Droop by Relay: Retrofitting Isochronous Gensets for Stable Parallel Operation

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***Abstract*—Gensets commonly found on existing sites operate in an isochronous mode and cannot parallel to utilities or other constant frequency sources without causing power and/or frequency stability problems. Converting or upgrading these existing gensets can range from challenging to impossible, often requiring vendor support to retrofit genset control, engine control unit (ECU) programming, proprietary load share lines, or other methods. This paper explains how a multifunction programmable generator protective relay (MGR) was used to convert an isochronous genset to a droop genset that can universally parallel to a utility or a microgrid.**

Droop-by-relay (DBR) technology enables customers to parallel isochronous gensets for islanded or utility grid connection. This is accomplished using relay metering, analog math, and analog output capabilities of a relay to bias the genset speed reference, creating a droop characteristic layered over the existing controller.

The authors validated DBR on a 60 kW diesel genset equipped with an analog governor and an automatic voltage regulator (AVR). Results and conclusions are shared.

I. Introduction

This paper describes how a genset protective relay is configured and tested to convert an isochronous genset to droop control. The authors provide background on isochronous controls, several variants of droop control, and a calculation of droop. They also provide droop-by-relay (DBR) control logic and explain performance criteria and test results.

II. Background

Electrical power systems are electromagnetically locked together at the same frequency. With all systems in a steady state, the measurement of frequency is the same at all locations. Temporary and localized deviations in frequency occur as angles change for changing power flow conditions because angle changes occur based upon system impedance and power flow [1].

Problems such as oscillation or frequency and power divergence occur when multiple power generation sources (i.e., generators, inverters, and/or the utility) are independently trying to define the frequency of the system in isochronous control [2].

Droop control intentionally reduces engine speed reference as real power output increases. This creates a predictable slope between frequency and power so multiple generating sources can share load without each controller independently forcing the system to the same fixed frequency. Droop allows generating assets of different manufacturers, generations, sizes, and types to parallel without proprietary load share communication or control methods. It also allows all generation systems to be independently dispatched. Droop solves many challenges with paralleling generators from different manufacturers, however, other challenges such as pole pitch harmonics should also be considered [3].

Traditional methods for converting an existing isochronous genset to modes that can support parallel operation include: 1) reprogramming the genset controller (GC), 2) replacing or augmenting the GC via a third-party controller, or 3) reprogramming the engine control unit (ECU).

This paper focuses on power/frequency droop and does not address reactive power/voltage droop controls. Though not described in this paper, DBR methodology can be used in a similar way to achieve a volt/VAR droop or virtual impedance compensated system.

A. Genset Control Systems

A genset comprises an engine, generator, exciter (not shown), ECU, automatic voltage regulator (AVR), and GC. A simplified depiction is shown in Fig. 1 [4].

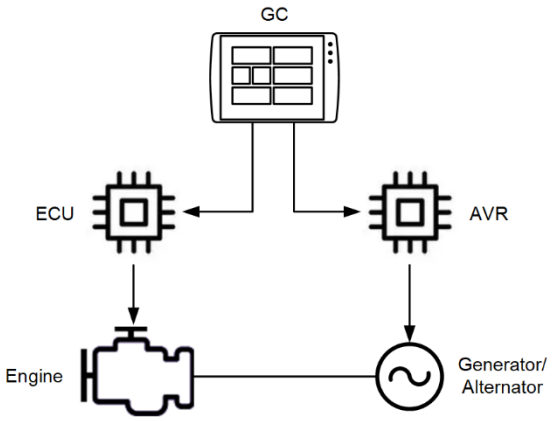


Fig. 1. Conventional reciprocating genset systems

The engine provides the mechanical power required to drive the generator. It converts fuel energy into rotational torque on the generator shaft.

An ECU or governor protects the engine from damage and provides engine speed regulation, fuel/air mixture control, fuel injection, spark control (gas engines only), and more. The speed governor (regulator) is part of the ECU function. The ECU monitors sensors on the engine and generates SAE J1939 fault codes for diagnostics [5]. The ECU also controls any government-regulated emissions and after-treatment systems. An ECU does not measure any aspect of the electrical power system.

The generator converts the shaft torque and speed supplied by the engine into electrical energy in the form of alternating current (ac).

The GC serves as the user interface for the genset, coordinating the operation of both the ECU and AVR. It issues dispatch commands such as start/stop signals and set point adjustments while also aggregating alarms and fault conditions received from the ECU and AVR. In addition to system communication and monitoring, the controller can provide protection functions, manage circuit breaker operations, and facilitate load sharing between multiple gensets.

The AVR controls the generator excitation system by outputting a direct current (dc). The brushless excitation system converts this dc to rotor current and subsequently air-gap flux. The AVR regulates terminal voltage, reactive power (VAR), and power factor to ensure the generator operates within specified limits. Some AVRs are embedded into the GC.

B. Isochronous Control

Isochronous control keeps engine rpm constant at all levels of electrical power production as shown in Fig. 2. When the load on the genset increases and the frequency begins to drop, the isochronous controller responds by increasing the throttle output. This raises the engine speed and restores the system frequency to its set point.

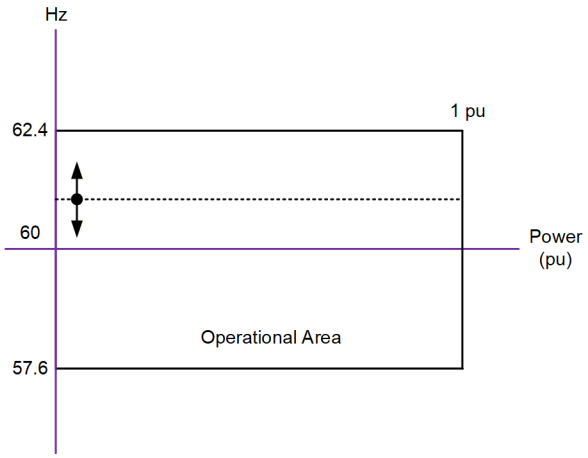


Fig. 2. One islanded isochronous genset

The dotted line of Fig. 2 indicates the rpm reference of an isochronous controller is dispatchable. The steady-state speed of an isochronous controller always returns to the dispatch set point indicated by the dotted line regardless of power output. Engines paralleling gensets to microgrids at off-nominal frequencies require the engine to be dispatched. For the genset depicted in Fig. 2, the dispatchable speed varies from 57.6–62.4 Hz.

