AGC-4 Mk II

Genset, Mains, BTB, Group, and Plant controller

Designer's handbook

4189341275D

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1. Introduction

1.1 About the Designer's Handbook

1.1.1 General purpose

This **Designer's Handbook** provides overall information about the controller applications and functions. This document also provides the information needed to configure the application and its parameters.

See the **Installation instructions** for installation information. See the **Operator's manual** for information on how to operate the controller.

CAUTION

Incorrect configuration is dangerous

Read this document before starting to work with the controller and the equipment to be controlled. Failure to do this could result in human injury or damage to the equipment.

1.1.2 Intended users

This Designer's Handbook is mainly intended for the panel builder designer. On the basis of this document and the Installation instructions, the panel builder designer will give the electrician the information he needs to install the controller, for example, detailed electrical drawings.

1.1.3 Options

This **Designer's Handbook** describes the standard AGC-4 Mk II controller, especially the genset controller.

The controller functions can be increased by a variety of flexible hardware and software options. The **Data Sheet** includes a complete list of options. The options are described in detail in **Description of Options** documents.

Option G5 Power management describes power management using genset, mains and BTB controllers.

Option G7 Extended power management describes power management using group and plant controllers.

1.1.4 Parameter list

The Designer’s Handbook refers to parameters. For further information, see the **Parameter list**.

1.1.5 Glossary

Term	Abbreviation	Explanation
Additional Operator Panel	AOP	See **Option X Additional displays and operator panels**.
AGC-4 Mk II	AGC-4 Mk II	By default, a genset controller. With option G5, also a mains or BTB controller. With option G7, also a group or plant controller. AGC-4 Mk II is based on AGC-4, with updated hardware.
AGC 150	AGC 150	This includes AGC Genset, AGC BTB and AGC Mains controllers. They can be included in AGC-4 Mk II power management applications.
Automatic Load Controller	ALC-4	
Automatic Mains Failure	AMF	If there is a mains failure, the AGC automatically uses a genset to supply the load.

Term	Abbreviation	Explanation
Automatic Sustainable Controller	ASC 150 ASC-4	The ASC Solar and Storage/Battery can be included in AGC power management applications.
Automatic transfer switch	ATS	
Automatic voltage regulator	AVR	
Busbar	BB	
Bus tie breaker	BTB	
CANshare		Controller communication over CAN bus for equal load sharing.
Close before excitation	CBE	
Controller redundancy		See **Option T1 Critical power**.
Current transformer	CT	
Display unit	DU-2	A display unit for the AGC-4 Mk II controller. Alternatively, use a TDU.
Engine communication	EIC	See **Option H12 H13 Engine communication**.
Extended power management		Genset, BTB, solar, group and/or plant controllers work together. See **Option G7 Extended power management**.
Genset/generator	G	
Generator breaker	GB	
Governor	GOV	
Grid protections		See **Option A10 AGC-4 Mk II VDE and G99 grid protections** or **Option A20 IEEE 1547-2018 grid protection**.
Load take over	LTO	
Mains breaker	MB	
Mains power export	MPE	
Menu	[####]	A group of parameters.
M-Logic		The PLC-type tool accessible from the utility software.
Modbus		See **Option H2 and H9 Modbus communication and AGC-4 Mk II Modbus tables**.
Multi-line-2	ML-2	A DEIF platform, which includes the AGC-4 Mk II.
Nominal power	P nom	
Nominal reactive power	Q nom	
Nominal voltage	U nom	
Parameter	[####]	A configurable setting (sometimes also called *Channel* in the PC utility software).
PC utility software	USW	
PMS lite		A simplified power management system, with limited functions. PMS lite is only for genset controllers. The configuration and use of PMS lite can be simpler.
Power management system	PMS	Genset, mains, BTB, ALC, battery/storage, and/or solar controllers work together. See **Option G5, Power management**.
Profibus		See **Option H3 Serial communication Profibus DP**.
Resistance measurement input	RMI	
Single controller		The single controller operates based on its own measurements and inputs. The single controller does not use communication with other

Term	Abbreviation	Explanation
		controllers. Single controllers are used in applications without power management.
Software	SW	
Touch display unit	TDU	A range of pre-programmed touch screen displays for the AGC-4 Mk II genset controllers.
Voltage transformer	VT	

1.1.6 Software version

This document is based on AGC-4 Mk II software version 6.11.

1.2 Warnings and safety

1.2.1 Symbols for hazard statements

DANGER!

This shows dangerous situations.

If the guidelines are not followed, these situations will result in death, serious personal injury, and equipment damage or destruction.

WARNING

This shows potentially dangerous situations.

If the guidelines are not followed, these situations could result in death, serious personal injury, and equipment damage or destruction.

CAUTION

This shows low level risk situation.

If the guidelines are not followed, these situations could result in minor or moderate injury.

NOTICE

This shows an important notice

Make sure to read this information.

1.2.2 Symbols for general notes

NOTE This shows general information.

More information
This shows where you can find more information.

Example

This shows an example.

How to ...
This shows a link to a video for help and guidance.

1.2.3 Factory settings

The controller is delivered pre-programmed from the factory with a set of default settings. These settings are based on typical values and may not be correct for your system. You must therefore check all parameters before using the controller.

1.2.4 Automatic and remote-controlled starts

The power management system automatically starts gensets when more power is needed. It can be difficult for an inexperienced operator to predict which gensets will start. In addition, gensets can be started remotely (for example, by using an Ethernet connection, or a digital input). To avoid personal injury, the genset design, the layout, and maintenance procedures must take this into account.

1.2.5 Safety during installation and operation

Installing and operating the equipment may require work with dangerous currents and voltages. The installation must only be carried out by authorised personnel who understand the risks involved in working with electrical equipment.

DANGER!

Hazardous live currents and voltages

Do not touch any terminals, especially the AC measurement inputs and the relay terminals. Touching the terminals could lead to injury or death.

1.2.6 Electrostatic discharge awareness

Sufficient care must be taken to protect the terminal against static discharges during the installation. Once the unit is installed and connected, these precautions are no longer necessary.

1.3 Legal information and disclaimer

DEIF takes no responsibility for installation or operation of the generator set or switchgear. If there is any doubt about how to install or operate the engine/generator or switchgear controlled by the Multi-line 2 unit, the company responsible for the installation or the operation of the equipment must be contacted.

NOTE The Multi-line 2 unit is not to be opened by unauthorised personnel. If opened anyway, the warranty will be lost.

Disclaimer

DEIF A/S reserves the right to change any of the contents of this document without prior notice.

The English version of this document always contains the most recent and up-to-date information about the product. DEIF does not take responsibility for the accuracy of translations, and translations might not be updated at the same time as the English document. If there is a discrepancy, the English version prevails.

2. Functions

2.1 Standard functions

This chapter includes functional descriptions of standard functions as well as illustrations of the relevant application types. Flowcharts and single-line diagrams will be used in order to simplify the information.

The standard functions are listed in the following paragraphs.

2.1.1 Operation modes

- Automatic Mains Failure
- Island operation
- Fixed power/base load
- Peak shaving
- Load takeover
- Mains power export

2.1.2 Engine control

- Start/stop sequences
- Run and stop coil
- Relay outputs for governor control

2.1.3 Generator protection (ANSI)

- 2 × reverse power (32)
- 5 × overload (32)
- 6 × over-current (50/51)
- 2 × over-voltage (59)
- 3 × under-voltage (27)
- 3 × over-/under-frequency (81)
- Voltage-dependent over-current (51V)
- Current/voltage unbalance (60)
- Loss of excitation/over-excitation (40/32RV)
- Non-essential load/load shedding, three levels (I, Hz, P>, P>>)
- Multi-inputs (digital, 4 to 20 mA, 0 to 40 V DC, Pt100, Pt1000 or RMI)
- Digital inputs

2.1.4 Busbar protection (ANSI)

- 4 × over-voltage (59)
- 5 × under-voltage (27)
- 4 × over-frequency (81)
- 5 × under-frequency (81)
- Voltage unbalance (60)

2.1.5 Display DU-2

- Prepared for remote mounting
- Push-buttons for start and stop

- Push-buttons for breaker operations
- Status texts

Alternatively, you can use a TDU.

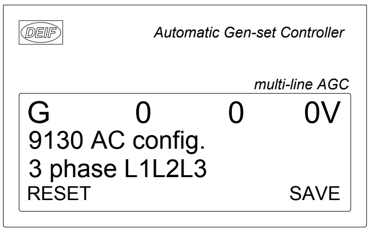
2.1.6 M-Logic

- Simple logic configuration tool
- Selectable input events
- Selectable output commands

2.2 AC configuration

The AGC is designed to measure voltages between 100 and 690 V AC. The AC wiring diagrams are shown in the **Installation Instructions**. You can select the AC configuration in menu 9130 (three-phase, single phase and split phase).

Change the settings using the display or the USW. To use the DU-2 display, press the JUMP push-button and go to menu 9130. The display looks like this:



Use the or push-button to select the AC configuration. Press the push-button until SAVE is underscored, and then press to save the new setting.

CAUTION

Incorrect configuration is dangerous

Configure the correct AC configuration. If in doubt, contact the switchboard manufacturer for information.

2.2.1 Three-phase system

When the AGC is delivered from the factory, the three-phase system is selected. When this configuration is used, all three phases must be connected to the AGC.

The table below contains the parameters to make the system ready for three-phase measuring.

The example below is with 230/400 V AC, which can be connected directly to the AGC's terminals without the use of a voltage transformer. If a voltage transformer is necessary, the nominal values of the transformer should be used instead.

Setting	Adjustment	Description	Adjust to value
6004	G nom. voltage	Phase-phase voltage of the generator	400 V AC
6041	G transformer	Primary voltage of the G voltage transformer (if installed)	400 V AC
6042	G transformer	Secondary voltage of the G voltage transformer (if installed)	400 V AC
6051	BB transformer set 1	Primary voltage of the BB voltage transformer (if installed)	400 V AC

Setting	Adjustment	Description	Adjust to value
6052	BB transformer set 1	Secondary voltage of the BB voltage transformer (if installed)	400 V AC
6053	BB nom. voltage set 1	Phase-phase voltage of the busbar	400 V AC

NOTE The AGC has two sets of BB transformer settings, which can be enabled individually in this measurement system.

2.2.2 Split phase system

This is a special application where two phases and neutral are connected to the AGC. The AGC shows phases L1 and L3 in the display. The phase angle between L1 and L3 is 180 degrees. Split phase is possible between L1-L2 or L1-L3.

The table below contains the parameters to make the system ready for split phase measuring.

The example below is with 240/120 V AC, which can be connected directly to the AGC's terminals without the use of a voltage transformer. If a voltage transformer is necessary, the nominal values of the transformer should be used instead.

Parameter	Adjustment	Description	Adjust to value
1201	G voltage trip	Generator measurement type	Ph-N
1202	BB voltage trip	Busbar measurement type	Ph-N
6004	G nom. voltage	Phase-neutral voltage of the generator	120 V AC
6041	G transformer	Primary voltage of the G voltage transformer (if installed)	120 V AC
6042	G transformer	Secondary voltage of the G voltage transformer (if installed)	120 V AC
6051	BB transformer set 1	Primary voltage of the BB voltage transformer (if installed)	120 V AC
6052	BB transformer set 1	Secondary voltage of the BB voltage transformer (if installed)	120 V AC
6053	BB nom. voltage set 1	Phase-neutral voltage of the busbar	120 V AC

NOTE The measurement U_{L3L1} shows 240 V AC. The voltage alarm set points refer to the nominal voltage 120 V AC, and U_{L3L1} does not activate any alarm.

NOTE The AGC has two sets of BB transformer settings, which can be enabled individually in this measurement system.

2.2.3 Single phase system

The single phase system consists of one phase and the neutral.

The table below contains the parameters to make the system ready for single phase measuring.

The example below is with 230 V AC, which can be connected directly to the AGC's terminals without the use of a voltage transformer. If a voltage transformer is necessary, the nominal values of the transformer should be used instead.

Setting	Adjustment	Description	Adjust to value
6004	G nom. voltage	Phase-neutral voltage of the generator	230 V AC
6041	G transformer	Primary voltage of the G voltage transformer (if installed)	230 V AC
6042	G transformer	Secondary voltage of the G voltage transformer (if installed)	230 V AC
6051	BB transformer set 1	Primary voltage of the BB voltage transformer (if installed)	230 V AC
6052	BB transformer set 1	Secondary voltage of the BB voltage transformer (if installed)	230 V AC
6053	BB nom. voltage set 1	Phase-neutral voltage of the busbar	230 V AC

NOTE The voltage alarms refer to U_{NOM} (230 V AC).
NOTE The AGC has two sets of BB transformer settings, which can be enabled individually in this measurement system.

2.2.4 Reactive power method

Historically, the AGC-4 Mk II has measured the reactive power based on the phase-phase voltage and current. For increased accuracy during current unbalance with significant voltage unbalance, select **Q via U N-Ph and I** in parameter 9132.

Parameter	Name	Range	Default	Details
9132	Q calc method	Q via U Ph-Ph and I Q via U Ph-N and I	Q via U Ph-Ph and I	**Q via U Ph-Ph and I**: The reactive power is based on the phase-phase voltage and current. **Q via U N-Ph and I**: The reactive power is based on the phase-neutral voltage and current.

NOTICE

Option A20 automatically changes parameter 9132

When option A20 (IEEE 1547-2018 grid protection) is activated, parameter 9132 is automatically changed to **Q via U N-Ph and I**. If option A20 is deactivated, parameter 9132 is not reset.

More information
See **Activating option A20** in **Option A20**, and **Deactivating option A20** in **Option A10** for how to change option A20.

2.3 Nominal settings

The AGC holds four sets of nominal settings, configured in channels 6001 to 6036. It is possible to switch between the nominal settings 1 to 4, to match different voltages and frequencies. Nominal settings 1 (6001 to 6007) are the nominal settings that are used as default. See *Switch between the nominal settings* for more information.

The AGC holds two sets of nominal settings for the busbar, configured in channels 6051 to 6063. Each set consists of a nominal as well as a primary and secondary voltage value. The "U primary" and "U secondary" are used to define the primary and secondary voltage values, if any measurement transformers are installed. If no voltage transformer is installed between generator and busbar, select "BB Unom = G Unom" in channel 6054. With this function activated, none of the BB nominal settings will be considered. Instead, the nominal BB voltage will be considered equal to nominal generator voltage.

2.3.1 Switch between the nominal settings

The four sets of nominal settings can be individually configured. The AGC is able to switch between the different sets of nominal settings, which enables the use of a specific set of nominal settings related to a specific application or situation.

NOTE If no busbar voltage transformer is present, the primary and secondary side values can be set to generator nominal value, and parameter 6054 is set to *BB Unom = G Unom*.

The rental industry uses this function, for example, with mobile gensets, where switching frequency and voltage is required. Stationary gensets can also use this feature. For example, for an AMF situation, it may be desirable to increase the nominal power and current settings to achieve increased tolerance regarding the protections.

Activation

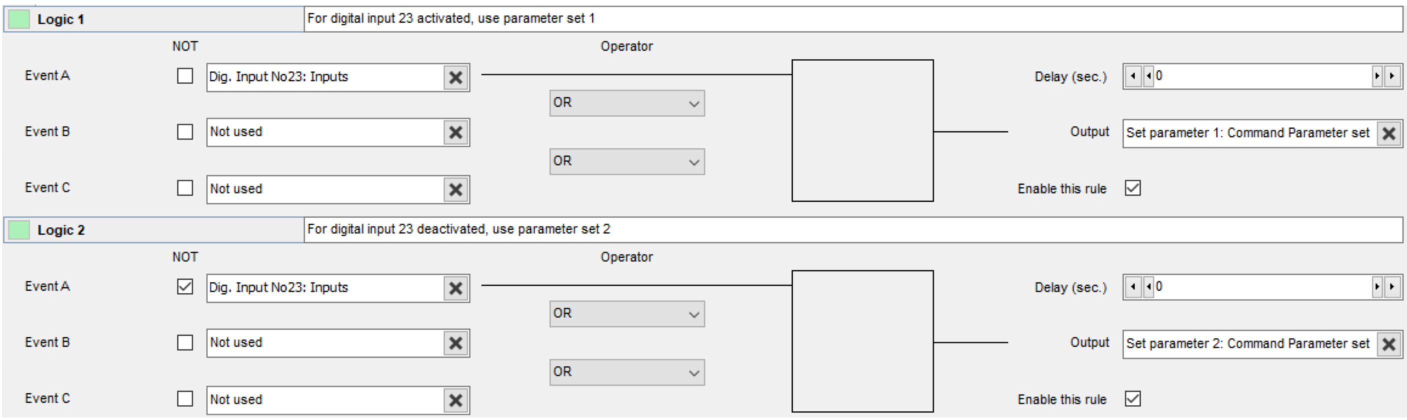
Manual switching between the nominal set points can be done using a digital input, AOP or menu 6006.

NOTE When using M-Logic, any event can be used to activate an automatic switching of nominal parameter sets.

Digital input

M-Logic is used when a digital input is needed to switch between the four sets of nominal settings. Select the required input among the input events, and select the nominal settings in the outputs.

M-Logic and digital input example

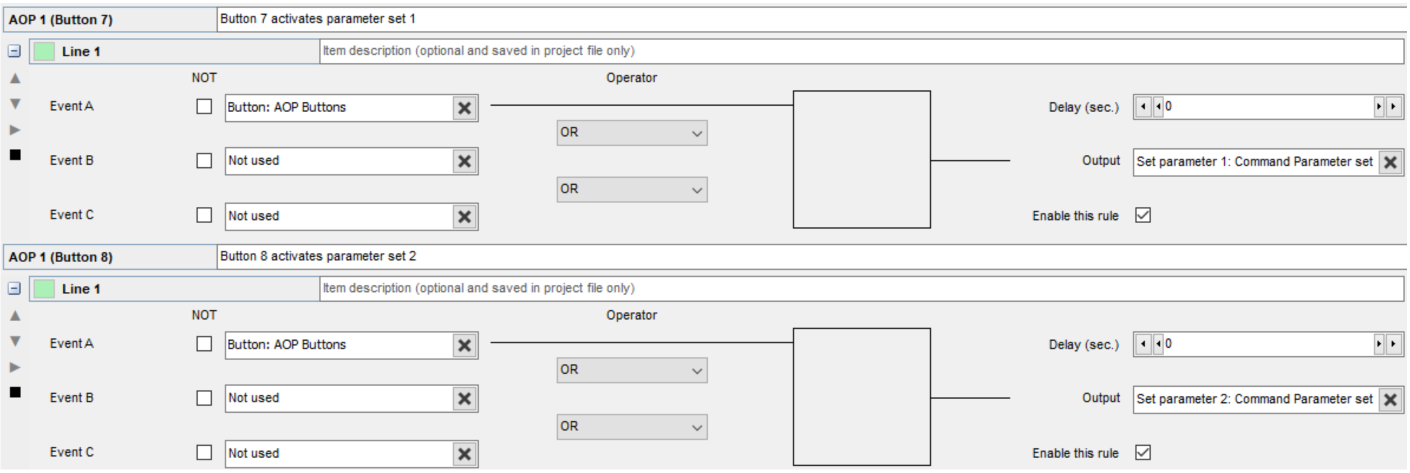


NOTE See the *Help* file in the PC utility software for details.

AOP

M-Logic is used when the AOP is used to switch between the four sets of nominal settings. Select the required AOP push-button among the input events, and select the nominal settings in the outputs.

AOP example



NOTE See the *Help* file in the PC utility software for details.

Four nominal settings of GOV/AVR offsets

Use menu 6006 to select the required set of nominal settings (1 to 4). The nominal setting of GOV/AVR offset follows the setting in 6006, meaning: nominal setting 1 (6001 to 6005) follows the GOV/AVR offset in 2550.

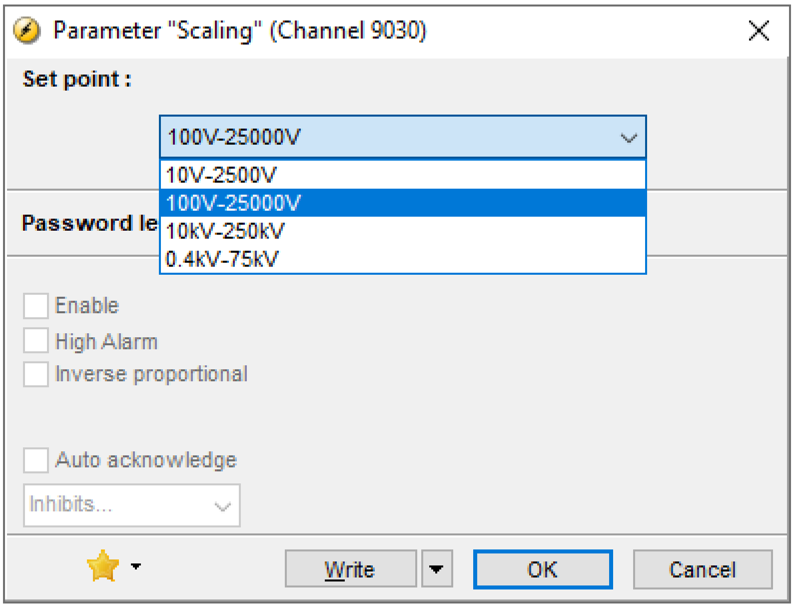
Regulation	2550	GOV outp offset	133	50	%
Regulation	2551	GOV outp offset	1633	50	%
Regulation	2552	GOV outp offset	1634	50	%
Regulation	2553	GOV outp offset	1635	50	%

Regulation	2670	AVR outp offset	161	50	%
Regulation	2671	AVR outp offset	1636	50	%
Regulation	2672	AVR outp offset	1637	50	%
Regulation	2673	AVR outp offset	1638	50	%

NOTE Switching between the two *BB nominal settings* (6050 and 6060) is done in the same way as explained above (channel 6054).

2.3.2 Scaling

The default voltage scaling is 100 V to 25000 V (parameter 9030). To handle applications above 25000 V or below 100 V, adjust the input range so it matches the actual value of the primary voltage transformer. Master password level access is required to change this parameter.



Changing the voltage scaling changes the ranges for voltage, power and transducer output parameters.

