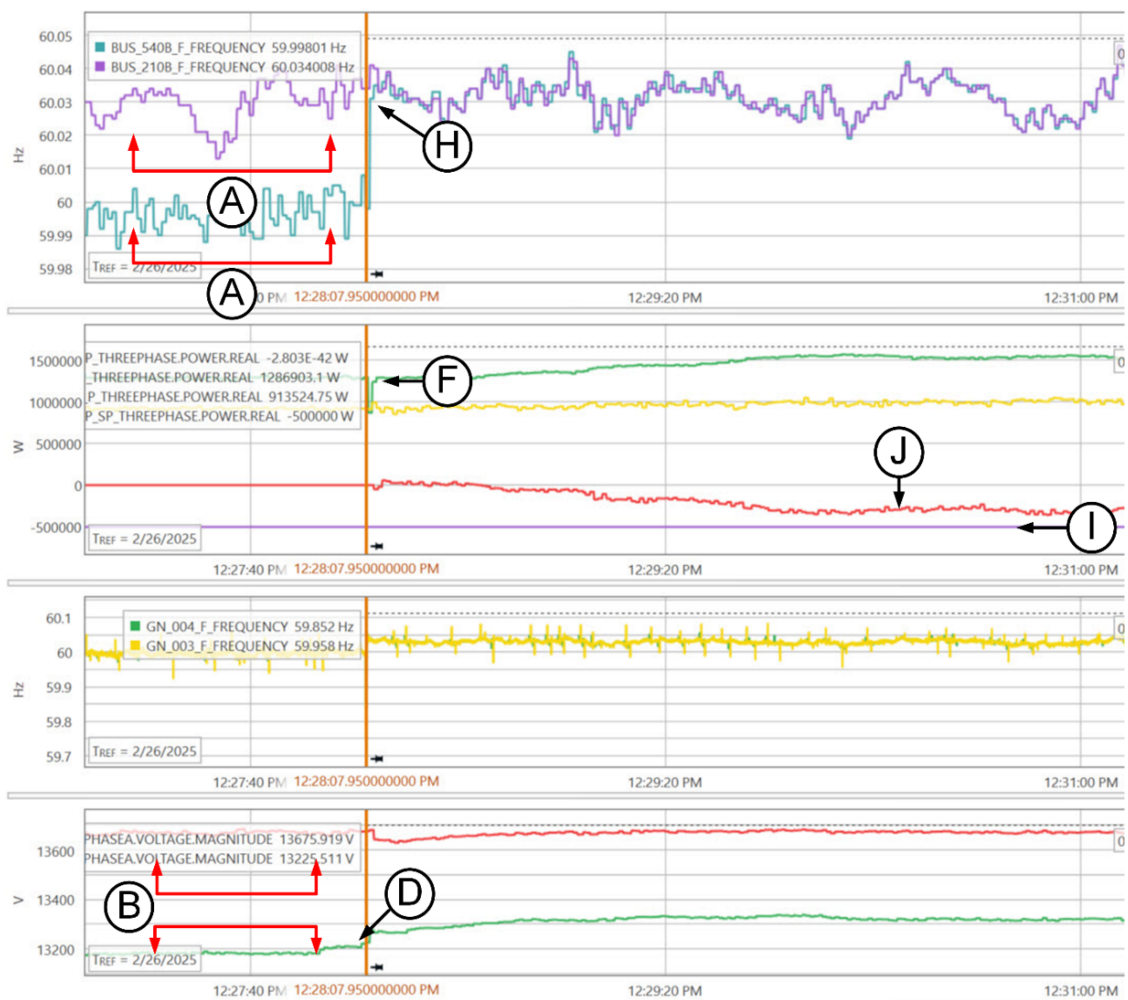

Figure 7a – Plot for Pulse Control and Analogues (P, F, and V)