C. Droop Controls

Droop controls will relax engine speed or power output of the genset depending on the relative stiffness of the system frequency. If the system frequency is not stiff, the engine speed will decrease as loading increases. If the system frequency is stiff, the power output of the genset will increase as the frequency decreases according to the droop curve. Droop controls are dispatched by either a frequency or a power reference; only one dispatch signal is required. The Y-axis intersection of the dotted line shown in Fig. 3 is the rpm reference of a droop controller. In this example, the frequency reference is 61 Hz, which is 1830 rpm for a 4-pole direct-connected engine and is equivalently 42 percent dispatch. The X-axis intersection of the dotted line shown in Fig. 3 is the power reference of a droop controller.

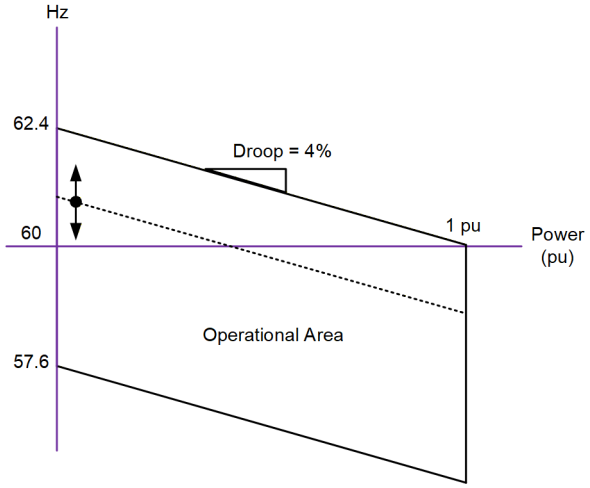


Fig. 3. One grid-connected droop genset

Fig. 4 shows the condition where an islanded droop genset is operating against a fixed load and system frequency is not stiff. To determine the speed/frequency of the islanded grid, form a vertical dashed line at the power output and find the intersection of this vertical line and the dotted lines. The intersection shows the steady-state speed of the engine and the power system frequency. Increasing the dispatch command (frequency or power set point) to the genset will not have any effect on the power output of the genset in this configuration, and only the frequency of the grid will change.

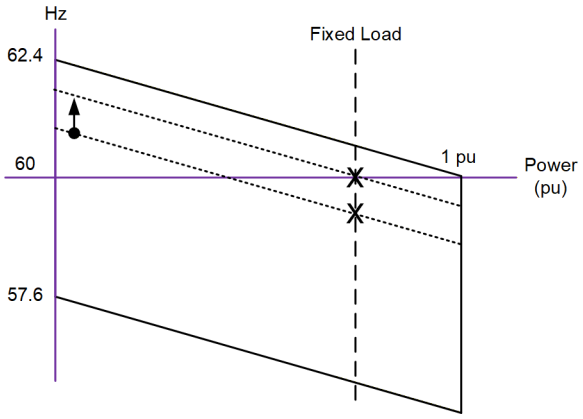


Fig. 4. One islanded droop genset

Fig. 5 shows the condition where a droop genset is operating against a stiff utility or isochronous source. In both dispatch set points, the frequency is held constant at 60 Hz. In this condition, the genset must operate at the intersection of the dotted dispatch line and a nominal 60 Hz or system frequency as always. In this configuration, the droop controller will act as a kilowatt dispatch signal whether the power or frequency reference signal is changed.

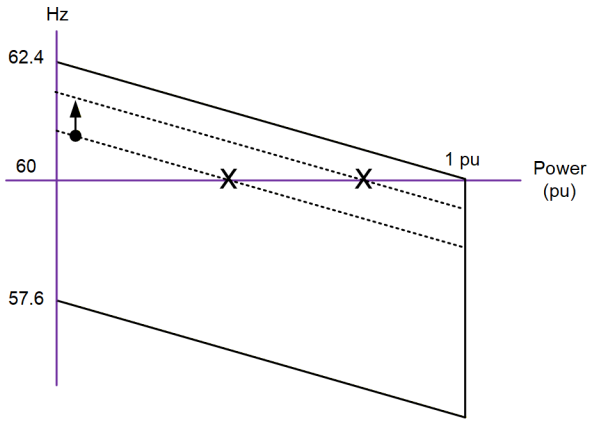


Fig. 5. One grid-connected droop genset

Fig. 6 shows the condition of two droop gensets paralleled on the same island with different dispatch set points. Both have the same droop percentage setting (slope). One genset is dispatched at 60 Hz reference (0 percent dispatch Hz/power), the other is dispatched at 61.2 Hz reference (50 percent dispatch Hz/power). The system frequency is 59.4 Hz and the respective power outputs of the gensets are 25 percent and 75 percent power output.

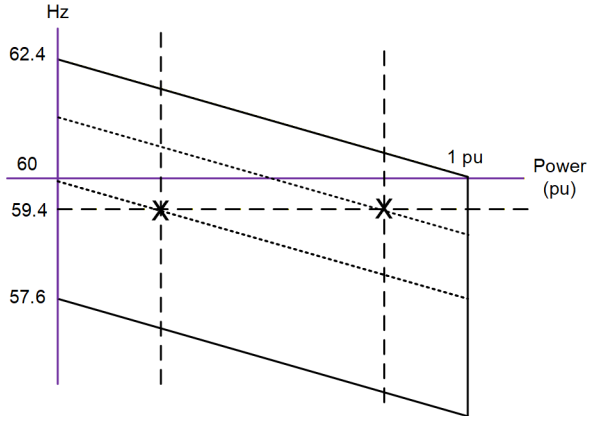


Fig. 6. Two islanded droop gensets

Fig. 7 shows the condition of two droop gensets paralleled on the same island with the same dispatch set points (60 Hz and 0 percent power) and with different droop percent settings. The system frequency is 58.8 Hz and the respective power outputs of the gensets are 50 percent and 100 percent power output.

Fig. 3–Fig. 6 show that droop dispatch is not exclusively frequency or power dispatch. It can appear as one or the other or a combination depending on the conditions of the system, i.e., islanded, paralleled with isochronous source, paralleled with drooped source. This demonstrates why a droop genset cannot be tested exclusively with dispatch set points and must be tested against a load bank and dispatch set points.