Table 2.1 Example of effect of scaling on power and voltage parameters

Scaling (9030)	Power nominal settings range (6002, 6012, 6022, 6032)	Voltage nominal settings range (Generator 6004, 6014, 6024, 6034; Busbar 6053, 6063)	Transformer ratio settings range (Generator primary 6041; Busbar primary 6051, 6061)
10 V to 2500 V	1 to 900 kW	10 V to 2500 V	10 V to 2500 V
100 V to 25000 V	10 to 20000 kW	100 V to 25000 V	100 V to 25000 V
0.4 kV to 75 kV	0.1 to 90 MW	0.4 kV to 75 kV	0.4 kV to 75 kV
10 kV to 250 kV	1 to 900 MW	10 kV to 250 kV	10 kV to 250 kV

NOTICE

Incorrect configuration is dangerous

Correct all nominal values and the primary VT settings after the scaling (parameter 9030) is changed.

2.4 Applications

2.4.1 Applications and genset modes

How to configure an application on AGC-4
See our tutorial on How to configure an application on AGC-4 for help and guidance.

The controller can be used for the applications listed in the table below.

Application	Type	Details
Automatic Mains Failure (no back sync.)	Single DG or Standard	
Automatic Mains Failure (with back sync.)	Single DG or Standard	
Island operation	Single DG or Standard	
Fixed power/base load	Single DG or Standard	
Peak shaving	Single DG or Standard	
Load takeover	Single DG or Standard	
Mains power export (fixed power to mains)	Single DG or Standard	
Multiple gensets, analogue load sharing	Single DG or Standard*	Requires hardware option M12.
Multiple gensets, power management	Standard	Requires option G5.
With up to 16 x ASC-4	Standard	ASC-4 ID range is 25 to 40. ASC SW 4.06.0+. Requires option G5 in the AGC-4 Mk II.
With up to 8 x ALC-4	Standard	ALC-4 ID range is 25 to 40. ALC SW 4.01.0+. Requires option G5 in the AGC-4 Mk II.
Remote maintenance with one genset	Single DG	Requires option H12.x and a remote maintenance box from DEIF.
Remote maintenance with multiple gensets	Standard	Requires options T4, G5, H12.x and a remote maintenance box from DEIF.

NOTE * M-Logic is required to force analogue load sharing in a standard application.

Genset mode	Running mode				
	Auto	Semi	Test	Man	Block
Automatic Mains Failure (no back sync.)	●	●	●	●	●
Automatic Mains Failure (with back sync.)	●	●	●	●	●
Island operation	●	●	●	●	●
Fixed power/base load	●	●	●	●	●
Peak shaving	●	●	●	●	●
Load takeover	●	●	●	●	●
Mains power export	●	●	●	●	●

Genset mode	Running mode				
Multiple gensets, analogue load sharing (hardware option M12)	●	●	●	●	●
Multiple gensets, power management	●	●	●	●	●
Remote maintenance with one genset		●			●

NOTE For a general description of the modes, see Controller modes.

2.4.2 AMF (no back synchronisation)

Auto mode description

The controller automatically starts the genset and switches to generator supply at a mains failure after an adjustable delay time. It is possible to adjust the controller to change to genset operation in two different ways.

1. The mains breaker will be opened at genset start-up.
2. The mains breaker will remain closed until the genset is running, and the genset voltage and frequency is OK.

In both cases, the generator breaker will be closed when the generator voltage and frequency is OK, and the mains breaker is open.

When the mains returns, the controller will switch back to mains supply and cool down and stop the genset. The switching back to mains supply is done without back synchronisation when the adjusted *Mains OK delay* has expired.

Semi-auto mode description

When the generator breaker is closed, the controller will use the nominal frequency as the set point for the speed governor. If AVR control is used, then the nominal voltage is used as set point.

NOTE For a general description of the modes, see Controller modes.

2.4.3 AMF (with back synchronisation)

Auto mode description

The controller automatically starts the genset and switches to generator supply at a mains failure after an adjustable delay time. It is possible to adjust the controller to change to genset operation in two different ways:

1. The mains breaker will be opened at genset start-up.
2. The mains breaker will remain closed until the genset is running, and the genset voltage and frequency is OK.

In both cases, the generator breaker will be closed when the generator voltage and frequency is OK, and the mains breaker is open.

When the mains returns, the controller will synchronise the mains breaker to the busbar when the "Mains OK delay" has expired. Then the genset cools down and stops.

NOTE The automatic mains failure mode can be combined with the *Overlap* function. In that case, the generator breaker and the mains breaker will never be closed at the same time for a longer period than the adjusted *Overlap* time.

Semi-auto mode description

When the generator breaker is closed and the mains breaker is opened, the controller will use the nominal frequency as the set point for the speed governor. If AVR control is used, the nominal voltage is used as the set point.

When the generator is paralleled to the mains, the governor regulation will no longer be active. If AVR control is used, then the set point will either be adjusted power factor or reactive power (7050 Fixed power set).

NOTE For a general description of the modes, see Controller modes.

2.4.4 Island operation

Auto mode description

The controller automatically starts the genset and closes the generator breaker at a digital start command. When the stop command is given, the generator breaker is tripped, and the genset will be stopped after a cooling down period. The start and stop commands are used by activating and deactivating a digital input or with the time-dependent start/stop commands. If the *time-dependent start/stop* commands are to be used, then the auto mode must also be used.

Semi-auto mode description

When the generator breaker is closed, the controller will use the nominal frequency as set point for the speed governor. If AVR control is used, the nominal voltage is used as set point.

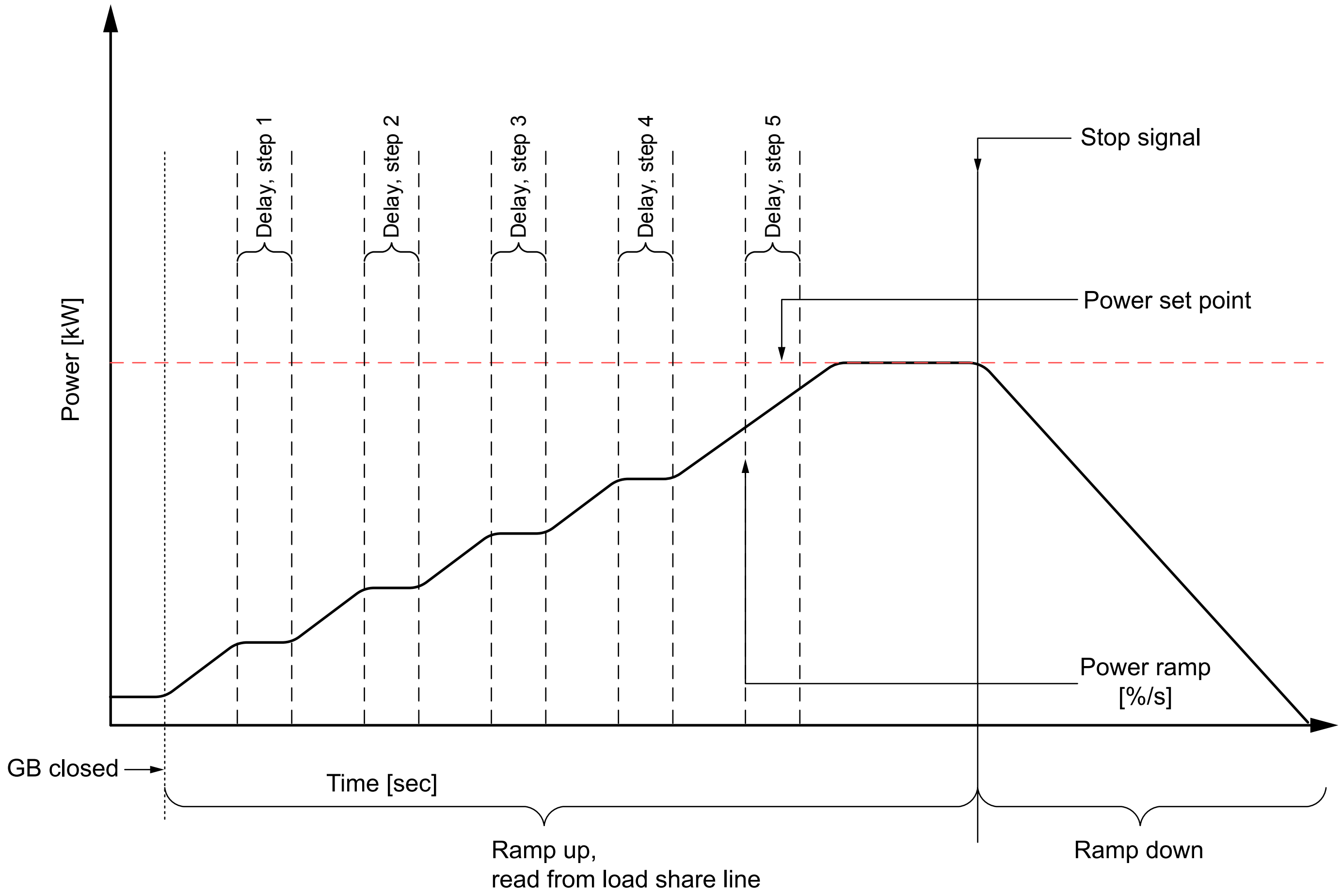
NOTE For a general description of the modes, see Controller modes.

2.4.5 Power ramp

"Power ramp up" (parameter 261x) and "Power ramp down" (parameter 262x) are used when the genset is connected to another supply source.

2610 Power ramp up	
Ramp speed 1	Defines the slope of ramp up 1
Delay point	At this point, the ramp up is cancelled until the delay has expired
Delay	When this delay has expired, the ramp up is continued from the delay point
Island ramp	Enable ramping in Island mode
Steps	Defines the number of ramp steps
Ramp speed 2	Defines the slope of ramp up 2

2620 Power ramp down	
Ramp speed 1	Defines the slope of ramp down 1 (used for de-load as well)
Breaker open point	The amount of power accepted when opening the breaker
Ramp speed 2	Defines the slope of ramp down 2 (not used for de-load)
Automatic ramp selection	When "Auto ramp select" is disabled, ramp 2 can only be enabled with M-Logic



Ramp up with load steps

When the GB is closed, the power set point continues to rise in ramp-up steps, determined by the number of steps in menu 2615. If the delay point is set to 20 % and the number of load steps is set to 3, the genset will ramp to 20 %, wait the configured delay time, ramp to 40 %, wait, ramp to 60 %, wait and then ramp to the present power set point.

Freeze power ramp

A way to define the ramp up steps is to use the freeze power ramp command in M-Logic.

Freeze power ramp active: The power ramp will stop at any point of the power ramp, and this set point will be maintained as long as the function is active. If the function is activated while ramping from one delay point to another, the ramp will be fixed until the function is deactivated again.

1. The power ramp will stop at any point of the power ramp, and this set point will be maintained as long as the function is active.
2. If the function is activated while ramping from one delay point to another, the ramp will be fixed until the function is deactivated again.
3. If the function is activated while the delay timer is timing out, the timer will be stopped and will not continue until the function is deactivated again.

NOTE The delay starts running when the GB has been closed.

Power ramp 1

This is the primarily used power ramp. Power ramp 1 is only ignored during "frequency-dependent power droop" or if power ramp 2 is activated with M-Logic.

Power ramp 2

Parameters 2616 and 2623 define the slope of the second power ramp. This is a secondary power ramp mostly used for "frequency-dependent power droop", but it can also be activated with any M-Logic event. Parameter 2624 (automatic ramp selection) determines if the ramp 2 is activated by droop or M-Logic. If automatic "ramp selection" is activated, then the second ramp is enabled during power droop. If it is disabled, then the second ramp can only be activated by M-Logic.

2.4.6 Q ramp

A ramp function for reactive power regulation can be activated. This ramp is used when the controller increases or decreases the reactive power. Configure these parameters in the USW.

Text	Parameter	Default	Range	Description
Q ramp to setp.	2821	2 %/s	0.1 to 20 %/s	Ramp up for reactive power
Q ramp to zero	2822	2 %/s	0.1 to 20 %/s	Ramp down for reactive power
Q ramp enable	2823	OFF	OFF Linear Time constant	**OFF**: Deactivate the ramp. **Linear**: Parameters 2821 and 2822 are used. **Time constant**: Parameter 2824 is used.
Q time constant	2824	2 s	1 to 30 s	PT1-based time constant, used if **Time constant** is selected in parameter 2823.

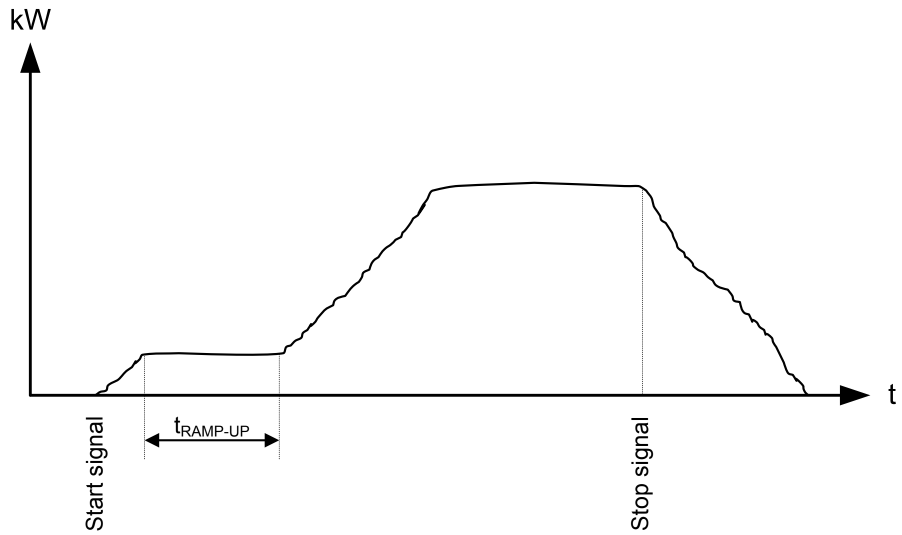
NOTE There is no ramp for cos phi regulation.

2.4.7 Fixed power/base load

Auto mode description

The controller automatically starts the genset and synchronises to the mains when the digital input "auto start/stop" is activated. After the generator breaker closure, the controller ramps up the load to the set point level. When the stop command is given, the genset is de-loaded and stopped after the cooling down period. The start and stop commands are used by activating and deactivating a digital input or with the time-dependent start/stop commands. If the *time-dependent start/stop* commands are to be used, then the auto mode must also be used.

Diagram, fixed power - principle



Semi-auto mode description

When the generator breaker is closed and the mains breaker is opened, the controller will use the nominal frequency as the set point for the speed governor. If AVR control is used, the nominal voltage is used as set point.

When the generator is paralleled to the mains, the generator power will be increased to the fixed power set point. If AVR control is used, then the set point will either be adjusted power factor or reactive power (7050 Fixed power set).

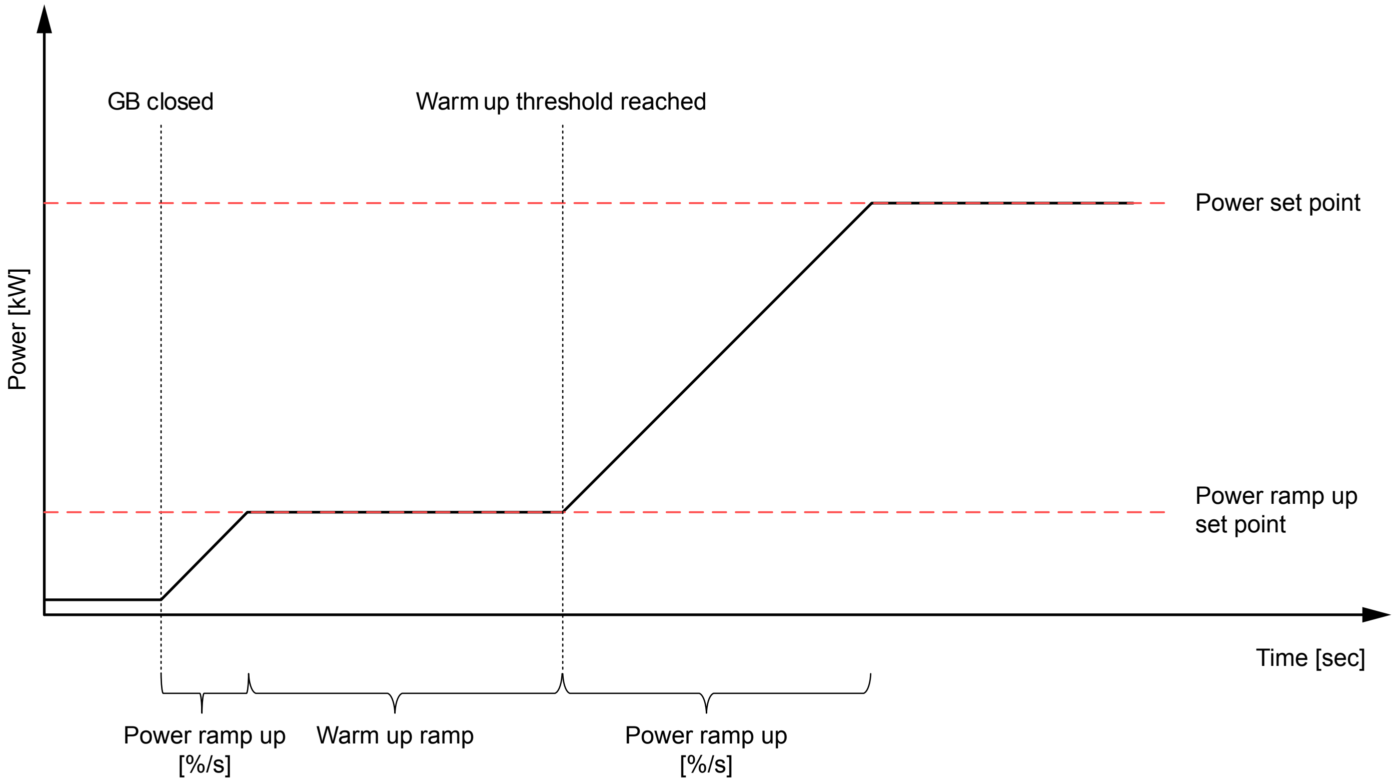
7050 Fixed Power Set	
Power set	The amount of power the genset will produce.

NOTE The values in menu 7050 set the cos phi. This is not the PF value displayed in the display. Cos phi and PF are only equal if it is a true sinusoidal wave.

NOTE For a general description of the modes, see Controller modes.

2.4.8 Warm up ramp

Warm up ramp is a function that limits the power output until a pre-configured condition has been met, like, for example, the engine has reached operating temperature which will greatly reduce stress on the engine.



The warm up ramp activation is enabled and the input is configured via *Warm up type* (parameter 2961). The activation of the warm up ramp input limits the available power of the genset to the percentage level configured in *Power ramp up* (parameter 2612).

If the type is configured as M-Logic, the input must go low before warm up ramp is deactivated. If the type is configured as a multi-input or an EIC temperature input, the deactivation occurs when the temperature is above the threshold configured in *Warm up thresh.* (parameter 2962).

NOTE When warm up ramp is activated, the standard function *Power ramp up* is replaced, which means that the load/ steps and the timer are disabled.

2.4.9 Peak shaving

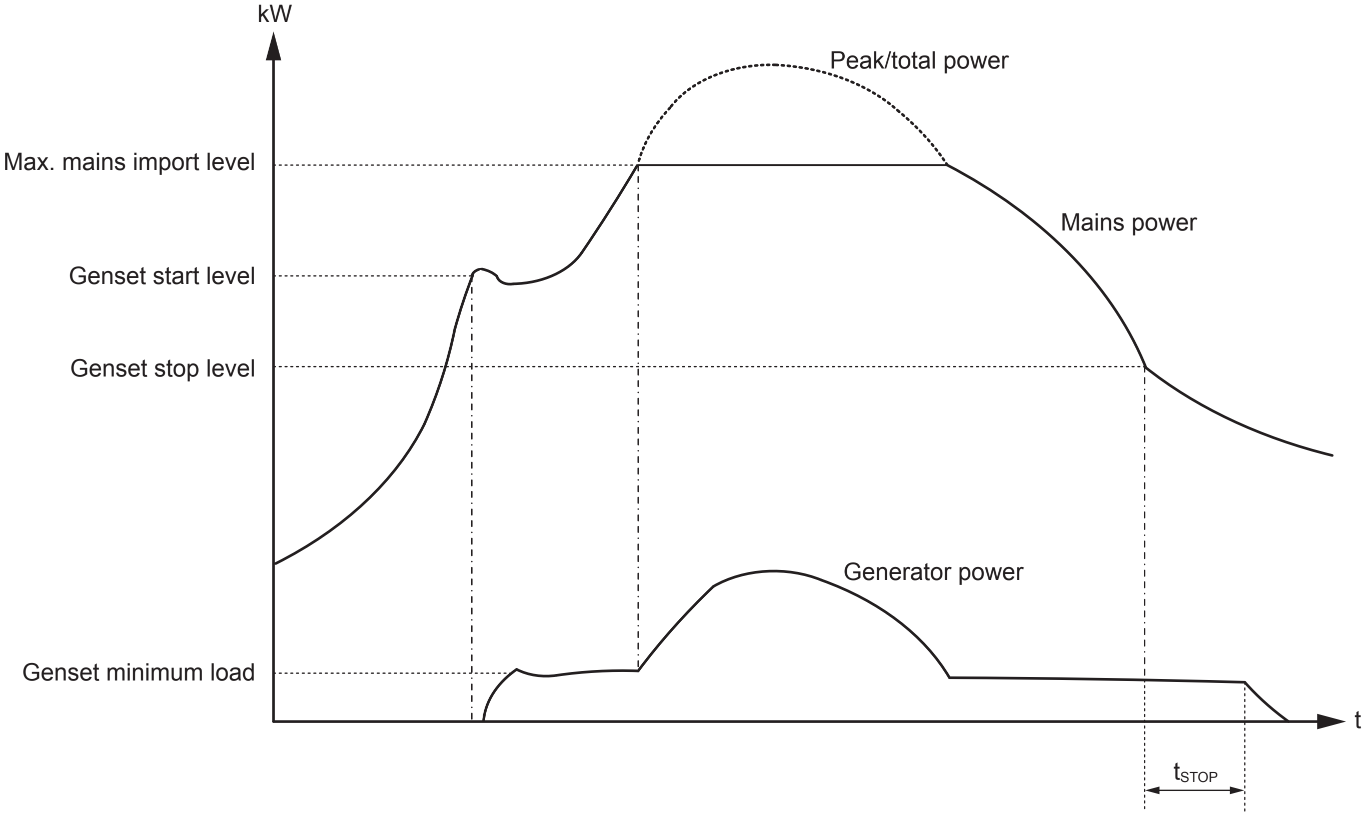
Auto mode description

The genset will start at a pre-defined mains import level and run at a fixed minimum load, for example 10 %. When the mains import increases above the maximum mains import set point, the genset will supply the extra load in order to maintain the mains import at the maximum import level.