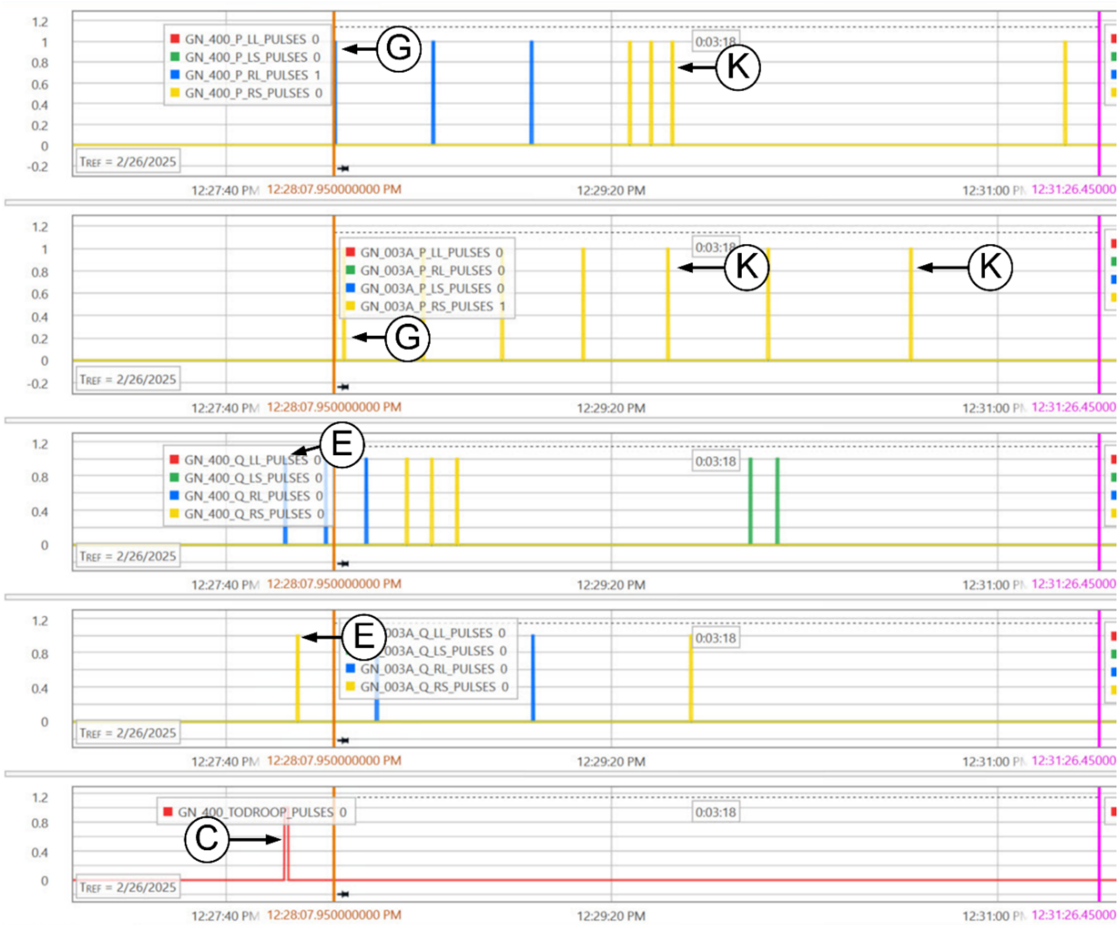

Figure 7b – Plot for Pulse Control and Analogues (P, F, and V)

VII. Conclusion

A wastewater treatment facility is critical infrastructure that directly impacts the public health and requires reliable, uninterrupted operation. Stable power systems are essential, as disturbances can cause blackouts that interrupt processes like wastewater discharge and pose health risks.

This paper discusses two main GCS functions. First, it dispatches onsite DERs to share active and reactive power when connected to the utility. When islanded, one DER switches to isochronous mode based on operator priority, while others follow to maintain stable frequency and voltage. Second, the autosynchronisation function allows operators to reconnect the system to the utility via multiple points with a single touch on the HMI, eliminating manual switching and improving reliability.

Throughout the project lifecycle, the authors addressed the following:

- All DERs were set to voltage-droop mode to maintain stable terminal voltage during communication losses between the PMCS and the DER control system.
- Upper regulation limits for DERs were set based on user values, machine capacity, and prime mover limits to ensure compliance.
- Due to limited hardwired points, the plant distributed control system provided data on the DER stages (e.g., startup or warmup), optimising dispatch to prevent overloading.

During commissioning, testing showed the frequency response of the GTG was more stable compared to the REG, leading to its selection as the priority DER for isochronous mode during islanding to maintain system stability.

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