Fig. 8 illustrates how to comprehensively test a droop genset. Collecting values at all points indicated by "X" will confirm dispatch control at different loading conditions and proper frequency droop based on varied loading conditions. Further droop calculation will confirm effective droop curves. Load testing at negative dispatch levels can reveal clipping conditions in controls, prevent nuisance underfrequency protection trips, and demonstrate genset performance during low-frequency microgrid operations. It is commonly required to dispatch a generator below 60 Hz when trying to synchronize a generator to an overloaded microgrid.

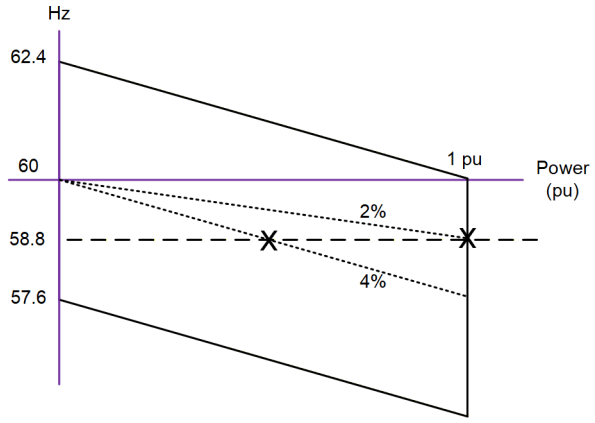


Fig. 7. Two islanded droop gensets with different droop

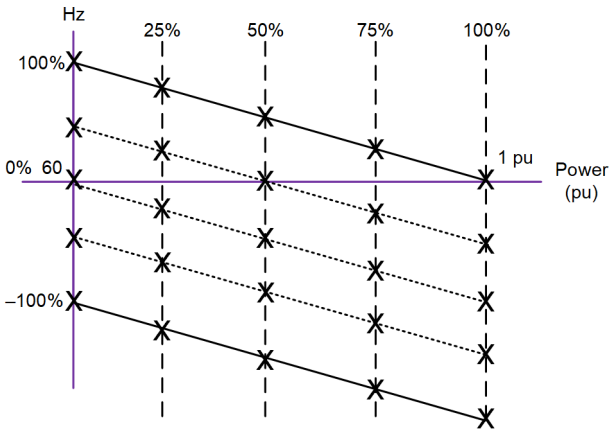


Fig. 8. Comprehensive testing of droop genset

D. Calculating Droop

Equation (1) defines the power and frequency relationship in terms of droop *R* in percent. In practice, engine droop values range from 2 to 8 percent, with 4 percent being common. *R* is the per unit or percent slope of the relationship between power and frequency.

$$R\% = \frac{\Delta f_{PU}}{\Delta P_{PU}}(100) = \frac{\frac{\Delta f}{f_{BASE}}}{\frac{\Delta P}{P_{BASE}}}(100) \quad (1)$$

where:

Δf_{PU} is the frequency change

ΔP_{PU} is the real power change

f_{BASE} is the base frequency (Hz)

P_{BASE} is the base engine rating (kW).

Calculating the first genset droop of Fig. 7:

$$R\% = \frac{\frac{\Delta f}{f_{BASE}}}{\frac{\Delta P}{P_{BASE}}}(100) = \frac{\frac{1.2}{60}}{1.0}(100) = 2\%$$

Calculating the second genset droop of Fig. 7:

$$R\% = \frac{\frac{1.2}{60}}{0.5}(100) = 4\%$$

E. Mechanical Droop Control

Fig. 9 depicts mechanical droop type control, commonly referred to as the watt-flyball governor [1]. The centrifugal force of rotating flyballs compresses a spring, meaning the shaft speed decreases as load increases. The stiffness of the spring and the linkages of the lever arm connecting the flyballs determine the effective proportional gain $1/R$. Instead, fuel output (proportional to power) increases as frequency error increases. The frequency control error builds up because there is no integral action—mechanical governors are proportional-only controllers.

Flyball governors still exist today in mechanical fuel pumps for large engines, in small generators, and on older generator sets. Notice there is no power measurement in the mechanical droop control, and thus the proportional gain is the inverse of the droop. For example, a 5 percent droop corresponds to $1/R = 1/0.05 = 20$. This coupling between gain and droop is the major shortcoming of the mechanical governor design and means that to change droop, the gain must be changed. This coupling between gain and droop means tuning is severely restricted. For example, if you wish to make the engine more responsive the gain must go up, and thus the system droop goes down. The droop-gain dynamic commonly creates situations where stability margins and droop requirements cannot be met simultaneously.

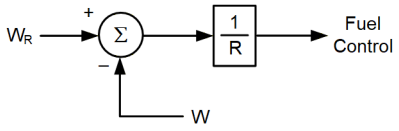


Fig. 9. Mechanical droop control

F. Fuel Valve Reference Droop Control

Fig. 10 depicts fuel valve reference droop (FVRD) type control. Digital ECU and analog fuel valve governors commonly have this form of droop control. This is another form of droop used when the controller does not have measurements of electrical power. In lieu of measured electric power, ECU uses the fuel rate set point as the measurand. FVRD has two primary advantages: 1) the droop R is decoupled from the proportional integral derivative (PID) speed regulator gains, and 2) the phase and gain margins are much larger than the forms of droop controllers that use measured power because there is no power measurement lag. The disadvantage of FVRD is the effective droop line will not be a straight line due to the non-linear relationship between fuel and power at different load levels. FVRD type droop controllers are known for stability in power systems.

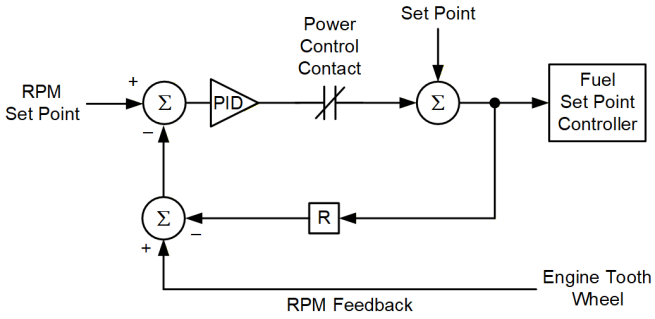


Fig. 10. FVRD control

G. Power Metered Droop Control

Fig. 11 depicts metered droop type control. Advanced GCs have this form of droop control as they have measurements of electrical voltage and current. We explore this formulation of controls in the paper. The relay is the metered droop controller for an inner isochronous-controlled genset. The advantages include: 1) ECU tuning will be factory isochronous speed regulation and will match Environmental Protection Agency compliance records, 2) integration cost will be minimal, and 3) the droop R is decoupled from the PID speed regulator gains. The disadvantage is that the measurement of power induces a lag in the controls, which erodes phase and gain margins. Often, a power-metered droop system can exhibit undesired sub-synchronous control oscillations if improperly designed, configured, or installed. These problems generally come from lag in metering and filters.