When the load drops below the maximum mains import set point, the genset will run at minimum load again. When the mains import and the generator load decrease below the stop set point, the genset will cool down and stop.

A 4 to 20 mA transducer is used for indication of the power imported from the mains, see Mains power transducer.

Diagram, peak shaving – example



Semi-auto mode description

When the generator breaker is closed and the mains breaker is opened, the controller will use the nominal frequency as set point for the speed governor. If AVR control is used, the nominal voltage is used as set point.

When the generator is paralleled to the mains, the generator will be controlled according to the peak shaving set point. So the maximum mains import will not be exceeded in spite of the semi- auto mode. If AVR control is used, then the set point will either be adjusted power factor or reactive power (7050 Fixed power set).

Peak shaving parameters

Menu		Description
7000 Mains power	Day and night	The mains power import limits for the peak shaving.
7010 Daytime period		These settings define the daytime period. The hours outside the daytime period are considered to be the night-time period.
7020 Start generator	Start set point	The start set point is in percent of the day and night settings in menu 7000 Mains power.
	Delay	The genset will start when the start set point has been exceeded and this delay has expired.
	Load	The minimum load the genset will produce when parallel to mains.
7030 Stop generator	Stop set point	The stop set point is in percent of the day and night settings in menu 7000 Mains power.
	Delay	The genset will stop when the stop set point has been exceeded and this delay has expired.

NOTE Parameters 7020 and 7030 are used to define the starting and stopping point of an application without power management (option G5). If power management is used, then load-dependent start and stop parameters are used. For more information on load-dependent start and stop, see **Option G5**.

NOTE For a general description of the modes, see Controller modes.

2.4.10 Load takeover

Auto mode description - Back synchronising ON

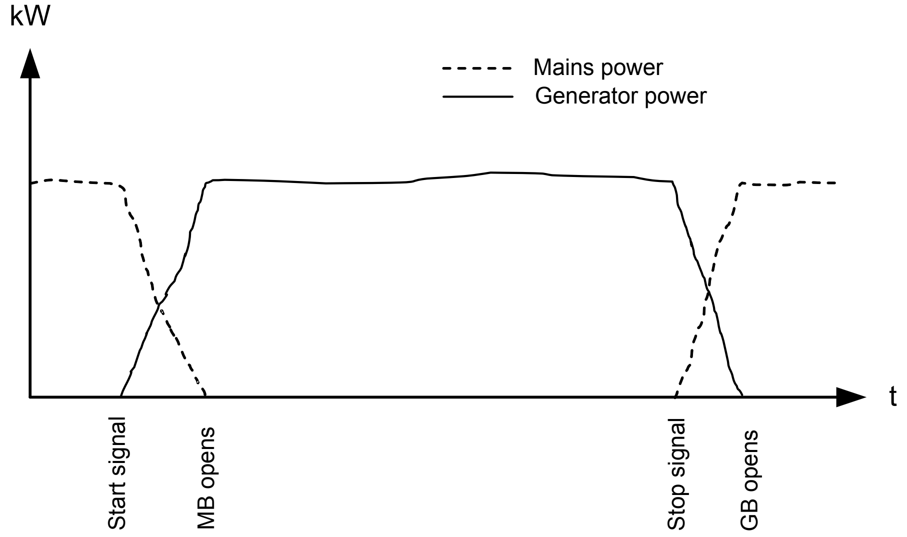
The purpose of the load takeover mode is to transfer the load imported from the mains to the genset for operation on generator supply only.

When the start command is given, the genset will start and synchronise the generator breaker to the busbar that is being supplied by the mains. When the generator breaker is closed, the imported load is decreased (the power is being transferred to the genset) until the load is at the open breaker point. Then the mains breaker opens.

When the stop command is given, the mains breaker is synchronised to the busbar and after closure the genset is deloaded, cooled down and stopped.

A 4-20 mA transducer is used for indication of the power imported from the mains, see the *Mains transducer* description later in this document.

Diagram, load takeover - example



NOTE The load takeover mode can be combined with the overlap function. In that case, the generator and the mains breakers will never be closed at the same time for a longer period than the adjusted *overlap* time.

NOTE If the imported load is higher than the nominal genset power, an alarm appears and the load takeover sequence is paused.

Auto mode description - Back synchronising OFF

When the start command is given, the genset will start. When the frequency and voltage is OK, the mains breaker is opened and the generator breaker is closed. Now, the generator supplies the load until the stop command is given. Then, the generator breaker opens and the mains breaker closes. The genset cools down and stops.

NOTE If the imported load is higher than the nominal genset, an alarm appears and the load takeover sequence is paused.

Semi-auto mode description

When the generator breaker is closed and the mains breaker is opened, the controller will use the nominal frequency as set point for the speed governor. If AVR control is used, the nominal voltage is used as set point.

When the generator is paralleled to the mains, it will be controlled so the imported power from the mains will be kept at 0 kW. If AVR control is used, then the set point will either be adjusted power factor or reactive power (7050 *Fixed power set*).

NOTE For a general description of the modes, see Controller modes.

2.4.11 Mains power export (fixed power to mains)

Auto mode description

The mains power export mode can be used to maintain a constant level of power through the mains breaker. The power can be exported to the mains or imported from the mains, but always at a constant level.

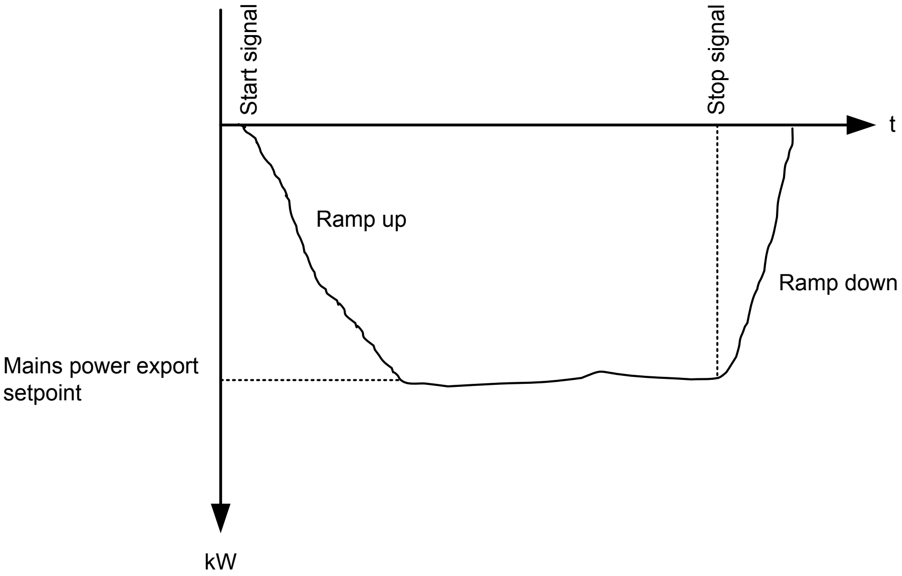
NOTE If a fixed level of imported power must be used, it is still the mains power export mode that must be selected! This mode covers import as well as export.

The genset starts as a result of a digital start command. It synchronises to the mains and will start to export power to the mains. The amount of power exported will be kept at a fixed level regardless of the load on the busbar (the factory).

The stop command will cause the genset to deload and trip the generator breaker. Afterwards, it will cool down and stop.

A 4-20 mA transducer is used for indication of the power exported from the mains, see Mains power transducer.

Diagram, mains power export - example



NOTE Note that the set point of the mains power export can be 0 kW. This means that the genset will be parallel to the mains but no power import or export.

Semi-auto mode description

When the generator breaker is closed and the mains breaker is opened, the controller will use the nominal frequency as set point for the speed governor. If AVR control is used, the nominal voltage is used as set point.

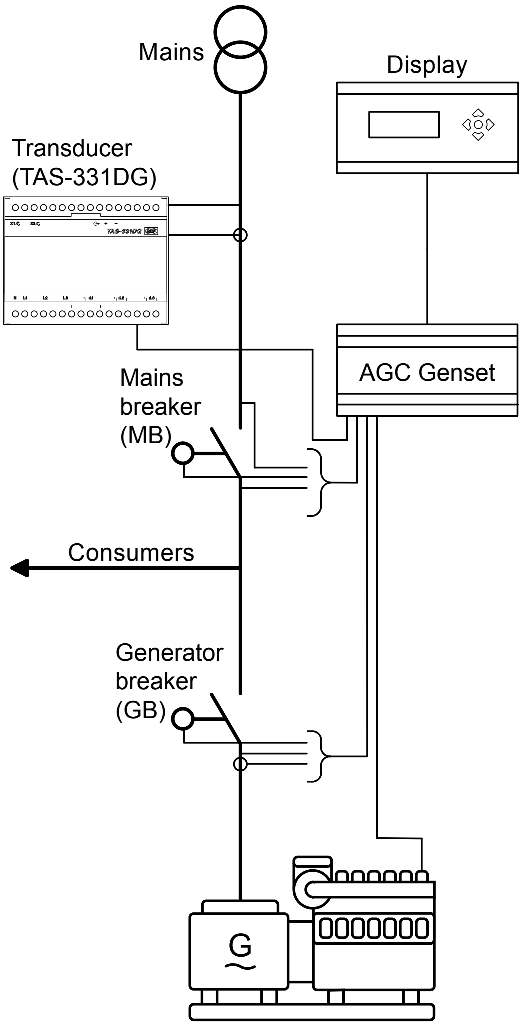
When the generator is paralleled to the mains, it will be controlled according to the mains power export set point. If AVR control is used, then the set point will either be adjusted power factor or reactive power (7050 *Fixed power set*).

NOTE For a general description of the modes, see Controller modes.

2.4.12 Mains power transducer

In applications where export/load takeover is used (mains power export, peak shaving, load takeover), it is necessary to know the power flow on the primary side of the mains breaker. When one controller is used for the application or if a transducer signal is preferred in a power management system, it is possible to use multi-input 102 or CIO 308 1.14 for this purpose.

Below is a single line diagram where a TAS-331 DG transducer is used for measuring the voltage and current before the mains breaker, this is used to calculate the power and based upon this gives a 4-20 mA output.



How to set up

As mentioned, it is necessary to use **multi-input 102 or CIO 308 1.14** for this purpose.

Set up the input for 4-20 mA, and define the range of the transducer in parameter 7261 and 7262. The range is defined with a min. and max. setting where the min. setting corresponds to 4 mA and the max. setting to 20 mA.

P measurement from a transducer

Text	Parameter	Default	Range	Description
Transducer Range	7261	0 kW	0 to 20000 kW*	Maximum active power
Transducer Range	7262	0 kW	-20000 to 0 kW*	Minimum active power
Mains P measure	7263	Multi input 102	Multi input 102 (transducer) CIO308 1.14 (transducer)	Selection of the analogue input

NOTE * Scaling (parameter 9030) affects this range. The range shown is based on a scaling of 100V-25000V.

NOTE As soon as transducer max. or min. settings are changed to a value different from 0, the controller will use the transducer signal.

More information

The information above is for a mains power measurement for a genset controller. For a mains controller, see **Mains functions, Mains power measurement** in **Option G5 Power management**.

2.4.13 Mains reactive power or voltage transducer

It is also possible to use transducers to measure mains voltage or reactive power. To set-up these transducers use menu 7270 (Mains reactive power) and 7280 (Mains voltage).

To be compliant with national grid codes it is often necessary to measure in the grid connection point. Using transducers are the practical solution in case of long distance. See documentation for option A10 for more information.

Q measurement from a transducer

Text	Parameter	Default	Range	Description
Transducer Range	7271	0 kvar	-20000 to 20000 kvar*	Maximum reactive power
Transducer Range	7272	0 kvar	-20000 to 20000 kvar*	Minimum reactive power
Mains Q measure	7273	Multi input 102	Multi input 102 (transducer) CIO308 1.17 (transducer)	Selection of the analogue input

*Note: Scaling (parameter 9030) affects this range. The range shown is based on a scaling of 100V-25000V.

Set up the input for 4-20 mA, and define the range of the transducer in parameter 7271 and 7272. The range is defined with a min. and max. setting where the min. setting corresponds to 4 mA and the max. setting to 20 mA.

U measurement from a transducer

Text	Parameter	Default	Range	Description
Transducer Range	7281	0 V	0 to 25000 V*	Maximum voltage
Transducer Range	7282	0 V	0 to 25000 V*	Minimum voltage
Mains U measure	7283	Multi input 102	Multi input 102 (transducer) CIO308 1.20 (transducer)	Selection of the analogue input
Mains U Ext Nom	7284	400 V	100 to 25000 V*	Nominal grid voltage for the transducer

*Note: Scaling (parameter 9030) affects this range. The range shown is based on a scaling of 100V-25000V.

Set up the input for 4-20 mA, and define the range of the transducer in parameter 7281 and 7282. The range is defined with a min. and max. setting where the min. setting corresponds to 4 mA and the max. setting to 20 mA.

2.5 Controller modes

2.5.1 Semi-auto mode

The controller can be operated in semi-auto mode. Semi-auto means that the controller will not initiate any sequences automatically, as is the case with the auto mode. It will only initiate sequences, if external signals are given.

An external signal may be given in three ways:

1. Push-buttons on the display are used
2. Digital inputs are used
3. Modbus command

NOTE The standard AGC is only equipped with a limited number of digital inputs, see *Digital inputs* in this document and the data sheet for additional information about availability.

When the genset is running in semi-auto mode, the controller will control the speed governor, and the AVR if it is used.

The following sequences can be activated in semi-auto:

Command	Description	Comment
Start	The start sequence is initiated and continues until the genset starts or the maximum number of start attempts has been reached. The frequency (and voltage) will be regulated to make the GB ready to close.	
Stop	The genset will be stopped. After disappearance of the running signal, the stop sequence will continue to be active in the '"extended stop time" period. The genset is stopped with cooling down time.	The cooling down time is cancelled if the stop button is activated twice.
Close GB	The controller will close the generator breaker if the mains breaker is open, synchronise and close the generator breaker if the mains breaker is closed.	When AMF mode is selected, the controller will not regulate after breaker closure.
Open GB	The controller will ramp down and open the generator breaker at the breaker open point if the mains breaker is closed. The controller will open the generator breaker instantly if the mains breaker is open or the genset mode is island mode.	
Close MB	The controller will close the mains breaker if the generator breaker is open, synchronise and close the mains breaker if the generator breaker is closed.	
Open MB	The controller opens the mains breaker instantly.	
Manual GOV UP	The regulator is deactivated and the governor output is activated as long as the GOV input is ON.	
Manual GOV DOWN	The regulator is deactivated and the governor output is activated as long as the GOV input is ON.	
Manual AVR UP	The regulator is deactivated and the AVR output is activated as long as the AVR input is ON.	
Manual AVR DOWN	The regulator is deactivated and the AVR output is activated as long as the AVR input is ON.	

2.5.2 Not in auto

This function can be used for indication or to raise an alarm in case the system is not in Auto. The function is set up in menu 6540.

2.5.3 Test mode

The test mode function is activated by selecting test with the MODE push-button on the display or by activating a digital input.

The settings for the test function are set up in menu 7040.

Parameter	Item	Range	Default	Notes
7041	Set point	1 to 100 %	80 %	Load set point when paralleling to mains.
7042	Timer	0.0 to 999.0 min	5.0 min	Engine run time during the test period. If the timer is set to 0.0 min, the test sequence will be infinite.
7043	Return	DG: Semi auto, Auto, Manual, No change Mains: Semi auto, Auto, No change	DG: No change Mains: Auto	When the test is completed, the controller will return to the selected mode.

Parameter	Item	Range	Default	Notes
				If the DG controller is in the stop sequence in test mode and the mode is changed to semi-auto, the DG will continue to run.
7044	Type	Simple test, Load test, Full test	Simple test	Selection of one of the three types of tests: Simple, Load or Full. Test mode in island operation (genset mode selected to island mode) can only run *Simple* and *Full* test.

NOTE Power management (option G5): Test mode is not available.

Simple test

The simple test will only start the genset and run it at nominal frequency with the generator breaker open. The test will run until the timer expires.

Load test

The load test will start the genset and run it at nominal frequency, synchronise the generator breaker and produce the power typed in the set point in menu 7041. The test will run until the timer expires. To run the load test, *Sync. to mains* must be enabled in menu 7084.

When running a load test sequence, the overlap function is ignored.

Full test

The full test will start the genset and run it at nominal frequency, synchronise the generator breaker and transfer the load to the generator before opening the mains breaker. When the test timer expires, the mains breaker will be synchronised, and the load is transferred back to the mains before the generator breaker is opened and the generator is stopped.

To run the full test, *Sync. to mains* must be enabled in menu 7084.

2.5.4 Manual mode

When manual mode is selected, the genset can be controlled from the display and with digital inputs. The following commands are possible:

Command	Description	Comment
Start	The start sequence is initiated and continues until the genset starts or the maximum number of start attempts has been reached.	No regulation.
Stop	The genset will be stopped. After disappearance of the running signal, the stop sequence will continue to be active in the "extended stop time" period. The genset is stopped with cooling down time.	
Close GB	The controller will close the generator breaker if the mains breaker is open, and synchronise and close the generator breaker if the mains breaker is closed.	No regulation. Sync. failure is deactivated.
Open GB	The controller will open the generator breaker instantly.	
Close MB	The controller will close the mains breaker if the generator breaker is open, and synchronise and close the mains breaker if the generator breaker is closed.	No regulation. Sync. failure is deactivated.
Open MB	The controller will open the mains breaker instantly.	
Manual GOV UP	The controller gives increase signal to the speed governor.	
Manual GOV DOWN	The controller gives decrease signal to the speed governor.	

Command	Description	Comment
Manual AVR UP	The controller gives increase signal to the AVR.	
Manual AVR DOWN	The controller gives decrease signal to the AVR.	

NOTE It is possible to open and close both the generator breaker and the mains breaker in manual mode.

2.5.5 Block mode

When block mode is selected, the controller is locked for certain actions. Block mode can either be selected by pressing the MODE button on the display or by using a digital input. If a digital input is used for block mode, it is important to keep in mind that the input configured to block mode is a continuous signal. This means that when the input is ON the controller is in a blocked state, and when it is OFF the controller returns to the mode it was in before block mode was selected.

NOTE For a German AGC, press the AUS button to activate block mode.

When changing from block mode to any other operating modes from the AGC's display, it is as a minimum required to log in as customer.

NOTE If block mode is selected by using the display after the digital block input is activated, the AGC will stay in block mode after the block input is deactivated. The block mode must now be changed using the display. The block mode can only be changed locally via display or digital input.

Block mode on a genset controller

If the genset controller is in block mode, it cannot start the genset or perform any breaker operations. If the genset is running when block mode is selected, the breaker will be opened and the genset will shut down without cooling down.

The purpose of the block mode is to make sure that the genset does not start during maintenance work, for example.

NOTICE
Mode change precautions
Before the running mode is changed, make sure that nobody is near the genset and that the genset is ready for operation.

NOTICE
Local cranking and starting
The genset can be started from the local engine control panel, if such is installed. Therefore, DEIF recommends avoiding local cranking and starting of the genset.

Block mode on a mains controller

If the mains controller is in block mode, it cannot perform any breaker operations. If any breaker is closed when the mains controller is put into block mode, the mains breaker will be opened, but the tie breaker will remain closed to ensure the genset's ability to support the load.

The purpose of block mode is to make sure that the mains breaker cannot close onto a transformer that is momentarily non-functional due to performance of service. When block mode is used on a mains controller in a power management setup, the system will know that the blocked mains controller will not be available.

Block mode in single DG application

If a genset, which is running in a single DG application with an MB and a GB, is set in block mode, the DG will stop and the GB will open. When block mode is active the DG, the GB and the MB will not be operational, but if the MB was closed when block mode was activated, the MB will stay closed.

NOTE Alarms are not influenced by block mode selection.

More information
Block mode is not the same as the Block fail class. See Fail class for more information about the Block fail class.