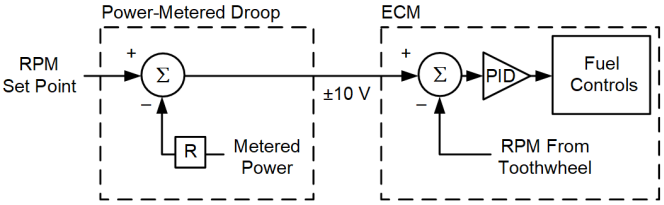


Fig. 11. Power-metered droop control

H. Genset Configurations

The genset controlled by DBR in this paper is a tactical quiet generator (TQG). The TQG is a 60 kW, 75 kVA mechanically fuel-injected diesel reciprocating genset wired for a 208 V three-phase system. This TQG has been retrofitted with a multifunction programmable generator protective relay (MGR) that operates as a GC. The MGR controls an analog isochronous governor and an analog AVR via 0–5 Vdc output signals. The mechanical fuel pump has an analog actuator that is proportionally controlled by the analog governor. The MGR controls field flash as there is not permanent magnet generator. The MGR also controls engine start/stop, cooldown, automatic breaker synchronization, and local/remote dispatch, and it monitors fuel level, battery voltage, and cooling water temperature.

An isochronous electronically fuel-injected diesel 100 kW genset was used for paralleling tests to emulate a grid connection. A third fuel valve reference droop 30 kW

mechanically injected diesel genset was used to emulate microgrid operation of paralleled droop gensets.

III. DBR Controls

Fig. 12 shows the DBR controller implemented in the MGR settings. The controller measures the power output of the generator and converts this into percentage of genset rating. If the sample and hold (S&H) switch is closed, the percent measured power is subtracted from the set point. The difference is then sent to an analog output. The analog output contains linear zero and slope calculations for the creation of a low-level voltage signal sent to the speed governor. No additional filters beyond those in the relay firmware were used. The objective is to have the quickest response possible and have deadband (i.e., hysteresis) act as our stabilizing function. The MGR analog output updates every 100 ms.

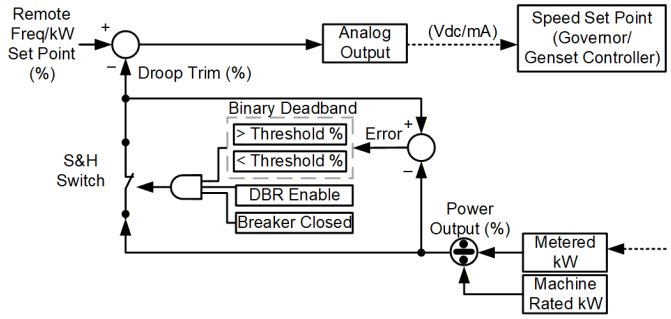


Fig. 12. DBR control loop

The S&H switch is held open, and the droop trim percentage is zeroed if the DBR control is disabled. The S&H switch is closed if the droop falls outside a deadband. The deadband is used to provide transient stability and prevent generator sub-synchronous oscillations. If DBR is enabled and the S&H switch is open (i.e., the control is within deadband), then the droop trim is held at last sampled value.

The deadband operates by comparing the previously issued droop trim to the present power metering percentage. If the error exceeds the thresholds of the deadband, the present power metering percentage is adopted as the new droop trim. Initial deadband values of ±5 percent resulting in ±0.12 Hz of deadband around a 4 percent droop curve. Deadband values can be adjusted to improve accuracy and/or stability.

In summary, the DBR controller controls power secondarily by adjusting the generator speed reference while operating in Isochronous mode. The controller continuously modifies the isochronous speed reference until the desired generator power output is achieved. Once equilibrium is reached, the speed reference is maintained at the corresponding value required to sustain the target power output under the system conditions, or genset speed is decreased until it matches power draw percentage and drooped performance. Fig. 13 demonstrates how the DBR adjusts the isochronous speed reference until it matches the droop characteristic.

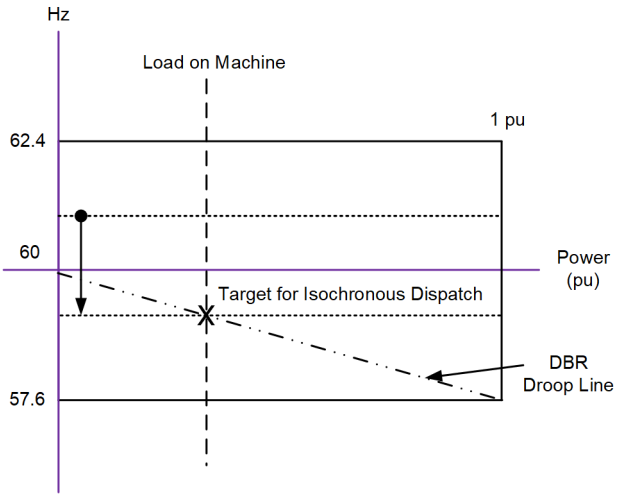


Fig. 13. DBR control matching droop characteristic based on genset loading

Table I shows the scaling configured in the analog speed isochronous speed regulator.

TABLE I
ANALOG DISPATCH TO SPEED REFERENCE

Voltage Output (Vdc)	Frequency (Hz)	Percentage Assigned
1.113	57.6	–100
1.81	60.0	0
2.50	62.4	100

IV. Baseline Validation

The authors performed the following tests to validate all genset controls were operating as expected prior to testing the MGR droop control:

- Tested the TQG to confirm it acted as an isochronous source with the DBR disabled.
- Tested a 100 kW diesel isochronous rental genset to confirm it acted as an isochronous source. The purpose was to replicate a grid connection.
- Paralleled two isochronous gensets to confirm system instability.

A. TQG Isochronous Validation With DBR Disabled

Fig. 14 demonstrates the baseline performance of the isochronous controller on the TQG. For these tests, DBR was disabled from the MGR interface. The TQG operates in this condition at the governor level for all tests in this paper. Any droop performance noted on the TQG thereby comes from the DBR controls.

In these tests, the TQG was connected to a resistive/inductive load bank with power factor at 0.8. The load was increased at 10 kW increments until 50 kW was reached. Then all load was removed in one step, a single-step 20 kW load was added and removed, and a single-step 40 kW load was added and removed.

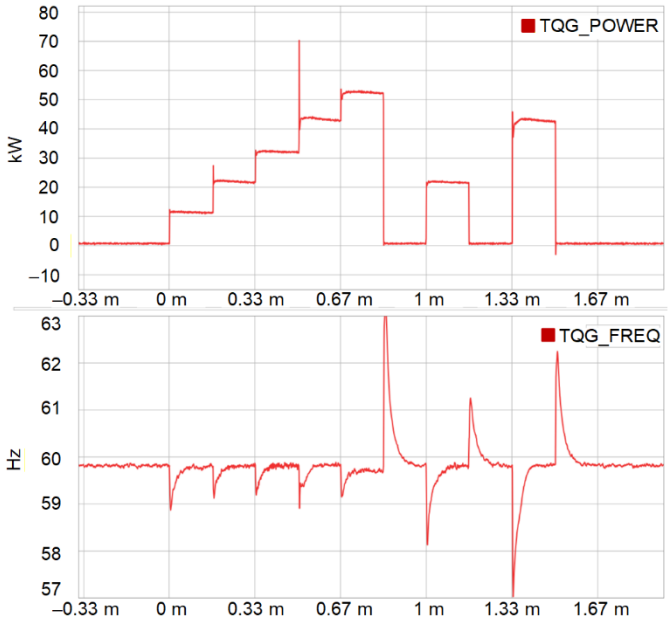


Fig. 14. TQG isochronous response

These tests indicate an overdamped first-order system with a dominant time constant of ~1.5 seconds. The analog governor does not return to 60 Hz. Steady-state frequency is ~59.8 Hz at low loads and 59.7 Hz for higher loads, illustrating the isochronous operation. These errors from 60 Hz are common in analog isochronous governors due to analog circuitry drift and calibration errors.

B. 100 kW Isochronous Validation

Fig. 15 demonstrates the baseline performance of the isochronous 100 kW genset with loading adjusted to match the genset capacity. This genset has a digital controller and, thus, the frequency returns to 60.0 Hz. This control is overdamped with a single pole at approximately 2 seconds.

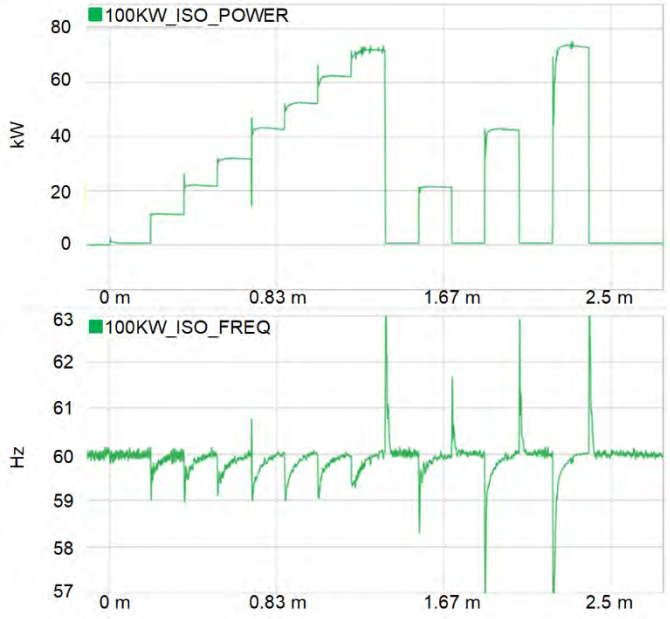


Fig. 15. 100 kW isochronous response

C. Instability With Two Isochronous Gensets

Fig. 16 shows the TQG in Isochronous mode paralleled to the isochronous 100 kW genset. Because of the analog governor steady-state speed error, the two gensets diverged in power immediately upon paralleling. Load testing of 5 kW and then 15 kW was added, then all load was removed.

The results indicate that the TQG was trying to speed up the 100 kW genset. The opposite result was expected, as the prior tests showed the TQG isochronous operation at a frequency below the 100 kW isochronous genset. The reason for this is that the A25A synchronization procedure raised the governor steady-state set point to slightly greater than 60 Hz before automatically closing the TQG circuit breaker under an acceptable angular difference. In other words, the synchronizer was configured such that the TQG was above grid frequency before closing to avoid torque reversal [6]. This was observed just before the 0-minute mark. The very small slip difference caused the TQG to motor (i.e., reverse power) the 100 kW genset.

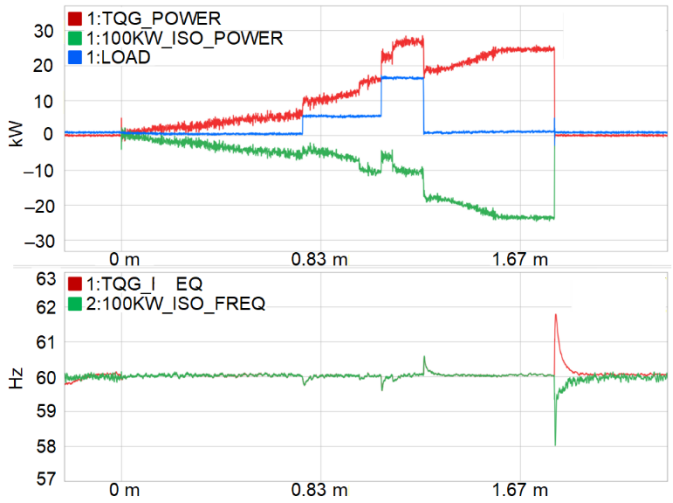


Fig. 16. TQG isochronous and paralleled 100 kW isochronous power divergence

In this case, the 100 kW genset reached a maximum reverse power of 23 kW, which is the full amount of braking load the isochronous genset can provide to the system once its throttle position reaches 0 percent.