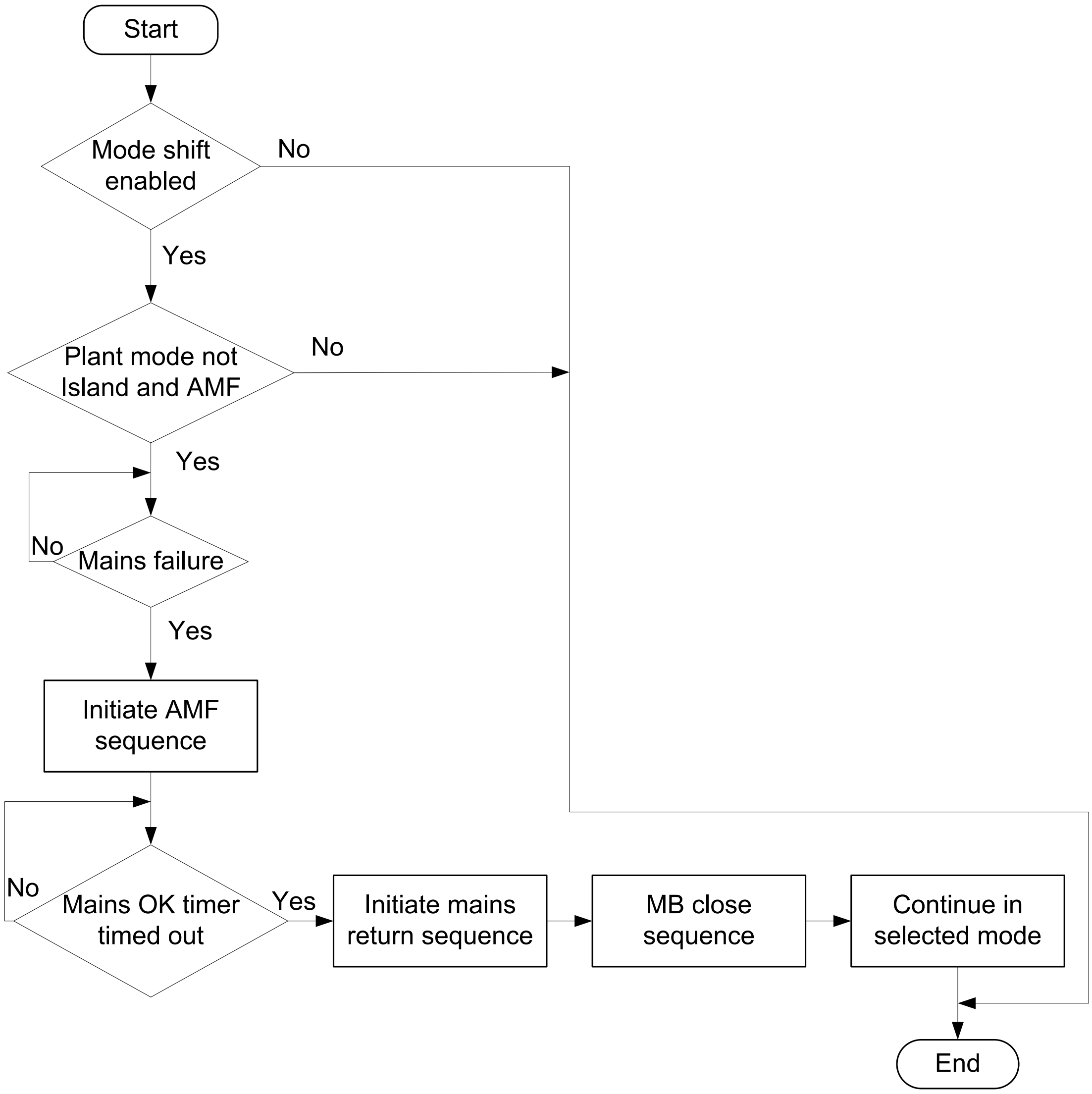
2.6 Flowcharts

Using flowcharts, the principles of the most important functions will be illustrated in the next sections. The functions included are:

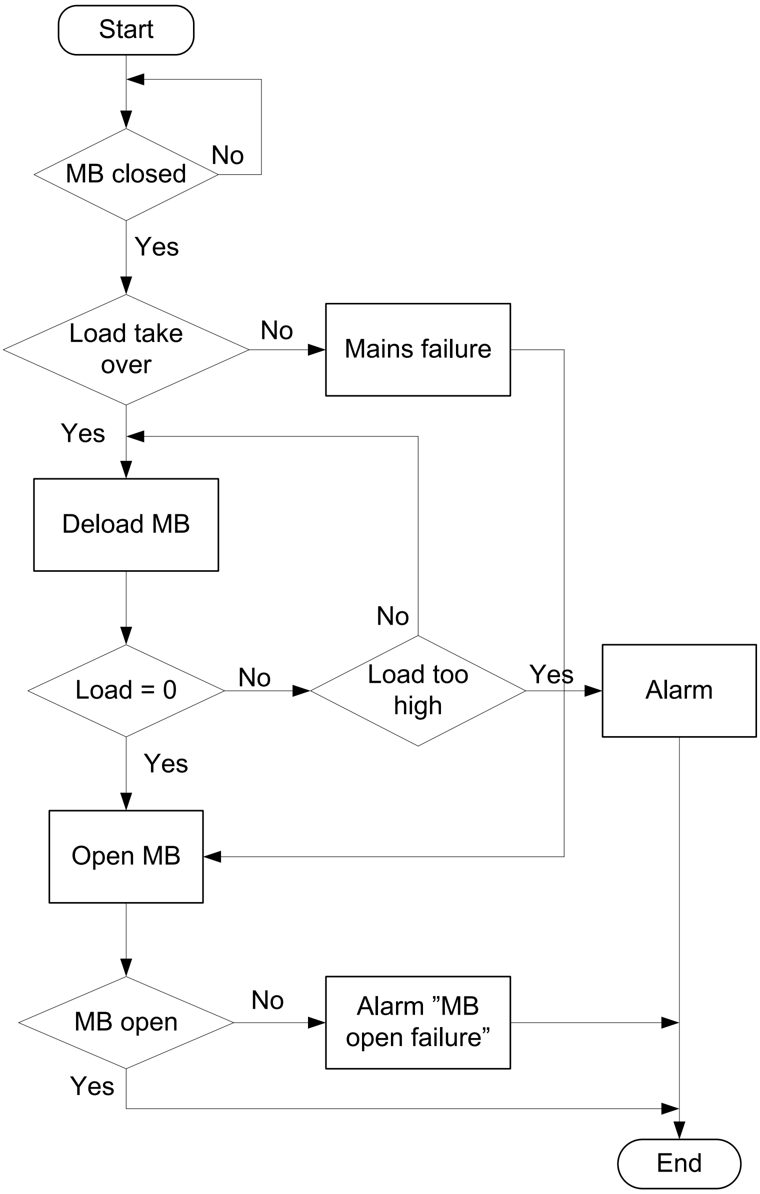
- Mode shift
- MB open sequence
- GB open sequence
- Stop sequence
- Start sequence
- MB close sequence
- GB close sequence
- Fixed power
- Load takeover
- Island operation
- Peak shaving
- Mains power export
- Automatic Mains Failure
- Test sequence

NOTE The simplified flowcharts on the following pages are only for guidance.