The reverse power of 23 kW encompasses the aggregate internal energy consumption required to sustain isochronous genset operation under no fuel injection. Contributing factors include mechanical friction, bearing losses, compression losses, auxiliary systems such as coolant pumps, fuel systems, and turbochargers, cooling systems such as radiator and generator fans, alternator losses, and inherent electrical resistance within the generator.

In this mode, the isochronous genset acted as a compressor load attempting to slow system frequency. The power difference stopped escalating once the 23 kW limit was reached and the 100 kW genset could no longer slow system frequency, allowing the TQG genset to reach its slightly higher targeted frequency. This higher frequency is easiest to observe at 1.67 m.

V. DBR Testing

The authors performed the following tests to confirm the DBR control met all requirements for Utility Grid, Microgrid, and Islanded mode operation:

- Island loading to confirm that frequency fell with increased loading.
- Paralleling to a droop genset to confirm the DBR control did not diverge or oscillate in a microgrid situation.
- Paralleling to an isochronous genset to approximate operation against a compliant grid connection.
- Driving the isochronous genset into reverse power to confirm the DBR deadband controls suppressed oscillations.

A. *DBR Islanded Load Tests*

Fig. 17 shows the TQG with the MGR DBR enabled against a load bank. The plots from top to bottom are kW, Hz, and percent signals. The percent signals are DBR (internal) values of DBR trim sent as a 0–5 Vdc analog set point to the TQG isochronous governor.

The external set point TQG_FREQ_SETPOINT is kept at 0 percent, or 60 Hz. The DBR_ERROR_SIGNAL remains within approximately ±5 percent during steady-state operation and exhibits brief excursions beyond the deadband during large load transitions, after which it quickly returns toward the deadband region. The percent trim signal descends to ensure the TQG slows down for increased load.

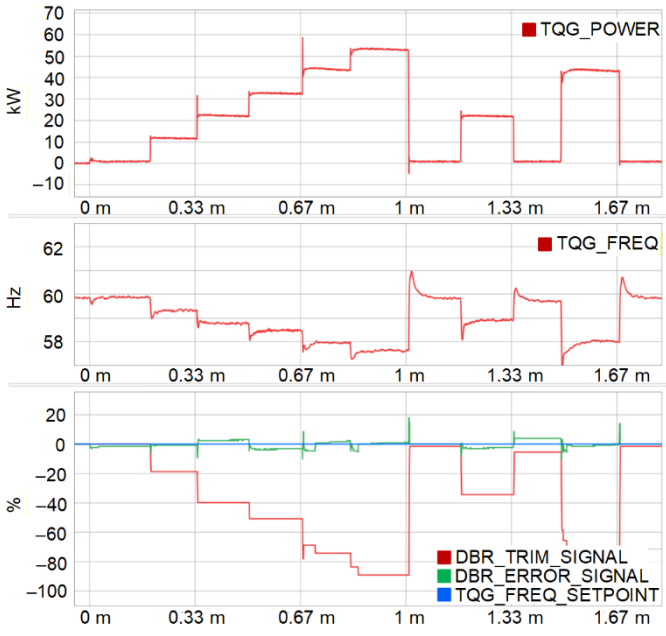


Fig. 17. TQG DBR islanded response

Fig. 18 is a plot of several more Islanded mode tests with varying dispatch set points. Varying set point tests are required to confirm that the droop controller is fully dispatchable within the desired frequency operational region of Fig. 2. This test identifies any clipping, non-linearities, or other mistaken configurations.

Fig. 18 shows how the effective droop percentage changes based on how much dispatch is sent to the genset. This variance occurs because the governor does not respond linearly to isochronous speed analog references and the DBR as implemented does not actively correct for these non-linearities. Droops were measured to vary between 3.8 and 5.7 percent. This variance is normal and these are acceptable results when using an analog isochronous speed regulator.

Fig. 19 shows the non-linear speed governor as a function of dispatch set point percentage for both a loaded and unloaded condition. This non-linearity is another cause of the effective droop percentage varying with dispatch set point. These are normal challenges with analog governors. In this case, a rotary servo is driving a linear fuel rack utilizing small sine angle approximation. A digital ECU would not have these effects, and therefore the DBR driving a digital ECU will provide more consistent droop results.

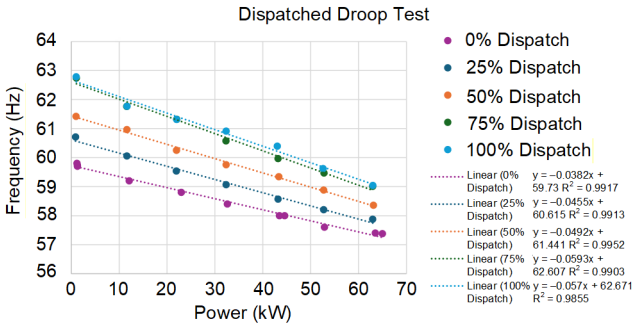


Fig. 18. TQG DBR islanded tests with varying set points

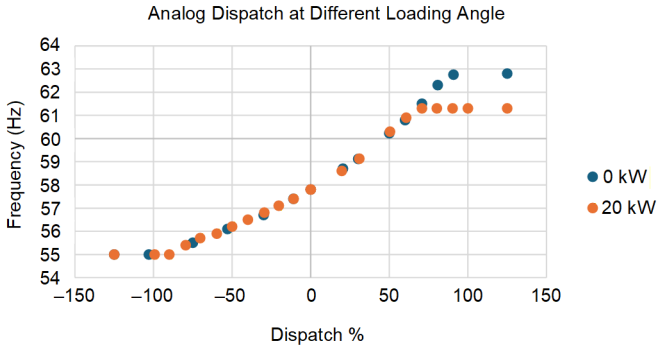


Fig. 19. TQG governor non-linearity and clipping

B. *DBR Paralleling to Droop Generator*

Fig. 20 shows the TQG DBR paralleled to a 30 kW genset operating in FVRD. Both genset dispatch set points are held constant, which is the natural response of the droop sharing between these two gensets.

The data show that the two gensets are not load sharing in exactly equal proportion, however, they are sharing adequately with stable power and frequency. To share perfectly, the results would show the 60 kW genset picking up twice the load of the 30 kW genset. Notice they did not share 2:1 because these imperfections are due to droop values, deadbands, and non-linearities in both the isochronous TQG speed governor and the 30 kW FVRD controller. These small errors are commonly corrected with a more complex DBR technique in the MGR or a microgrid dispatch controller.