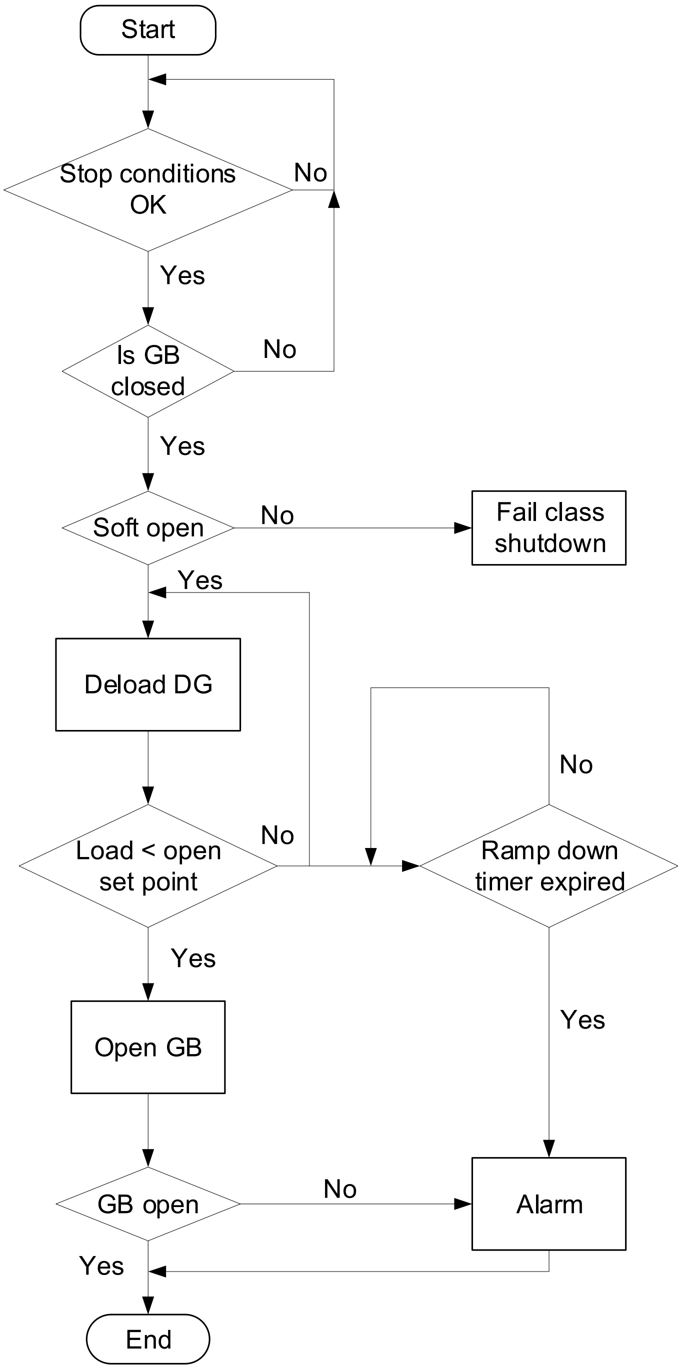
2.6.1 Mode shift



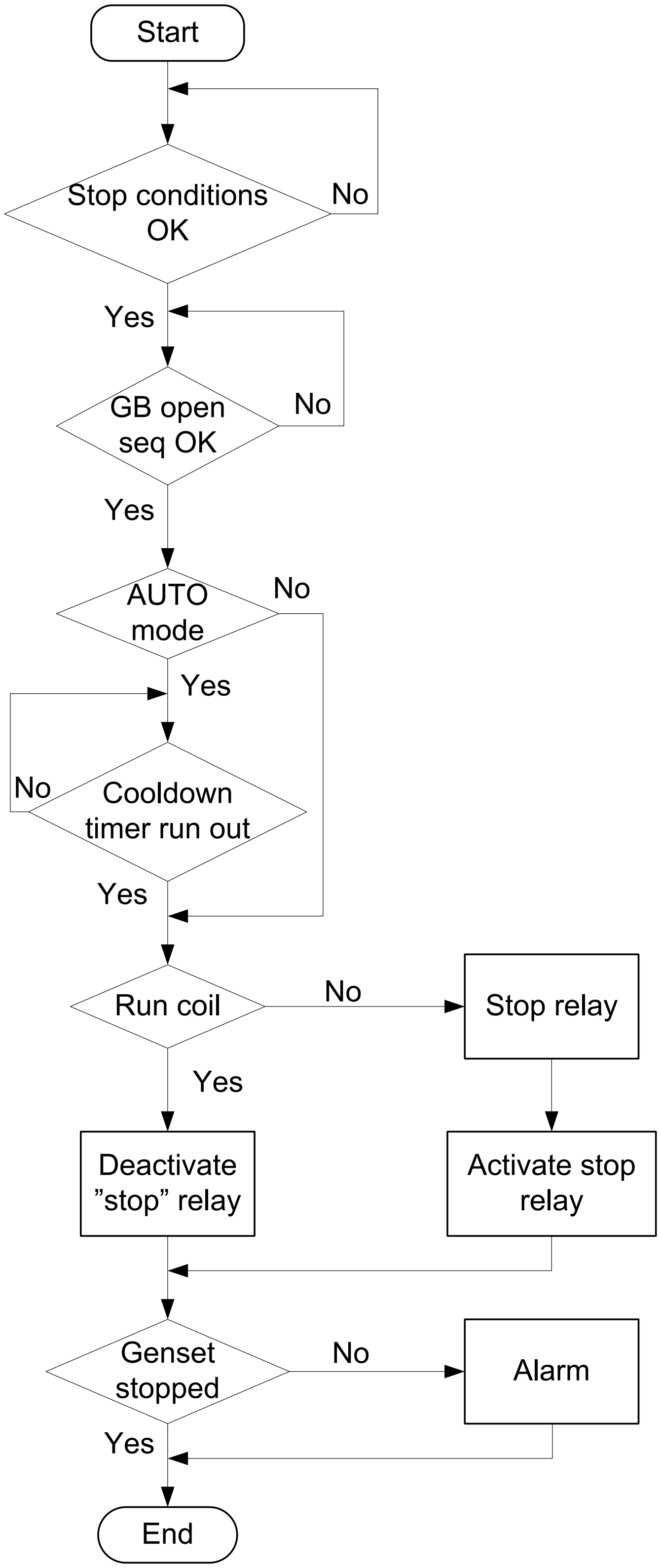
2.6.2 MB open sequence



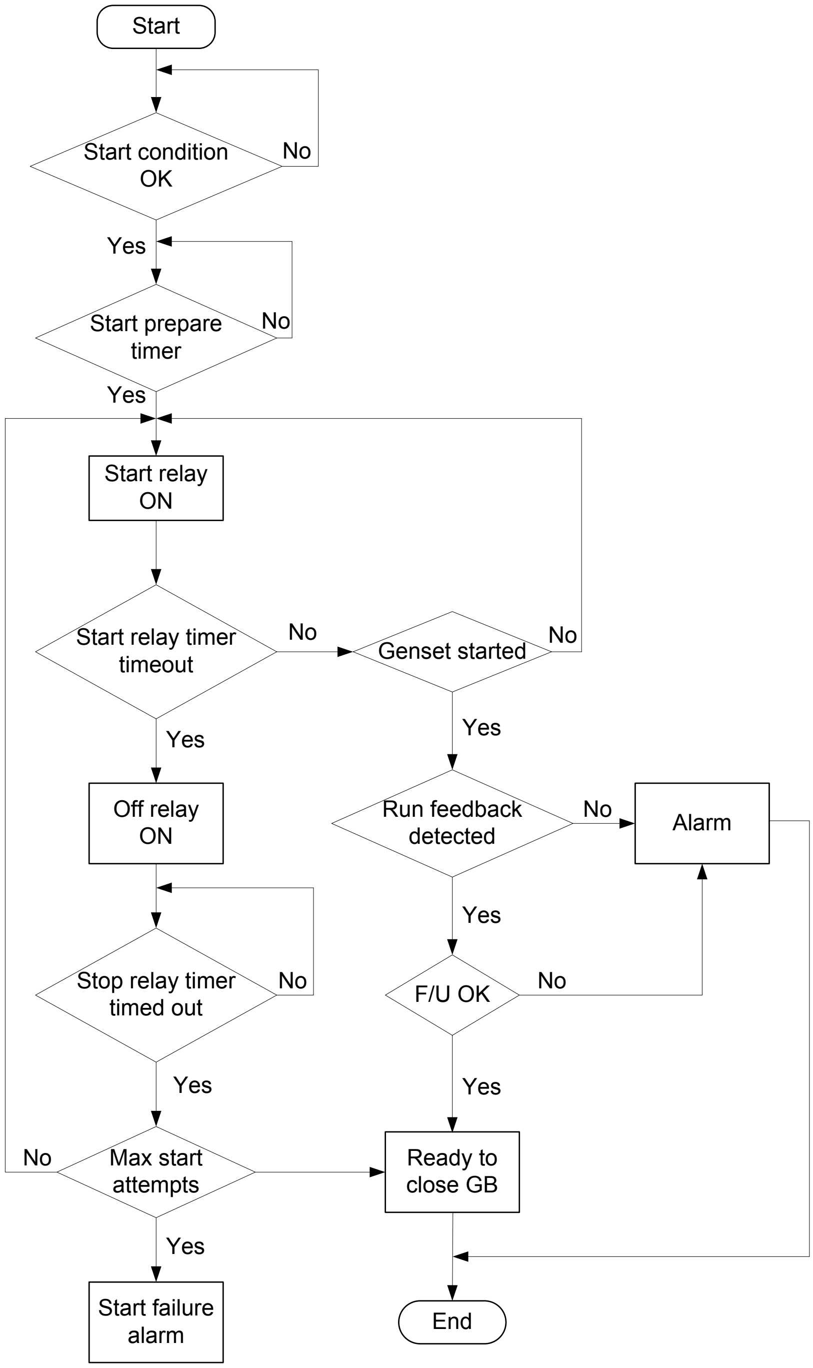
2.6.3 GB open sequence



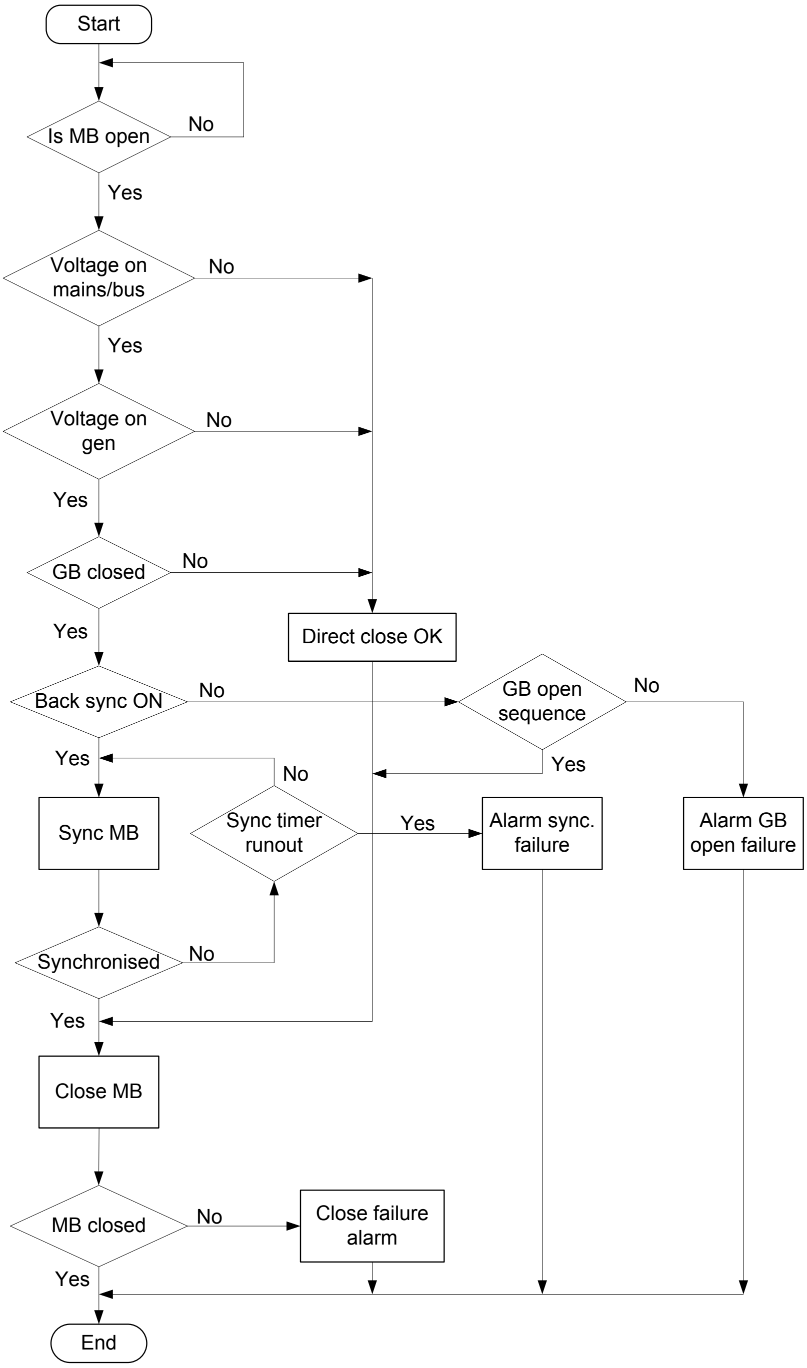
2.6.4 Stop sequence



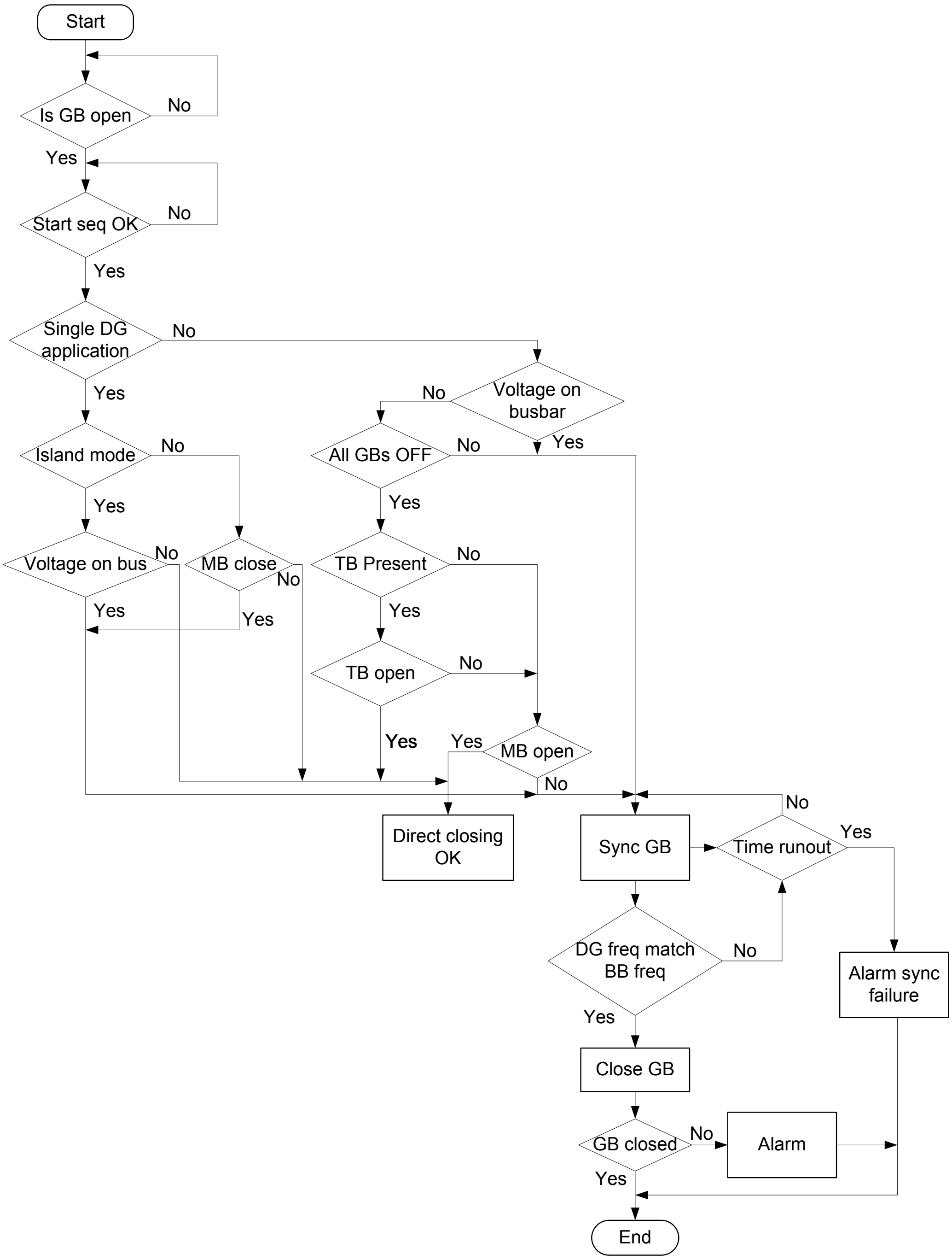
2.6.5 Start sequence



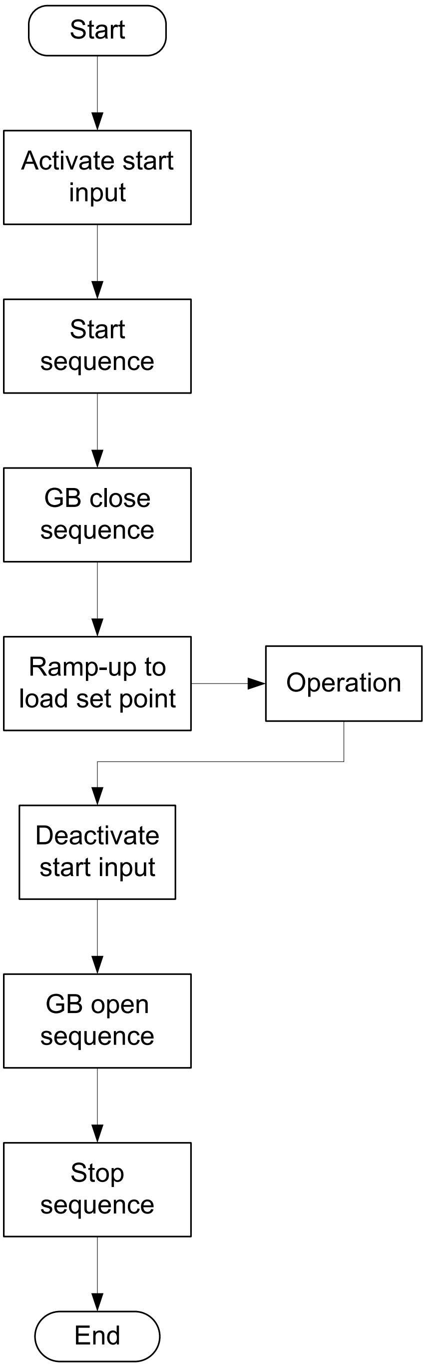
2.6.6 MB close sequence



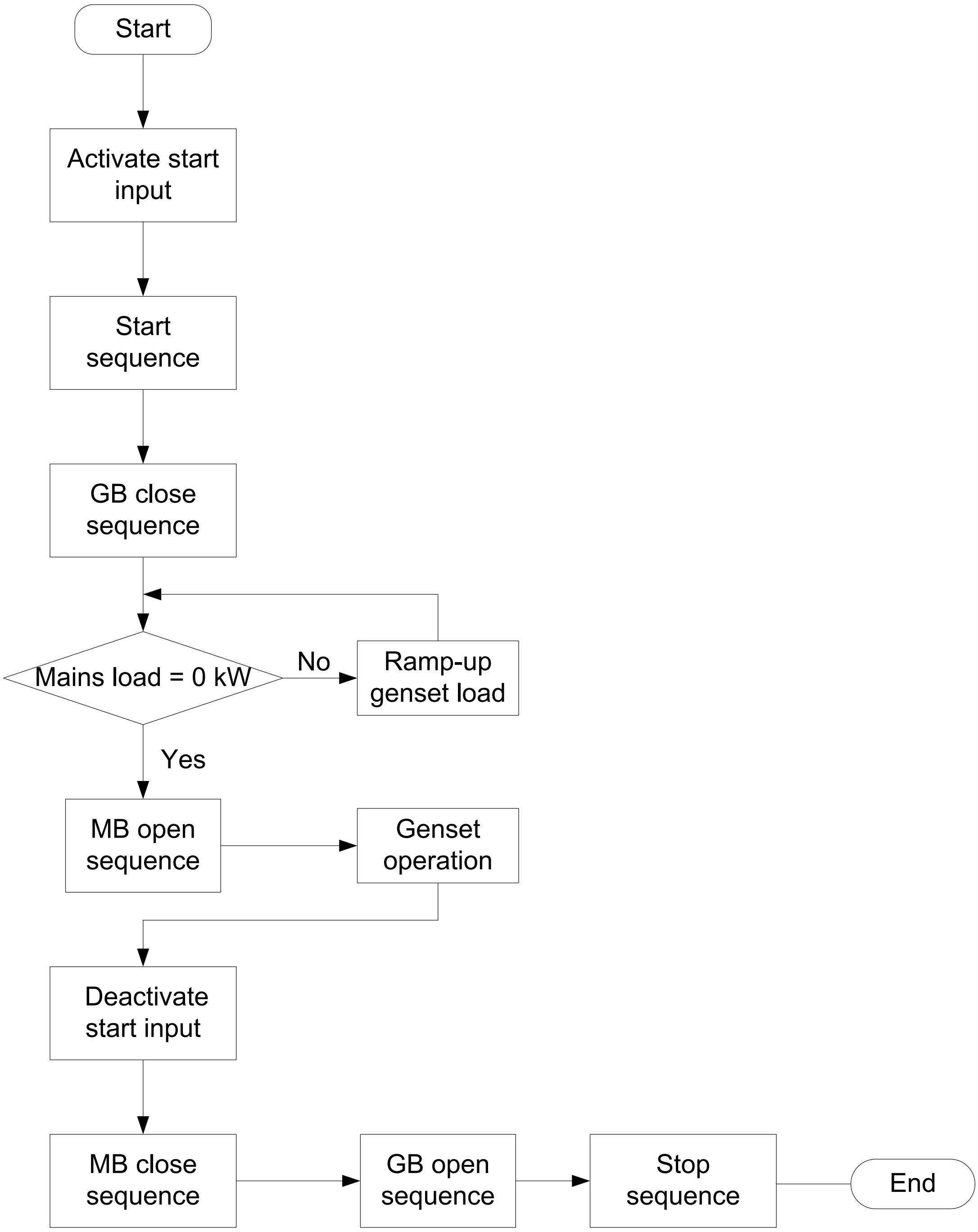
2.6.7 GB close sequence



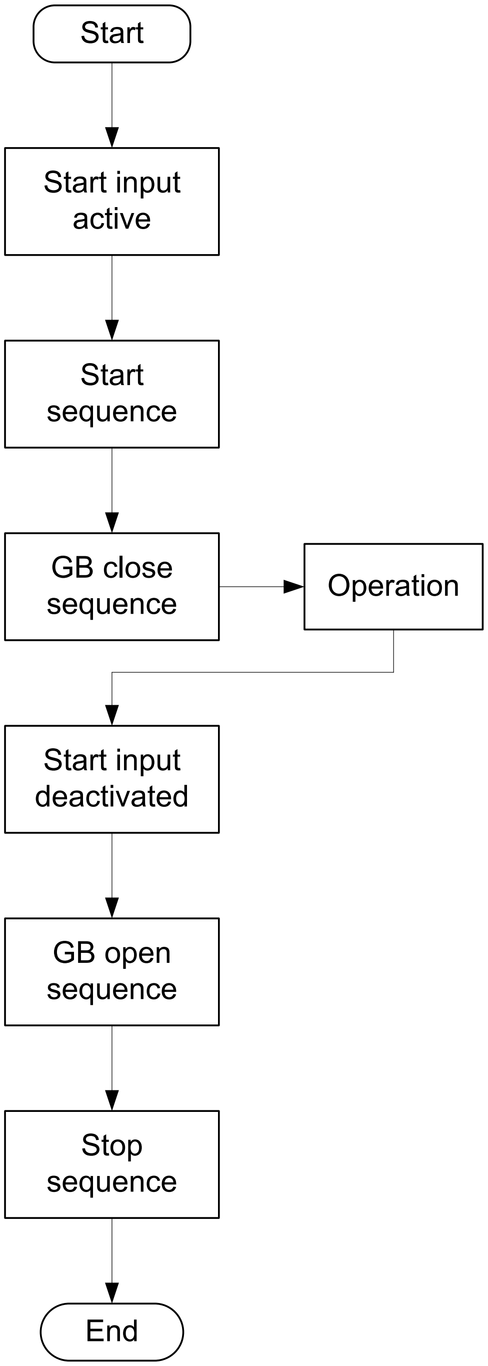
2.6.8 Fixed power



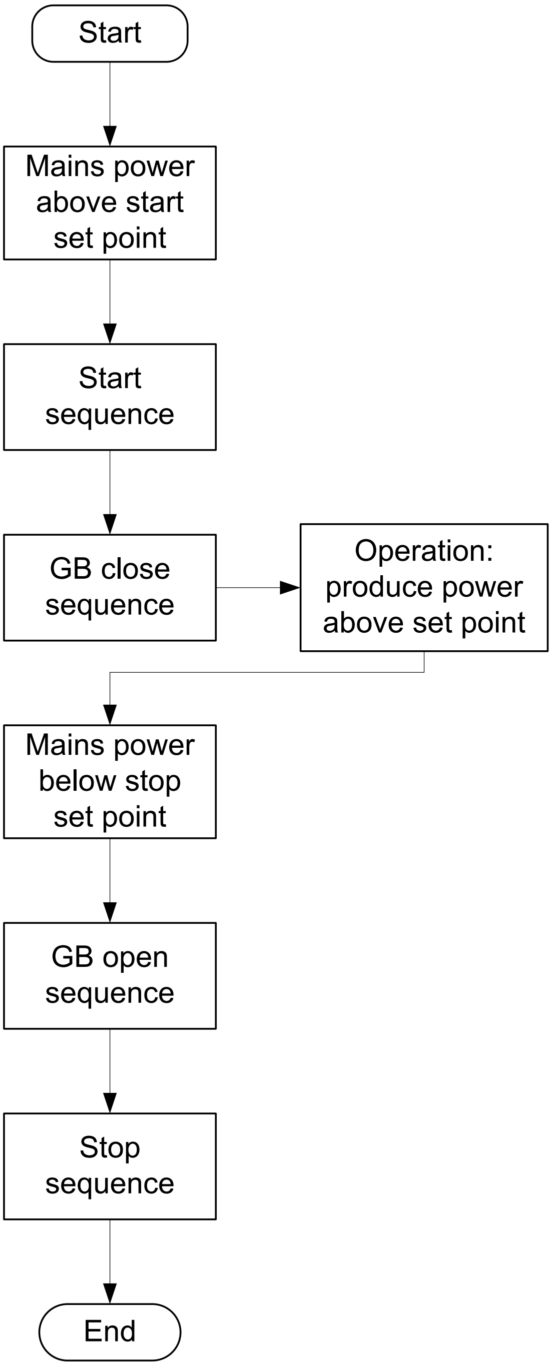
2.6.9 Load takeover



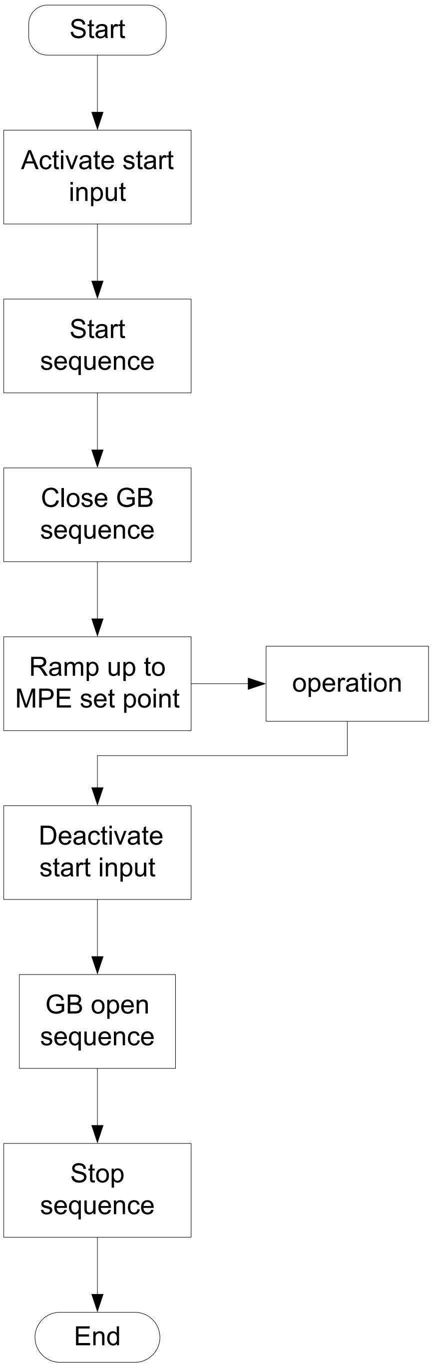
2.6.10 Island operation



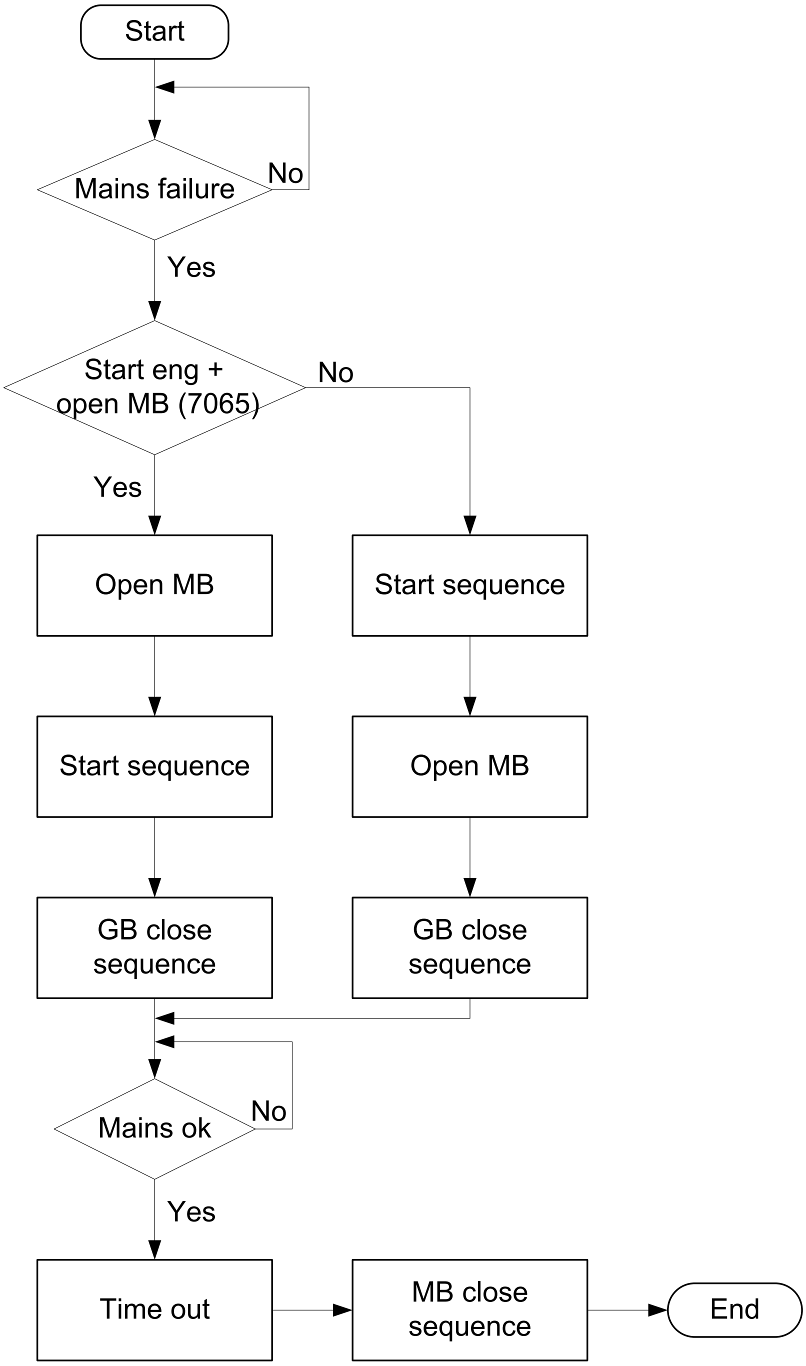
2.6.11 Peak shaving



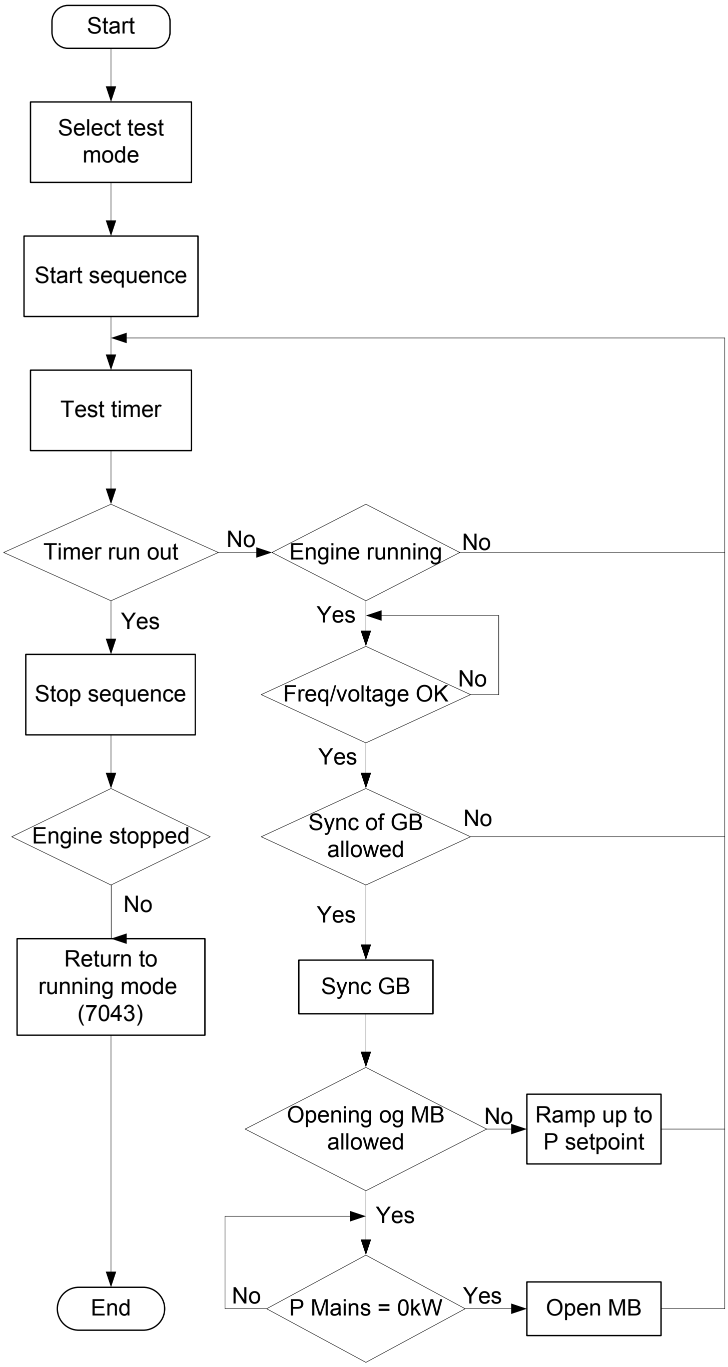
2.6.12 Mains power export



2.6.13 Automatic Mains Failure



2.6.14 Test sequence



2.7 Sequences

The following contains information about the sequences of the engine, the generator breaker and, if installed, the mains breaker. These sequences are automatically initiated if the auto mode is selected, or if the commands are selected in the semi-auto mode.

In the semi-auto mode, the selected sequence is the only sequence initiated (for example, press the START push-button: The engine will start, but no subsequent synchronising is initiated).

The following sequences will be illustrated below:

- START sequence
- STOP sequence
- Breaker sequences

If island operation is selected, the digital input *MB closed* must NOT be activated with a 12/24 volt input signal. A "mains breaker failure" will occur if the wiring of the mains breaker feedback inputs is wrong.

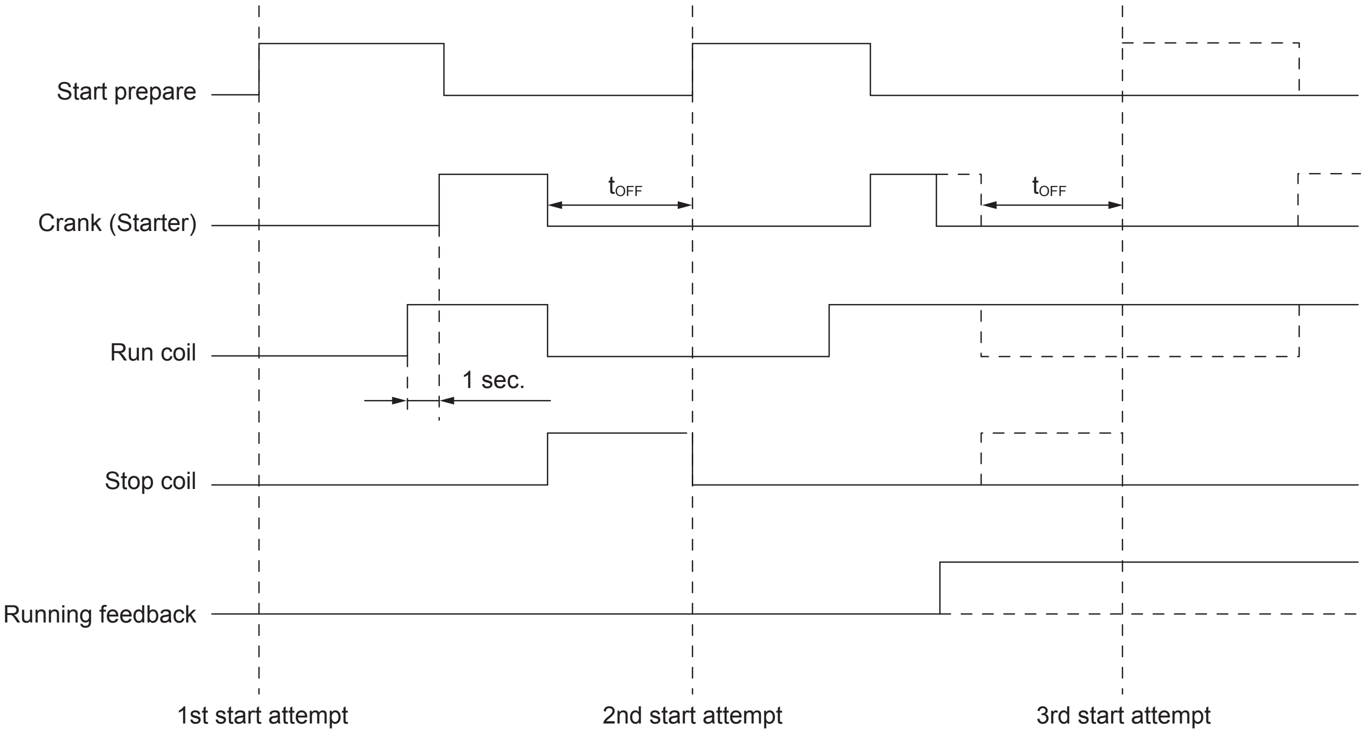
NOTE Refer to our application notes or installation instructions for information about the required breaker wiring.
NOTE We recommend not using small relays for stop coil output. If small relays are used, a resistor must be mounted across the relay coil to prevent undesirable closing of the relay. This is caused by the wirebreak function.