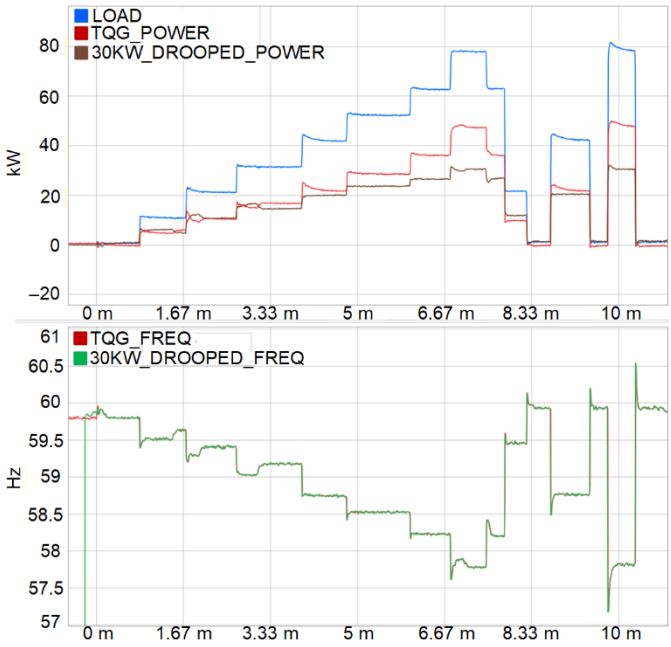


Fig. 20. TQG DBR and 30 kW droop genset paralleled

C. *DBR Paralleling to Isochronous Genset*

Fig. 21 validates that a DBR genset allows stable operation against a stiff frequency source such as an isochronous genset or utility. The initial test sequence consists of incremental load steps followed by load acceptances and rejections of 20, 40, and 80 kW. During these steps, the DBR dispatch is held at 0 percent. Both the TQG and isochronous gensets transiently respond by sharing the applied load. As the isochronous genset recovers the frequency back to 60 Hz, the TQG power output is returned to zero by the DBR. This behavior is consistent with classical droop control operation, wherein droop gensets help the grid transiently but settle back to pre-disturbance outputs. Notice during the 40 kW and 80 kW load rejections the TQG reverse powered (i.e., acted like a compressor) because the isochronous genset drove the TQG into reverse power until the speed rise was detected by the isochronous controller. This behavior is why gensets on a microgrid are best set to similar dispatch set point percentages so that no gensets are transiently forced into reverse power. This is one of many reasons why all droop-controlled microgrids are more resilient than microgrids with a combination of isochronous and droop controls.

In Fig. 21, the plot ends with an 80 kW load added for 1.5 minutes. During this time the DBR droop dispatches from the MGR user interface, causing the TQG output to rise and the isochronous genset to fall. This simulates a microgrid controller action where the TQG can be dispatched to offset local microgrid loading.

When the load was removed, the isochronous genset acted as a load (i.e., reverse powered) until droop dispatch was zeroed at the TQG. These are normal load rejection challenges of microgrids where the utility is faced with reverse power should a large load within a microgrid trip offline. To prevent this unintended operation, utility reverse power elements are commonly time coordinated with onsite microgrid control response times. Reverse power protection times are therefore coordinated with the microgrid controller tuning, thus giving the microgrid controller time to act before a point of common coupling is tripped.

Notice that, after this load trip, the isochronous genset could not keep the frequency to 60 Hz because the engine is limited to 23 kW of losses as described in Fig. 15.

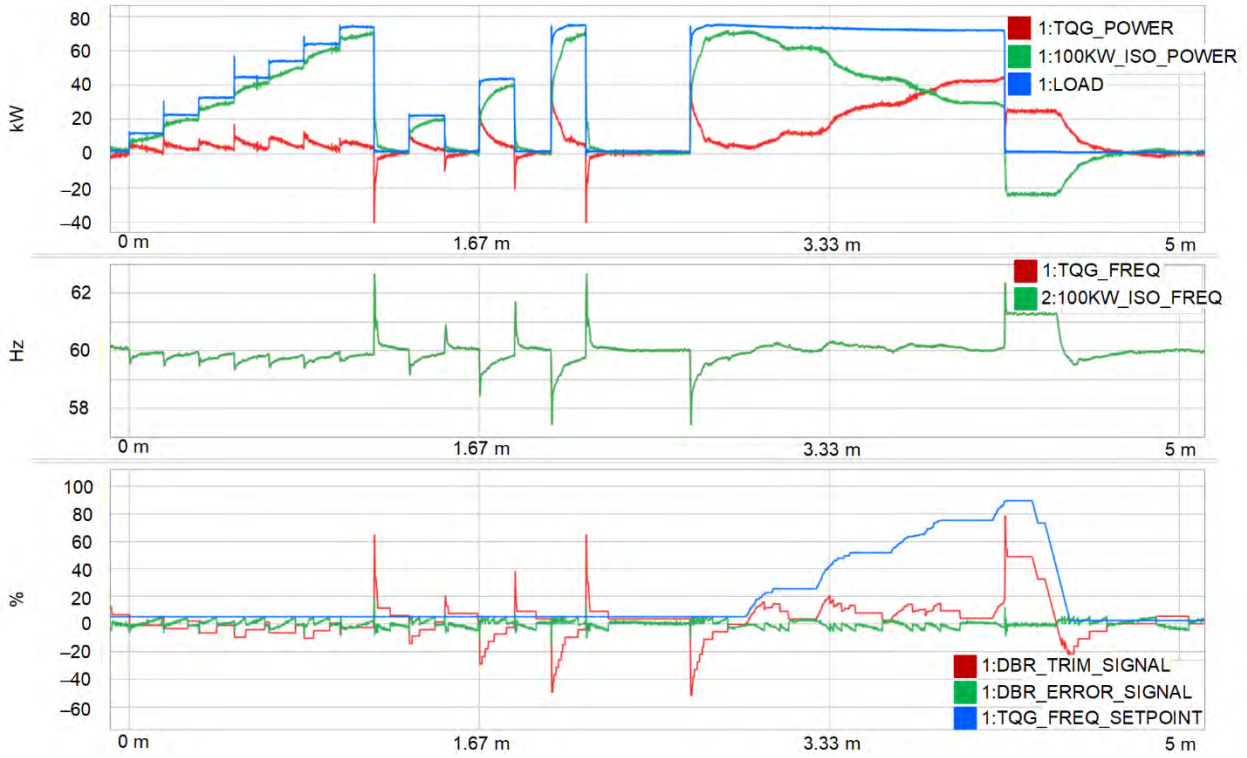


Fig. 21. TQG DBR paralleled to 100 kW isochronous with and without DBR dispatch

D. Reverse Power Testing

Fig. 16 and Fig. 21 show conditions where the isochronous genset was driven into a reverse power limit of 23 kW. Fig. 22 shows conditions where the TQG was driven into reverse power. Reverse powering was intentional for several reasons.

The reader is cautioned never to reverse power a turbine engine as it may be damaged. Losses are lower in a turbine and back compressions may cause flame-out or pressure-wave pulsations. Turbine blades may be fatigued. This is why most turbine engines are not appropriate for microgrids with periodic motoring events, large load pulsations, or large frequency deviations.

Many reciprocating engines can be motored to find losses. For the isochronous genset, the losses were ~23 kW. For the TQG, the losses were ~5 kW. When driving a reciprocating engine as a compressor, most of the compression energy is returned to the engine. The compressed air acts as a spring to return the piston, putting the energy of compression back into the engine. Other industries use reciprocating engines as brakes, with three common methods: intake braking, compression braking, and exhaust braking [7].

VI. Other Considerations

This section describes other factors that should be considered when implementing a DBR controller. The authors address application to voltage, oscillations, measurement changes, financial benefits, and failure types.

A. Volt/VAR Control

Though not shown in this paper, DBR methodology can be used in a similar way as frequency/power to achieve a volt/VAR droop or virtual impedance compensated system.

B. Oscillations

Fig. 22 shows the TQG reverse powered and oscillating with the isochronous genset. The oscillation period was roughly 16.8 seconds and did not attenuate or grow. Reciprocating engines commonly oscillate at low power or during braking (negative power). These conditions occur commonly because the motored engine is at a non-linear extent of both the controls and mechanical design.

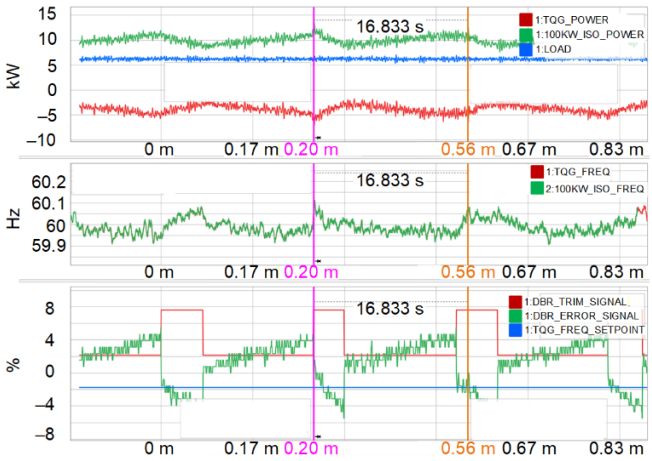


Fig. 22. TQG DBR oscillations when paralleled to 100 kW isochronous genset, no load

C. Measurement Differences

Fig. 23 shows the frequency measurement in real time compared between the TQG and isochronous genset. The actual frequencies are the same as they were paralleled. These measurement differences were observed to be similar under all loading conditions.

The differences observed are due to the C37.118 data stream coming from a protective relay for the TQG and a power quality meter for the isochronous genset. C37.118 frequency measurement methods in a relay are different than for a meter.

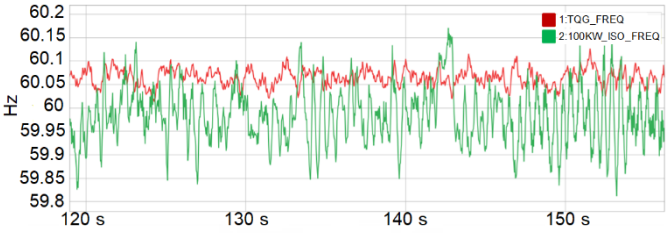


Fig. 23. Frequency measurement differences

D. Financial Considerations

Integrating DBR methods into existing gensets is an alternative to purchasing a new genset. New gensets often require new permitting (e.g., sounds, air, environmental, safety), which may delay a project. Newer diesel gensets require complex and costly Tier 4 emissions systems that require diesel exhaust fluid (commonly known as DEF), which can reduce reliability. For new engines, customers often need new training and maintenance, face costly coordination of contractors and outages, and experience lengthy manufacturing lead times.

Isochronous gensets are often unable to parallel to utilities or microgrids. As such, they represent underutilized resources. Paralleling these gensets with a DBR upgrade provides significant value that may include:

- Participation when renewable generation or energy storage systems are unavailable.
- Peak shaving, demand response, and reduced utility energy and demand charges.
- Practical automated testing without a load bank, offsetting contractor and electrical cost with required testing.
- Formation of islanded microgrids and parallel operation with other generators.
- Improved resilience, operational flexibility, load sharing, and dispatch capabilities.
- Enhanced integration of distributed energy resources and external microgrid controllers.
- Deferred capital expenditures and minimized permitting, engineering, and installation impacts.

E. Historian

C37.118 data streaming from relays and meters can be merged into a centralized time-synchronized data historian for later analysis.

F. Failure Condition

In the event of a control or MGR failure, which would also constitute a protection system failure, the genset will operate in Isochronous mode without DBR feedback. This would likely result in either overpower or reverse power conditions after a short period if the desired isochronous speed is not achieved.

G. Interface

The interface tested was a low level 0–5 Vdc signal. Pulse-based dispatch is not considered viable for DBRs because the response times of pulse-integration-based systems are too slow to meet many operational requirements. A high-speed, communication-based dispatch solution may be evaluated as a future option.

VII. Conclusion

The authors drew two conclusions from the results discussed in the paper:

- All drooped generation should undergo a similar testing regimen completed by the DBR.
- DBR methods convert an isochronous genset that cannot parallel with other gensets or the utility into one that can.

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IX. Biographies

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