2.7.1 Start sequence

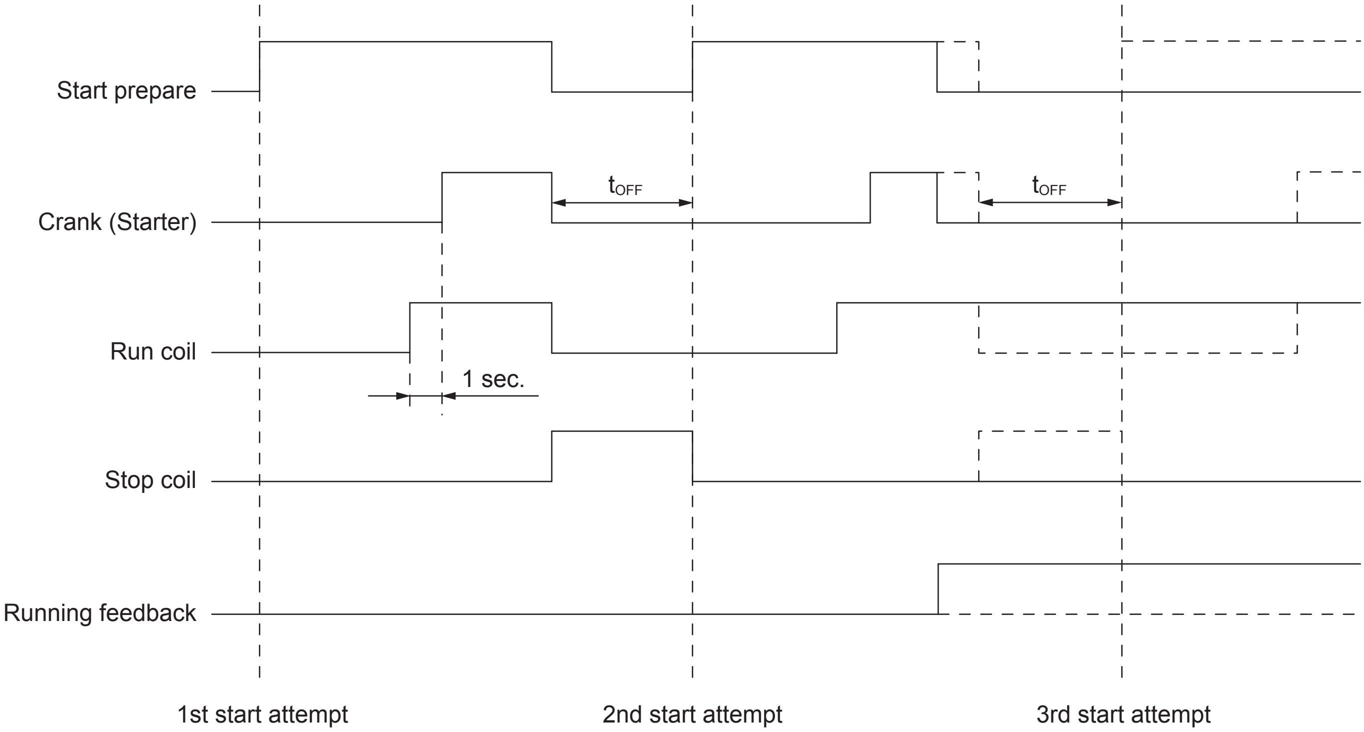
The following drawings show the start sequences of the genset with normal start prepare and extended start prepare.

No matter the choice of start prepare function, the running coil is activated 1 sec. before the start relay (starter).

Start sequence: Normal start prepare



Start sequence: Extended start prepare



NOTE The run coil can be activated from 1 to 600 sec. before the crank (starter) is activated. In the example above, the timer is set to 1 sec. (menu 6150).

2.7.2 Start sequence conditions

The start sequence initiation can be controlled by the following conditions:

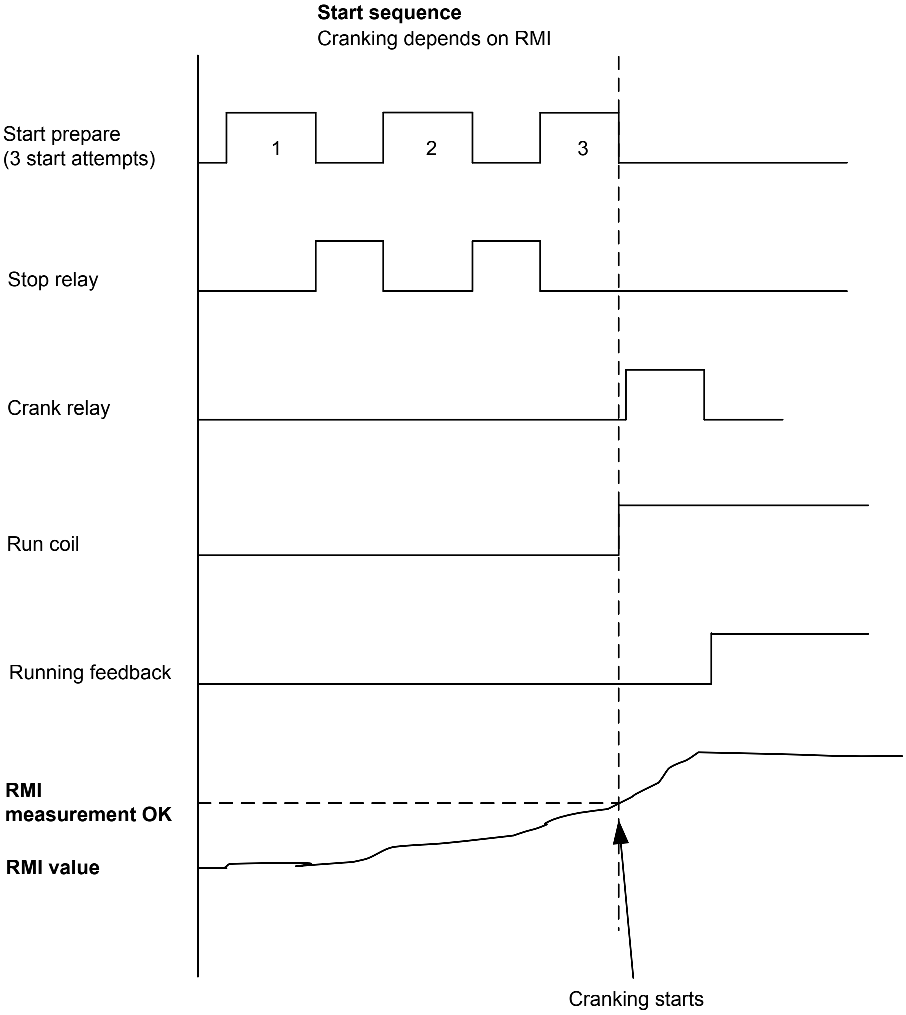
- Multi-input 102
- Multi-input 105
- Multi-input 108

This means that if, for example, the oil pressure is not primed to the sufficient value, the crank relay will not engage the starter motor.

The selection is made in setting 6185. For each of the RMI settings, the rule is that the value (oil pressure, fuel level or water temperature) must exceed the set point of setting 6186 before starting is initiated. If the value in 6186 is set to 0.0, the start sequence is initiated as soon as it is requested.

The diagram below shows an example where the RMI signal builds up slowly and starting is initiated at the end of the third start attempt.

Start sequence: Cranking depends on RMI



2.7.3 Running feedback

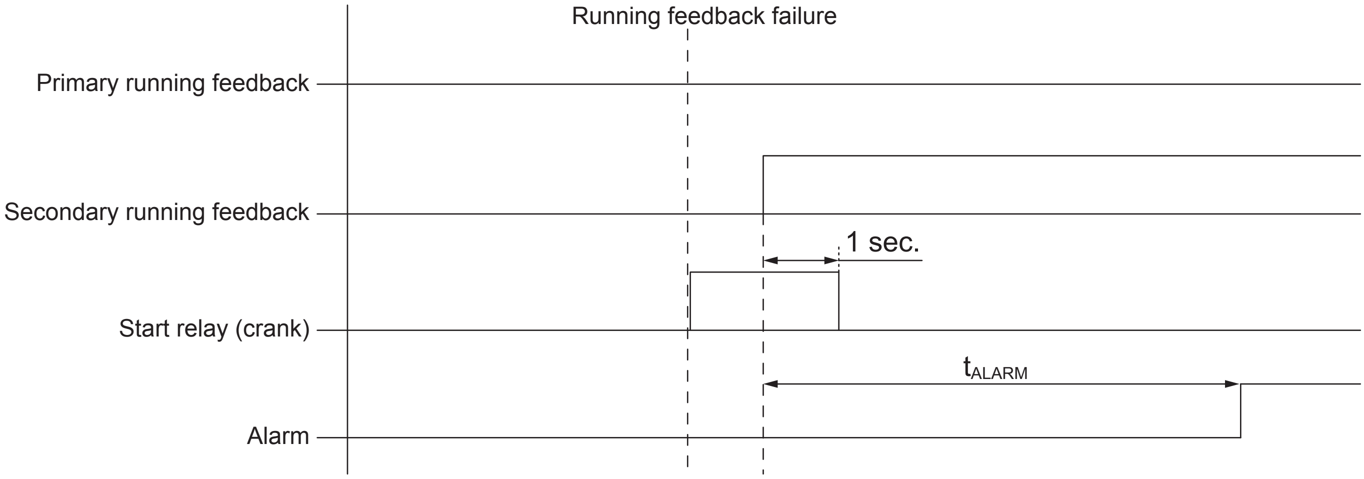
Different types of running feedback can be used to detect if the motor is running. Refer to menu 6170 for selection of the running feedback type.

The running detection is made with a built-in safety routine. The running feedback selected is the primary feedback. All configured running feedbacks are used at all times. If, for some reason, the primary choice is not detecting any running feedback, the starter relay will stay activated for one additional second. If a running feedback is detected based on one of the secondary choices, the genset will start. This way, the genset will still be functional even though a tacho sensor is damaged or dirty.

As soon as the genset is running, no matter if the genset is started based on the primary or secondary feedback, the running detection will be made based on all available types.

The sequence is shown in the diagram below.

Running feedback failure



Interruption of start sequence

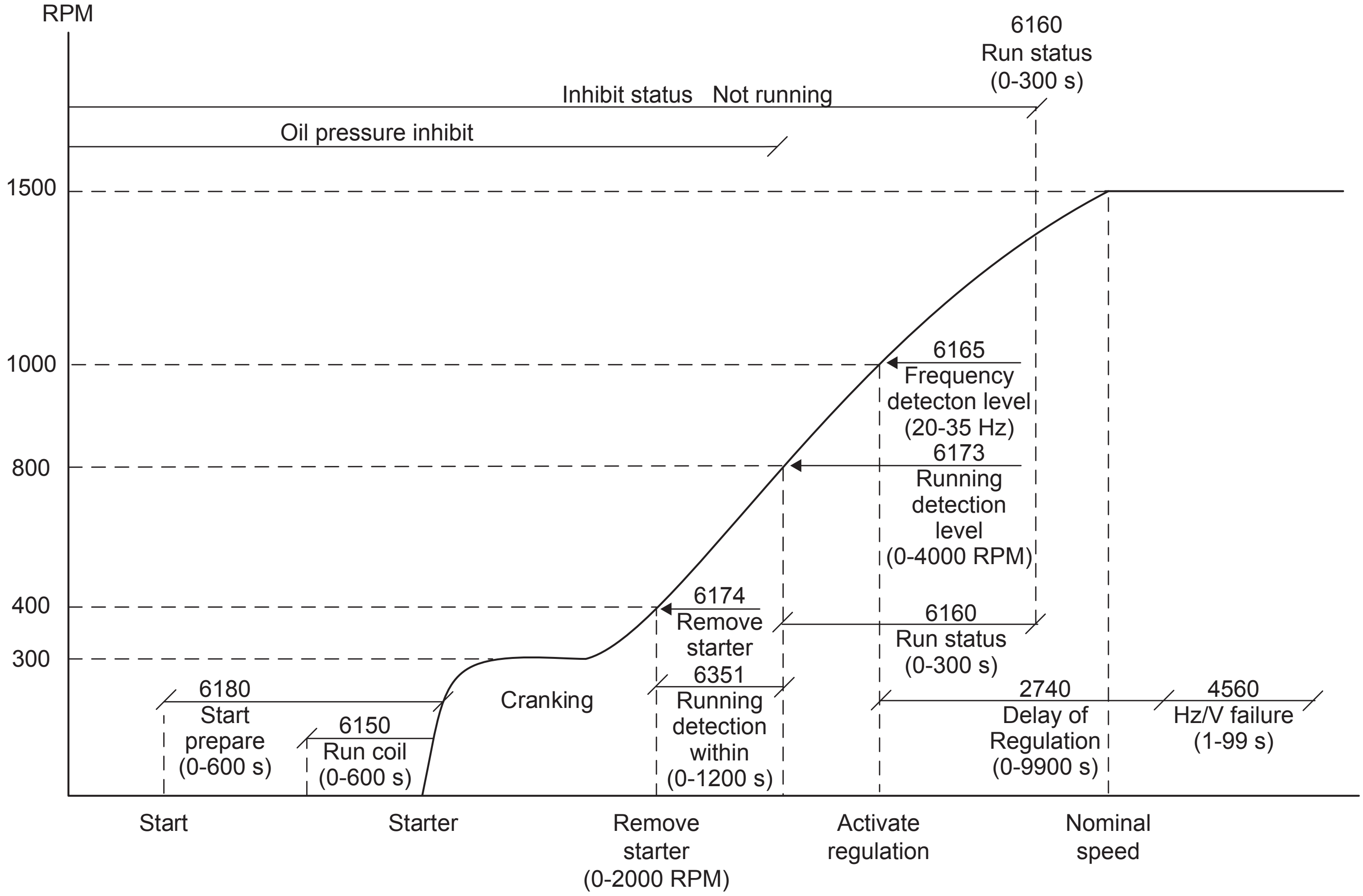
The start sequence is interrupted in the following situations:

Event	Comment
Stop signal	
Start failure	
Remove starter feedback	Tacho set point.
Running feedback	Digital input.
Running feedback	Tacho set point.
Running feedback	Frequency measurement above 32 Hz. The frequency measurement requires a voltage measurement of 30 % of U_{NOM}. The running detection based on the frequency measurement can replace the running feedback based on tacho or digital input or engine communication.
Running feedback	Oil pressure set point (menu 6175).
Running feedback	EIC (engine communication) (option H12).
Emergency stop	
Alarm	Alarms with *shutdown* or *trip and stop* fail class.
Stop push-button on display	Only in semi-auto or manual mode.
Modbus stop command	Semi-auto or manual mode.
Binary stop input	Semi-auto or manual mode.
Deactivate the "auto start/stop"	Auto mode in the following genset modes: Island operation, fixed power, load takeover or mains power export mode.
Running mode	Activating *BLOCK* while running will work in the same way as pushing the emergency stop, but it will also prevent the genset from starting afterwards.

NOTE If the MPU input is to be used to remove the starter, it must be set up in menu 6174.

NOTE The only protections that can stop the genset/interrupt the start sequence when the *shutdown override* input is activated, are the digital input *emergency stop* (menu 3490), the alarm *overspeed 2* (menu 4520) and the alarm *EIC RPM overspeed* (menu 7600). All must have the fail class *shut down*.

2.7.4 Start-up overview



Set points related to the start sequence

Start prepare	
6180 Starter	Normal prepare: The start prepare timer can be used for start preparation purposes, for example pre-lubrication or pre-glowing. The start prepare relay is activated when the start sequence is initiated and deactivated when the start relay is activated. If the timer is set to 0.0 s, the start prepare function is deactivated. Extended prepare: The extended prepare will activate the start prepare relay when the start sequence is initiated and keep it activated when the start relay activates, until the specified time has expired. If the extended prepare time exceeds the start ON time, the start prepare relay is deactivated when the start relay deactivates. If the timer is set to 0.0 s, the extended prepare function is deactivated. Start ON time: The starter will be activated for this period when cranking. Start OFF time: The pause between two start attempts.

Run coil timer	
6150 Run coil	The timer for the run coil is a set point that sets how long time the run coil will be activated before cranking the engine. This gives the ECU time to start up before cranking.

Remove starter	
6174 Remove starter	The starter is removed when the RPM set point is reached. This will only work, if MPU or EIC RPM is selected in **6172 Run detect type**.

Running detection RPM level	
6173 Running detection level	This is the set point where the running detection level is defined in RPM. This will only work, if MPU or EIC RPM is selected in **6172 Run detect type**.

Running detection	
6151 Running detection	This timer can be set to the needed level. This will make sure that the engine goes from the RPM level set in **6174 Remove starter** and **6173 Running detection level**. If the timer is exceeded and the level is not reached, the start sequence will start over and will have used a start attempt. If all start attempts (**6190 Start attemps**) are used, the **4570 Start failure** will occur. This timer will only be active, if MPU or EIC RPM is selected in **6172 Run detect type**. **NOTE** If other running detection types than MPU or EIC RPM are used, the starter will be on until **6165 Frequency detection level** is reached.

Frequency level	
6165 Frequency detection level	This set point is in Hz and can be set to the needed level. When the level is reached, the regulators will start working and make sure to reach the nominal values. The regulators can be delayed using **2740 Delay of regulation**. See below.

Run status	
6160 Run status	The timer in this set point is started when **6173 Running detection level** is reached, or when **6165 Frequency detection level** is reached. When the timer is exceeded, the inhibit status Not running will be deactivated, and the running alarms and failures will be enabled (see the related failures below).

Delay of regulation	
2740 Delay of regulation	By using this timer, the regulation start can be delayed. The timer will start when **6165 Frequency detection level** is reached. **NOTE** If the setup is running on nominal settings and **2740 Delay of regulation** is set to 0, the genset will overshoot the nominal frequency on start-up, as the regulators start increasing as soon as they are turned on. If this timer is used, the regulation can wait until the genset is already at nominal frequency before starting to regulate.

Failures related to the start sequence

Crank failure alarm	
4530 Crank failure	If MPU is chosen as the primary running feedback, this alarm will be raised if the specified RPM is not reached before the delay has expired.

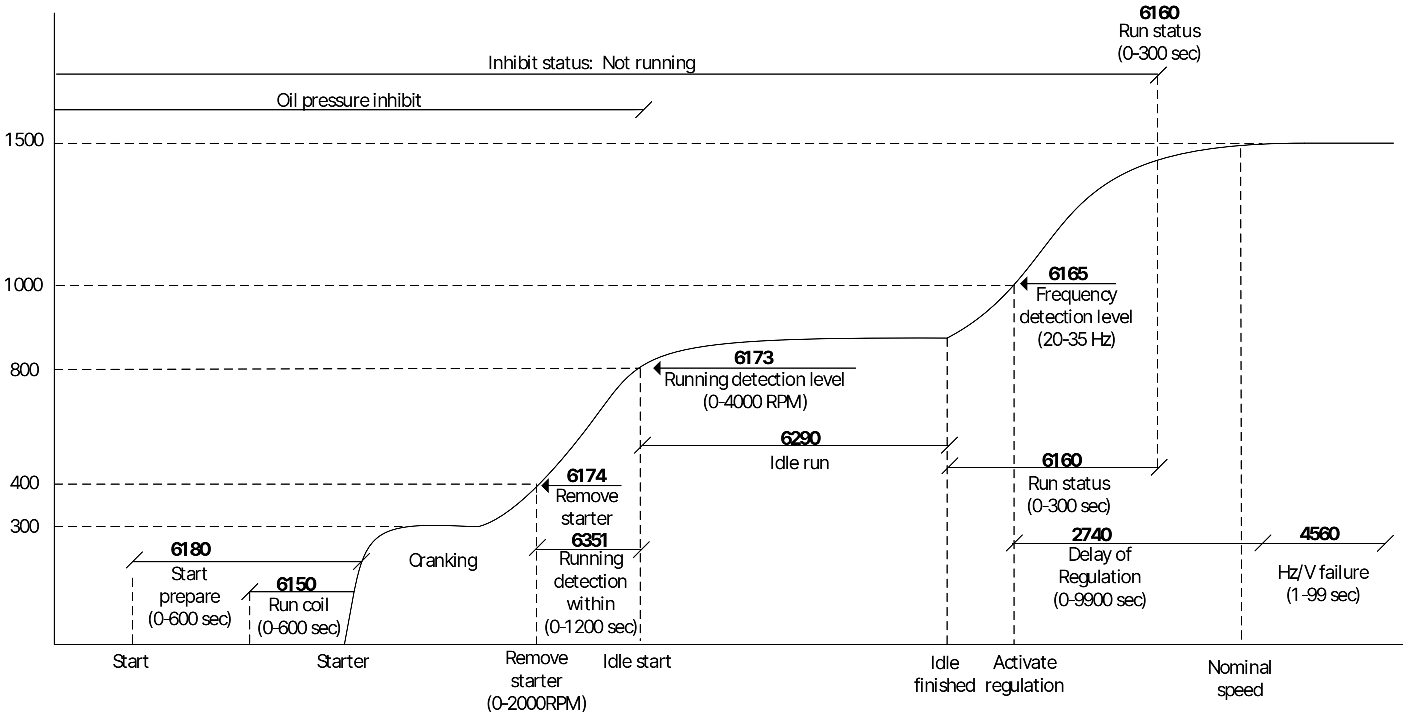
Run feedback failure	
4540 Run feedb. fail	This is an alarm, in case there is no primary running feedback (6172), but the secondary feedback detects running. There is a failure on the primary running feedback, and therefore this alarm will be raised with a delay. The delay to be set is the time from the secondary running detection and until the alarm is raised.

Hz/V failure	
4560 Hz/V failure	If the frequency and voltage are not within the limits set in **2110 Blackout df/dUmax** after the running feedback is received, this alarm is raised when the delay has expired.

Start failure alarm	
4570 Start failure	The start failure alarm occurs, if the genset has not started after the number of start attempts set in menu 6190.

Engine externally stopped	
6352 Ext. Eng. Stop	If running sequence is active and the engine goes below **6173 Running detection** and **6165 Frequency detection level** without any command from the AGC, it will set an alarm if this parameter is enabled.

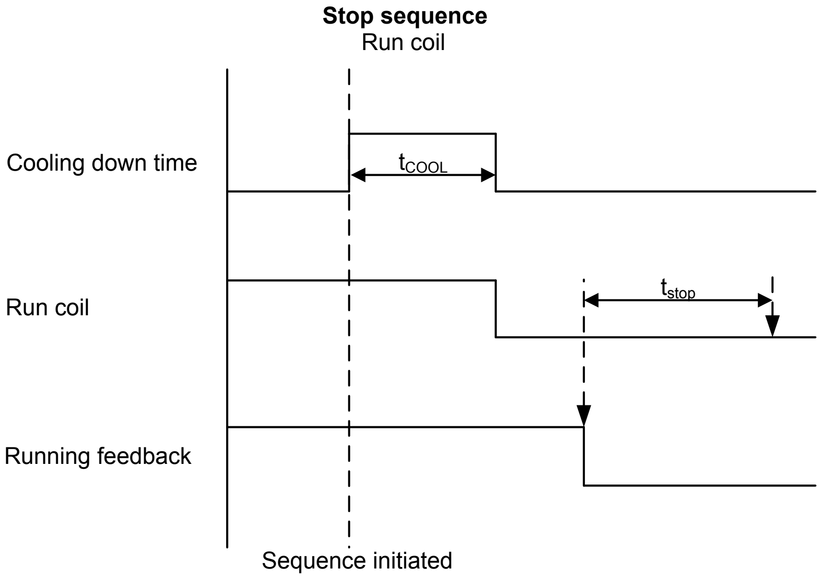
2.7.5 Start-up overview with idle run

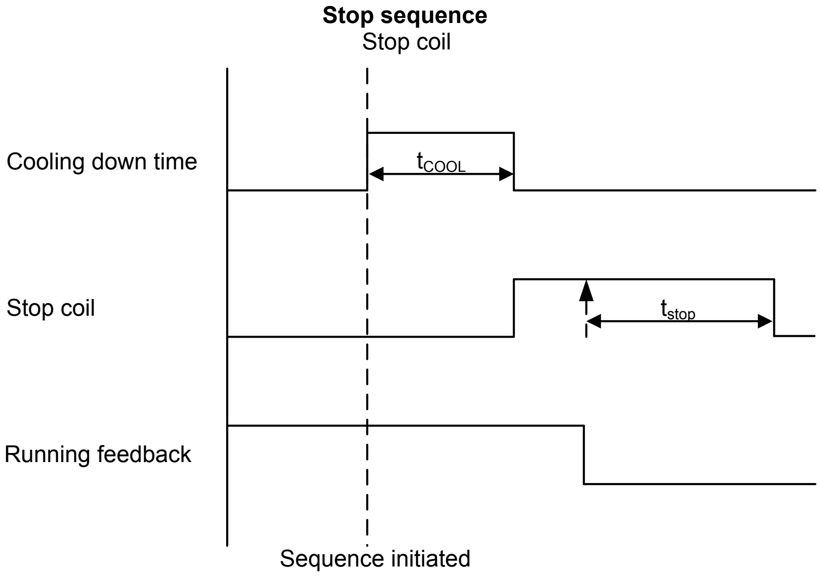


The set points and failures in this overview are the same as described in the chapter "Start-up overview", except for the idle run function. This function is described in the chapter "Idle running".

2.7.6 Stop sequence

The drawings show the stop sequence.





The stop sequence is activated if a stop command is given. The stop sequence includes the cooling down time if the stop is a normal or controlled stop.

Description	Cooling down	Stop	Comment
Auto mode stop	●	●	
Trip and stop alarm	●	●	
Stop button on display	●*	●	Semi-auto or manual. Cooling down is interrupted if the stop button is activated twice.
Remove "auto start/stop"	●	●	Auto mode: Island operation, fixed power, load takeover, mains power export.
Emergency stop		●	Engine shuts down and GB opens.

* The stop sequence can only be interrupted during the cooling down period. Interruptions can occur in these situations:

Event	Comment
Mains failure	AMF mode selected (or mode shift selected ON) and auto mode selected.
Start button is pressed	Semi-auto mode: Engine will run in idle speed.
Binary start input	Auto mode: Island operation and fixed power, load takeover or mains power export.
Exceeding set point	Auto mode: Peak shaving.
GB close button is pressed	Semi-auto mode only.

NOTE The stop sequence can only be interrupted during the cooling down period.
NOTE When the engine is stopped, the analogue speed governor output is reset to the offset value.

Set points related to the stop sequence

Stop failure	
4580 Stop failure	A stop failure alarm will appear if the primary running feedback or the generator voltage and frequency are still present after the delay in this menu has expired.

Stop	
6210 Stop	Cooling down: The length of the cooling down period. Extended stop: The delay after the running feedback has disappeared until a new start sequence is allowed. The extended stop sequence is activated any time the Stop button is pressed. Cool down controlled by engine temperature: The engine temperature-controlled cool down is to ensure that the engine is cooled down below the set point in menu 6214 *Cool down temperature* before the engine is stopped. This is particularly beneficial if the engine has been running for a short period of time and therefore not reached normal cooling water temperature, as the cool down period will be very short or none at all. If the engine has been running for a long period, it will have reached normal running temperature, and the cool down period will be the exact time it takes to get the temperature below the temperature set point in menu 6214.

If, for some reason, the engine cannot get the temperature below the temperature set point in 6214 within the time limit in parameter 6211, the engine will be shut down by this timer. The reason for this could be high ambient temperature.

NOTE If the cooling down timer is set to 0.0 s, the cooling down sequence will be infinite.
NOTE If the cooling down temperature is set to 0 deg., the cooling down sequence will be entirely controlled by the timer.
NOTE If the engine stops unexpectedly, see **Running feedback**.

2.7.7 Breaker sequences

The breaker sequences will be activated depending on the selected mode:

Mode	Genset mode	Breaker control
Auto	All	Controlled by the controller
Semi-auto	All	Push-button
Manual	All	Push-button
Block	All	None

Before closing the breakers it must be checked that the voltage and frequency are OK. The limits are adjusted in menu 2110 Sync. blackout.

Set points related to MB control

7080 MB control	
Mode shift	When enabled, the AGC will perform the AMF sequence in case of a mains failure regardless of the actual genset mode.
MB close delay	The time from GB OFF to MB ON when back synchronisation is OFF.
Back sync.	Enables synchronisation from mains to generator.
Sync. to mains	Enables synchronisation from generator to mains.
Load time	After opening of the breaker, the MB ON sequence will not be initiated before this delay has expired. Please refer to the description of "Breaker spring load time".

NOTE If no MB is represented, then the relays and inputs normally used for MB control become configurable. The power plant constructor (USW) is used for configuration of the plant design if the application does not include an MB.

NOTE AGC without back synchronisation: The GB can only be closed if the mains breaker is open. The MB can only be closed if the generator breaker is open.

NOTE AGC with back synchronisation: If the GB or MB push-button is activated, the AGC will start synchronising if the generator or mains voltage is present. The GB can close directly if the MB is open. The MB can close directly if the GB is open.

AMF MB opening (menu 7065)

It is possible to select the functionality of the mains breaker opening function. This is necessary if the controller operates in Automatic Mains Failure (AMF).

The possibilities in menu 7065 are:

Selection	Description
Start engine + open mains breaker	When a mains failure occurs, the mains breaker opens, and the engine starts at the same time.
Start engine	When a mains failure occurs, the engine starts. When the generator is running and the frequency and voltage are OK, the MB opens and the GB closes.

2.7.8 AMF timers and set points

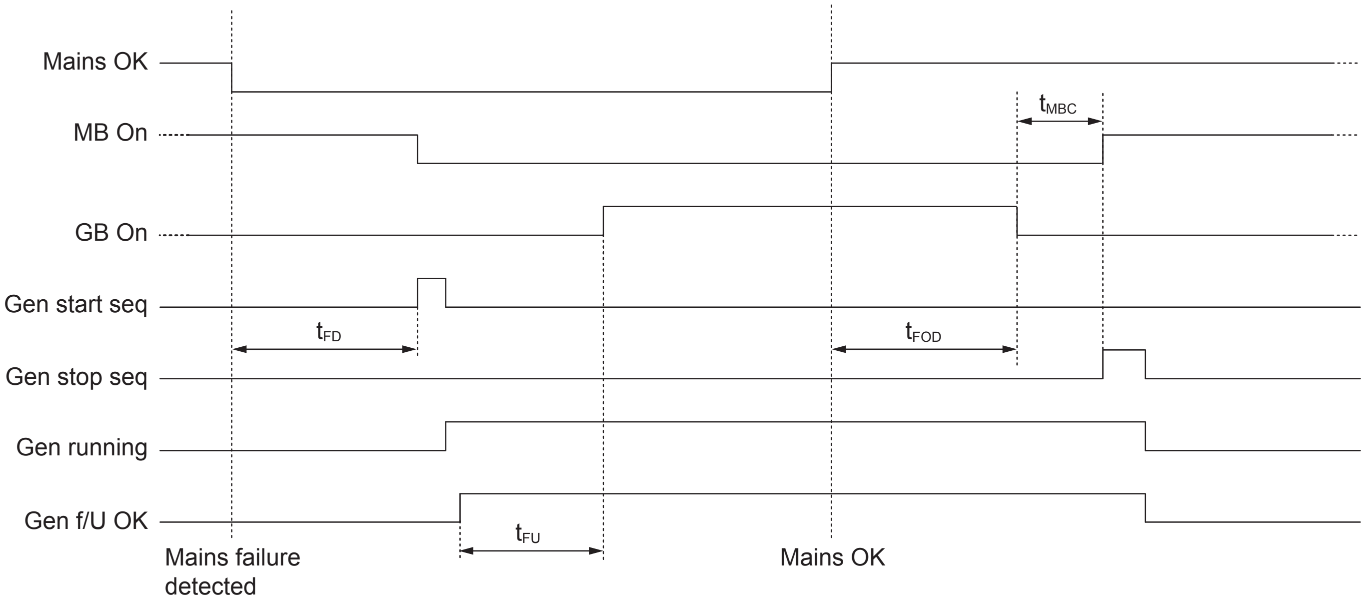
The time charts describe the function at a mains failure and at mains return. Back synchronisation is deactivated. The timers used by the AMF function are shown in the table below:

Timer	Description	Menu number
t_{FD}	Mains failure delay	7071 f mains failure 7061 U mains failure
t_{FU}	Frequency/voltage OK	6220 Hz/V OK
t_{FOD}	Mains failure OK delay	7072 f mains failure 7062 U mains failure
t_{GBC}	GB ON delay	6231 GB control*
t_{MBC}	MB ON delay	7082 MB control

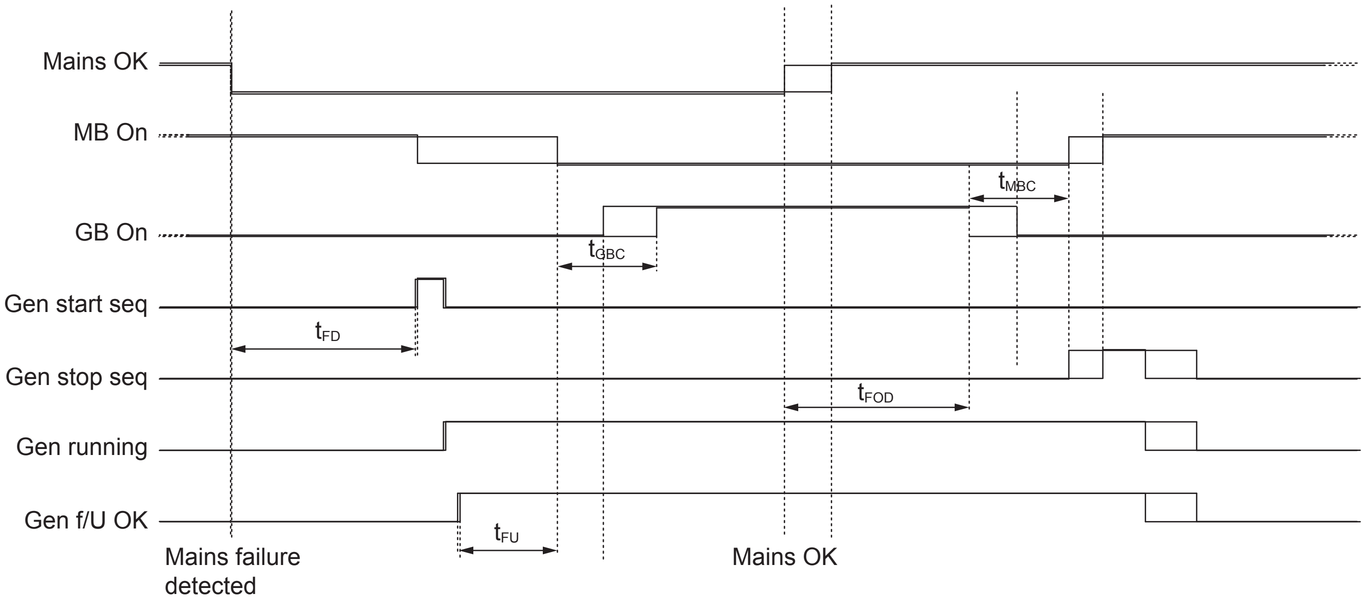
*Note: Only for a genset controller in a *Single DG* application. If there is a blackout, this is the close delay after the voltage and frequency are okay.

The timer t_{MBC} is only active if back synchronisation is deactivated.

Example 1: 7065 Mains fail control: Start engine and open MB



Example 2: 7065 Mains fail control: Start engine



Set points for the AMF sequence

The timers must have some set points to indicate when they are to start. The AGC has different set points for the different situations. The limits that the mains voltage must be within before the failure timer starts, are set in parameters 7063 and 7064. There is a low (7063) and a high (7064) limit. Furthermore, the AGC has limits for the frequency. This also has a low limit (7073) and a high limit (7074). If the mains voltage or frequency has exceeded one of these limits and the relevant fail timer has expired, the AMF sequence will be started.

When the mains voltage/frequency has returned, some hystereses can be adjusted. The Multi-line 2 controller has four separate hystereses which are located in menu 7090. The first hysteresis is for the “low voltage limit”. If the mains “low voltage” is set at 90 % (7063), the Multi-line 2 will start the “Automatic Mains Failure” sequence when the voltage is lower than 90 % of the nominal voltage. By default, the hysteresis is set at 0 % (7091), which means, in this example, that when the voltage has increased above 90 %, it is allowed to feed the load from the grid again. If the hysteresis had been set at 2 %, it would not be allowed to go back to grid until the mains voltage had increased above 92 %.

If, for example, the “mains low voltage” was set at 85 % and the hysteresis was set at 20 %, the calculation would imply that it was not allowed to go back to grid operation until the mains voltage was 105 %. The Multi-line 2 controller can be 100 % of nominal at the most. This is the same for “mains high voltage” and both frequency limits. The hysteresis can be at 100 % nominal at the most.

Conditions for breaker operations

The breaker sequences react depending on the breaker positions and the frequency/voltage measurements.

The conditions for the ON and OFF sequences are described in the tables below.

Breaker close conditions

Sequence	Condition
GB ON, direct closing	Running feedback Generator frequency/voltage OK MB open
MB ON, direct closing	Mains frequency/voltage OK GB open
GB ON, synchronising	Running feedback Generator frequency/voltage OK MB closed No generator failure alarms
MB ON, synchronising	Mains frequency/voltage OK GB closed No generator failure alarms

Breaker open conditions

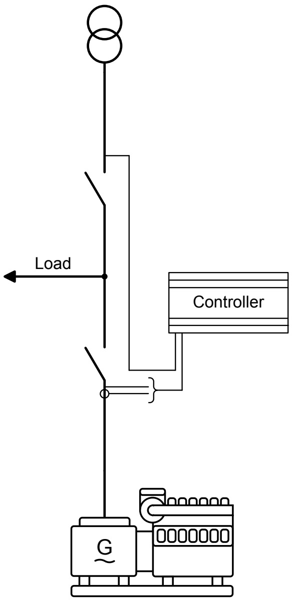
Sequence	Condition
GB OFF, direct opening	MB open
MB OFF, direct opening	Alarms with fail classes: Shut down or Trip MB alarms
GB OFF, deloading	MB closed
MB OFF, deloading	Alarms with fail class: Trip and stop

3. Applications without power management

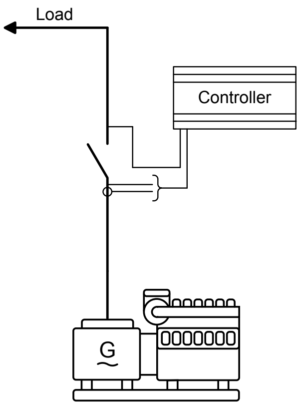
3.1 Single-line diagrams

The following single-line diagrams show a variety of AGC applications. These applications do not require power management (option G5).

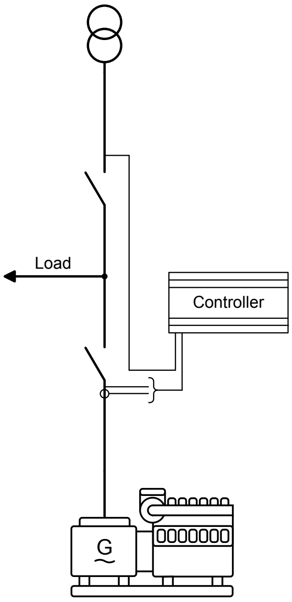
3.1.1 Automatic Mains Failure



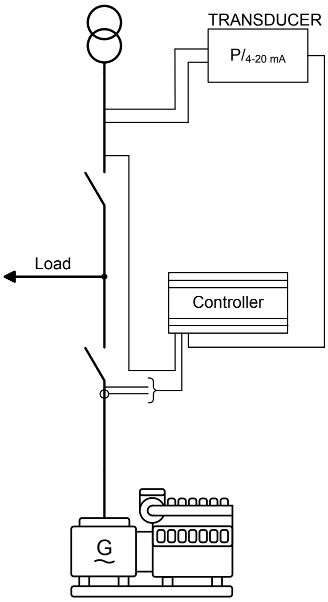
3.1.2 Island operation



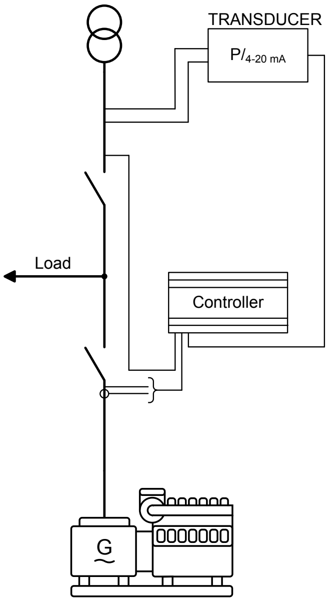
3.1.3 Fixed power/base load



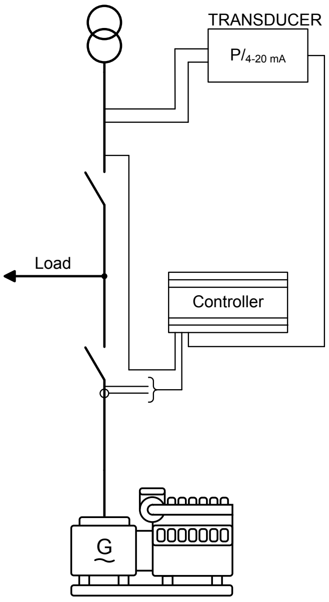
3.1.4 Peak shaving



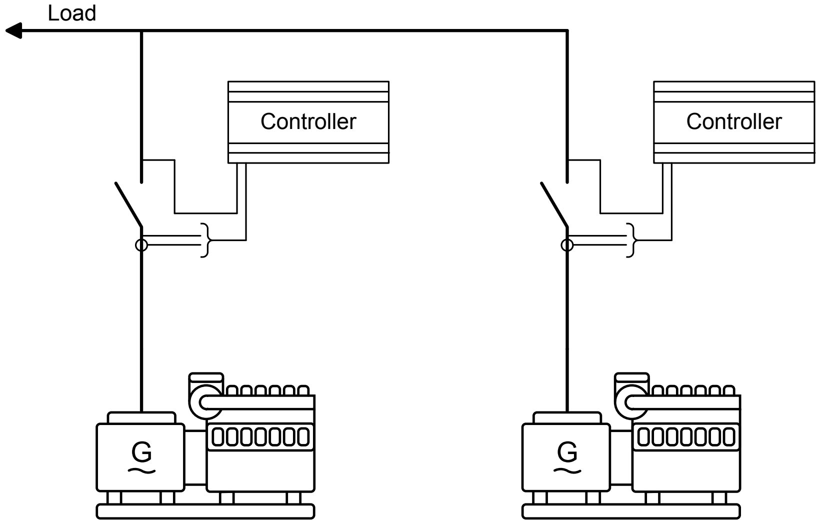
3.1.5 Load takeover



3.1.6 Mains power export



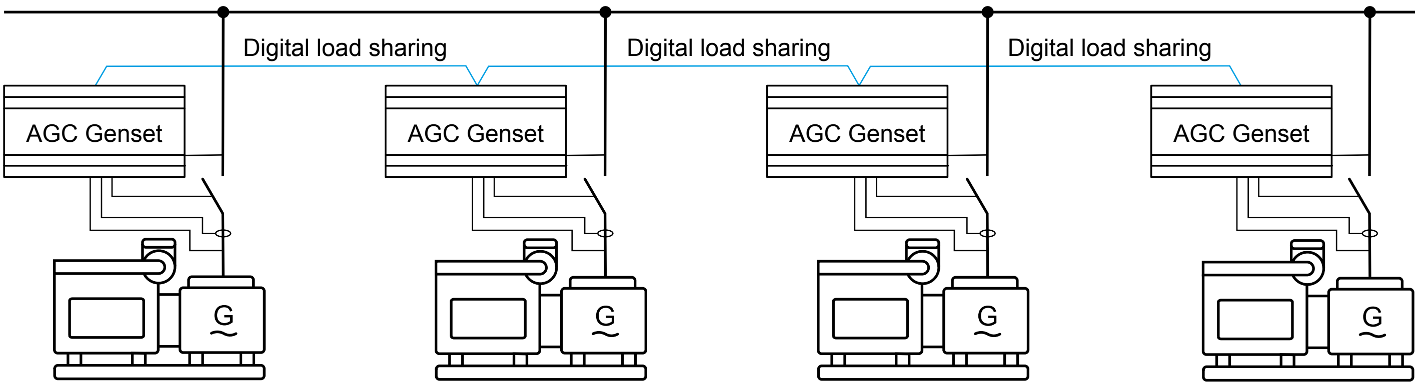
3.1.7 Multiple gensets, load sharing (hardware option M12 required)



3.2 CANshare

3.2.1 Single-line diagram

Multiple single gensets, with CANshare digital load sharing



CANshare (digital load sharing) makes it possible to for generators to load share using CAN bus, with simple installation and setup. CANshare load sharing is equal (as a percentage of each generator's nominal power). CANshare ensures that both active power (P) and reactive power (Q) are shared.

You can use CANshare in applications with 2 to 127 generators. For CANshare, you can have a mix of AGC-4 Mk II and AGC 150 generator controllers.

CANshare cannot be used with power management. CANshare cannot be used with mains connections.

3.2.2 Configure CANshare (digital load sharing)

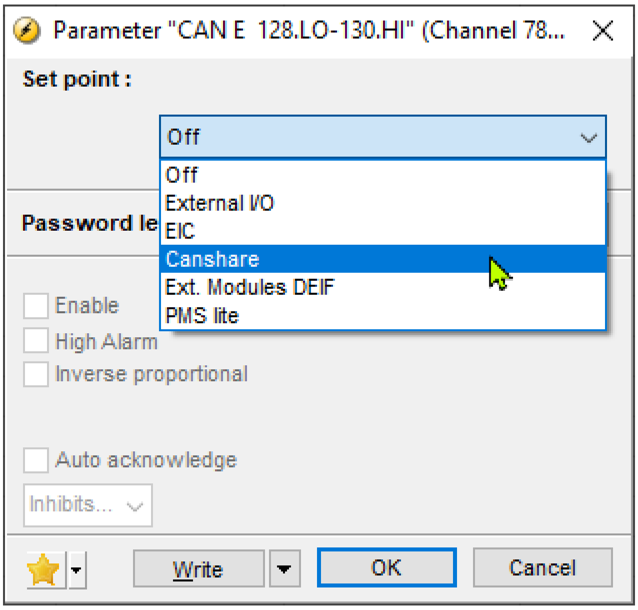
Set up the CAN protocol and the application **in each controller**. You can use the utility software, or you can set parameters from the display.

Set the CAN protocol from the utility software or the display

1. Select the CAN protocol that corresponds to the CAN terminals that you will use for CANshare:
   - Parameter 7843 for CAN protocol C
   - Parameter 7844 for CAN protocol D
   - Parameter 7845 for CAN protocol E
   - Parameter 7846 for CAN protocol F

NOTE You do not need to use the same CAN protocol in each controller.

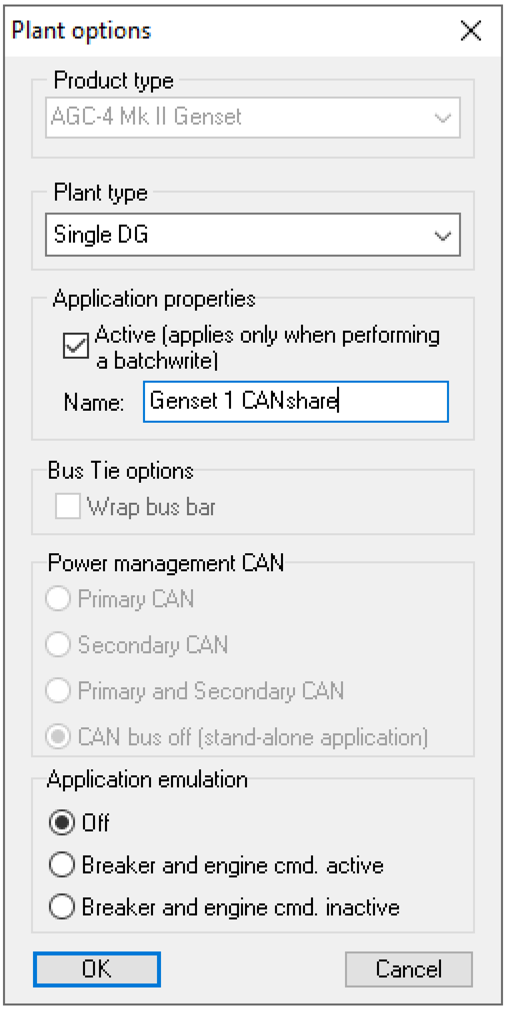
2. For the set point, select *Canshare*:



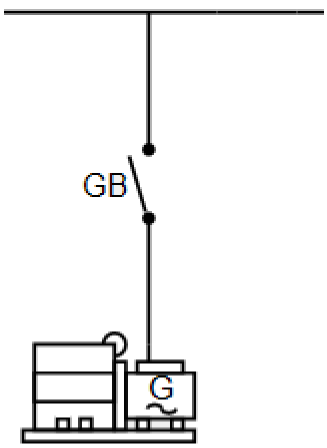
More information
See **CANshare (option H12.2/H12.9)** in the **Installation instructions** for how to wire the CAN terminals.

Using the utility software to set up the application

1. Create a new plant configuration. For *Plant type*, select *Single DG*:



2. When you select Single DG, the utility software shows an application drawing with a single generator*. You can select the generator breaker type here.



3. Write the application configuration to the controller:

   NOTE * For CANshare, the source must only be a genset. Do not select mains as a source too.

Using display* parameters to set up the application

To set up the application for CANshare, configure the following parameters:

Parameter	Name	Range	Default	Details
9181	9180 Quick Setup	Off Setup stand alone	Off	Select **Setup stand alone**.

Parameter	Name	Range	Default	Details
		Setup plant		
9182	9180 Quick Setup	Off CAN PM Primary CAN PM Secondary CAN PM PRI + SEC	Off	Select **Off**.
9183	9180 Quick Setup	Pulse No MB Continuous Compact	No MB	Select **No MB**.
9184	9180 Quick Setup	Pulse Continuous Compact	Pulse	Select the generator breaker type.
9185	9180 Quick Setup	Mains present No mains present	No mains present	Select **No mains present**.
9186	9180 Quick Setup	SingleDG Standard	SingleDG	Select **SingleDG**.

NOTE * For a DU-2, jump to menu 9180.

How it works

The system is now ready for CANshare (digital load sharing). More generators can be added to the CANshare line without having to assign CAN IDs. A CANshare controller can also disconnect from the CAN bus line.

3.2.3 CANshare in operation

When a controller is added to the CANshare line, it is automatically included in the load sharing. Similarly, when a controller is removed from the CANshare line, it is automatically removed from the load sharing.

There is no CANshare line supervision. That is, no alarm is activated if the CANshare line fails. Each set of controllers on either side of the failure operate independently. Within each set, the load is shared equally.

CANshare failure

Parameter	Name	Range	Default	Details
7860	CAN Share failu	0 to 100 s	0 s	If one of the CAN protocols is *CANshare*, but the controller cannot detect another CANshare controller on the CAN line, then the controller activates this alarm. You can use this alarm to troubleshoot the CANshare communication.
7866	CAN Sha fail mo	Manual Semi-auto No mode change	Manual	You can select whether to change the controller mode when the CANshare failure alarm is activated.

More information
See **Unsupported application** for the alarm that is activated if the controller detects a mixture of CANshare and PMS lite on the CAN line.

3.2.4 M-Logic CANshare flags

CANshare flags are available in M-Logic. You can use these for exchanging status and commands between the controllers connected to the CANshare line. You can activate any of the flags from any of the controllers. You can activate more than one flag from one controller.

NOTE For reliable operation, you must use continuous signals to activate the CAN flags.

M-Logic: `Output > CANshare Flags`

Description	Notes
CANshare Flag [1 to 128]	Activates CANshare flag [#] in every controller connected to the CANshare line.

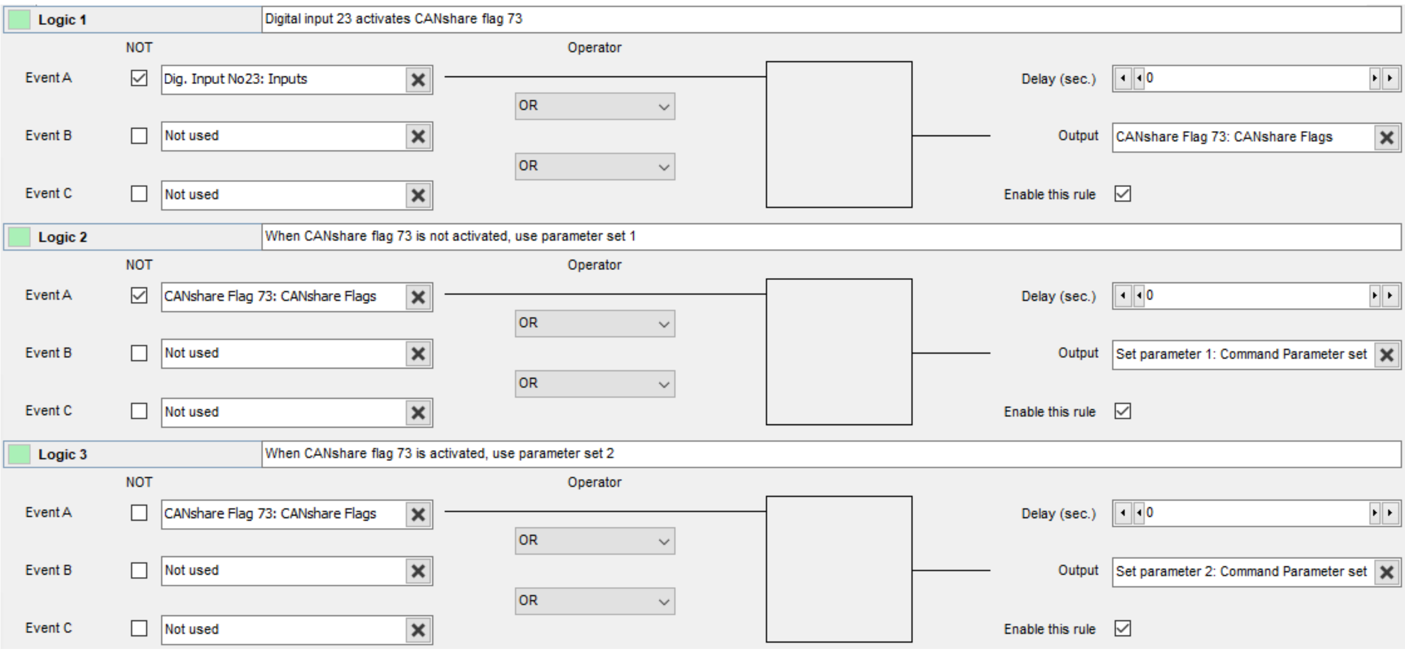
M-Logic: `Events > CANshare Flags`

Description	Notes
CANshare Flag [1 to 128]	CANshare flag [#] is activated in a controller connected to the CANshare line.

CANshare flag example

The operator wants to use a switch to change the nominal settings in all the CANshare controllers. When the switch is off, all controllers must use nominal settings 1. When the switch is on, all controllers must use nominal settings 2.

Create the following M-Logic in the controller where the switch is connected to digital input 23:

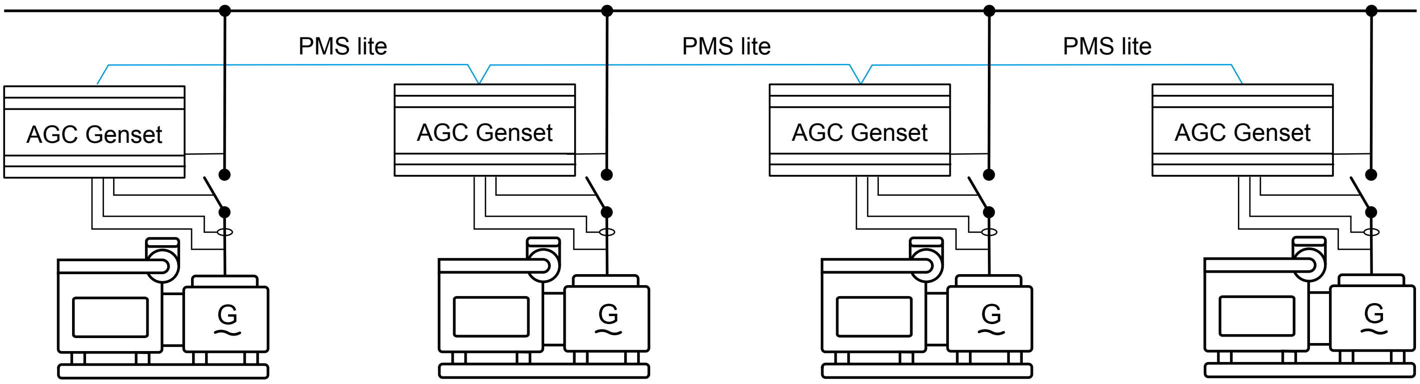


Create M-Logic lines 2 and 3 in each of the other controllers.

4. PMS lite

4.1 Single-line drawing

PMS lite, with up to 127 single gensets



4.2 PMS lite

PMS lite is for off-grid plants with up to 127 generators. PMS lite is only for generators - no other power sources are possible. Each controller protects and controls a genset, and the genset breaker. The operator can easily configure the plant from the display, without needing to use a PC with utility software.

PMS lite makes sure that generators are started or stopped according to the load and priority. PMS lite makes sure that the generators share the load equally. The plant set up is quick because the controllers use the CAN bus connections to automatically detect each other and assign IDs. To have the CAN bus connections required for PMS lite, each AGC-4 Mk II controller must have hardware option H12.2 or H12.8.

NOTE PMS lite can only be used in a system where all the controllers use PMS lite. For PMS lite, you can have a mix of AGC-4 Mk II and AGC 150 generator controllers. PMS lite cannot be used in a standard power management system.

PMS lite plant
Automatic detection and ID assignment • The operator can use the display to manually assign IDs
PMS lite settings • Different settings in each controller supported • Supports sharing the PMS lite configuration between controllers
Configurable baud rate for PMS lite communication (125/250 kbps)
PMS lite load sharing • Equal load sharing for active (P) and reactive (Q) power
Generator priority • Assigned automatically • Assigned manually (multiple controllers can have the same priority) • Based on running hours
Select the gensets to start (for example, after a blackout)
Start timer (suspend load-dependent start and stop while the timer runs)

Load-dependent start and stop (LDSS)
Automatically start the next generator for high load
Automatically stop the next generator for low load

Load-dependent start and stop (LDSS)
Manual start and stop available
Select the minimum number of running generators
PLC start-stop • Disable load-dependent start and stop • PLC controls start and stop using digital inputs, Modbus and/or M-Logic

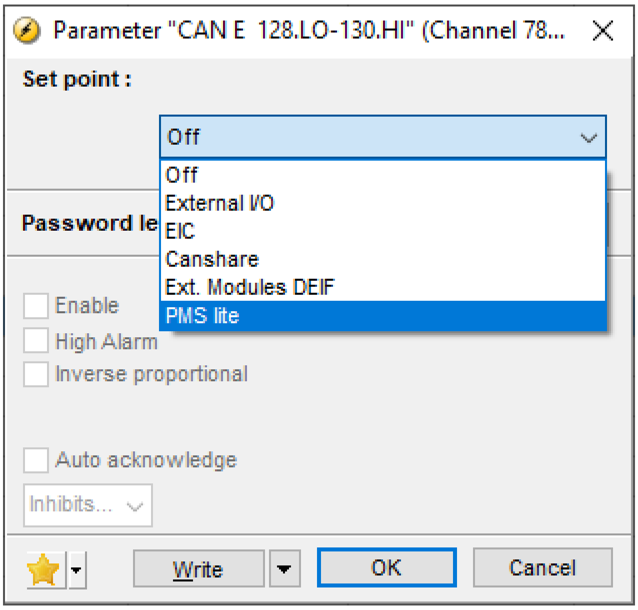
4.3 Set up PMS lite

Set up the CAN protocol and the application **in each controller**. You can set parameters from the display, or you can use the utility software.

Set the CAN protocol from the display or utility software

1. Select the CAN protocol that corresponds to the CAN terminals that you will use for PMS lite:
   - Parameter 7843 for CAN protocol C
   - Parameter 7844 for CAN protocol D
   - Parameter 7845 for CAN protocol E
   - Parameter 7846 for CAN protocol F

   NOTE You do not need to use the same CAN protocol in each PMS lite controller.
   NOTE You cannot have other types of CAN bus communication (for example, CANshare, EIC, DVC, or CIO) on the PMS lite CAN line.
2. For the set point, select *PMS lite*:



More information
See **PMS lite (option H12.2/H12.8)** in the **Installation instructions** for how to wire the CAN terminals.

Using display* parameters to set up the application (single DG without mains)

To set up the application for PMS lite, configure the following parameters:

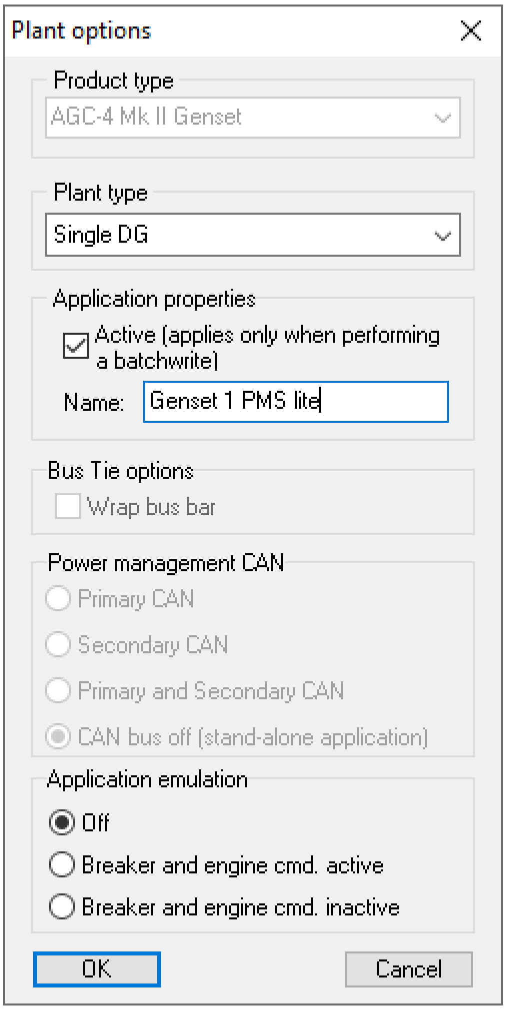
Parameter	Name	Range	Default	Details
9181	9180 Quick Setup	Off Setup stand alone	Off	Select **Setup stand alone**.

Parameter	Name	Range	Default	Details
		Setup plant		
9182	9180 Quick Setup	Off CAN PM Primary CAN PM Secondary CAN PM PRI + SEC	Off	Select **Off**.
9183	9180 Quick Setup	Pulse No MB Continuous Compact	No MB	Select **No MB**.
9184	9180 Quick Setup	Pulse Continuous Compact	Pulse	Select the generator breaker type.
9185	9180 Quick Setup	Mains present No mains present	No mains present	Select **No mains present**.
9186	9180 Quick Setup	SingleDG Standard	SingleDG	Select **SingleDG**.

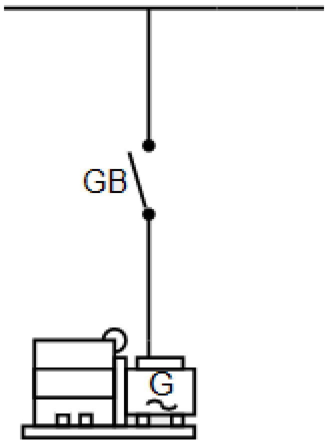
NOTE * For a DU-2, jump to menu 9180.

Using the utility software to set up the application (single DG without mains)

1. Create a new plant configuration. For *Plant type*, select *Single DG*:



2. When you select Single DG, the utility software shows an application drawing with a single generator*. You can select the generator breaker type here.



3. Write the application configuration to the controller:
   NOTE * For PMS lite, the source must only be a genset. Do not select mains as a source too.

How it works

When the controller connects to the CAN bus line, PMS lite automatically assigns the controller an ID.

4.4 Configuration

4.4.1 Load-dependent start and stop

Configure these parameters for PMS lite load-dependent start and stop.

Parameter	Name	Range	Default	Details
8501	PMS lite ld. start	1 to 100 % of nominal power 0 to 990 s	90 % 10 s	Send a request over PMS lite to start the next priority genset. The request is sent when the power of the controller's genset is more than the set point for the timer duration.
8503	PMS lite ld. stop	1 to 100 % 5 to 990 s	70 % 30 s	Send a request over PMS lite to stop the next priority genset. The request is sent when the power of the remaining genset(s) would be below the set point for the time duration. See the example below.

NOTE The load-dependent settings are not automatically shared between the PMS lite controllers. You can therefore use different load-dependent settings in each controller.

NOTE Do not use parameters 8001 to 8014, or 8301 to 8314. These parameters are for Option G5 Power management load-dependent start and stop.

Calculating load-dependent stop power

The plant consists of two gensets with 1500 kW nominal power each. The controllers have the default load-dependent stop settings.

When both gensets are running, the second genset can only stop if the load on the remaining genset would be below 70 %. That is, the second genset only stops if the load is below 1050 kW for 30 seconds.

4.4.2 Multi-start

The multi-start function is used when there is a black busbar and *Auto start/stop* is enabled.

The function has these three dimensions:

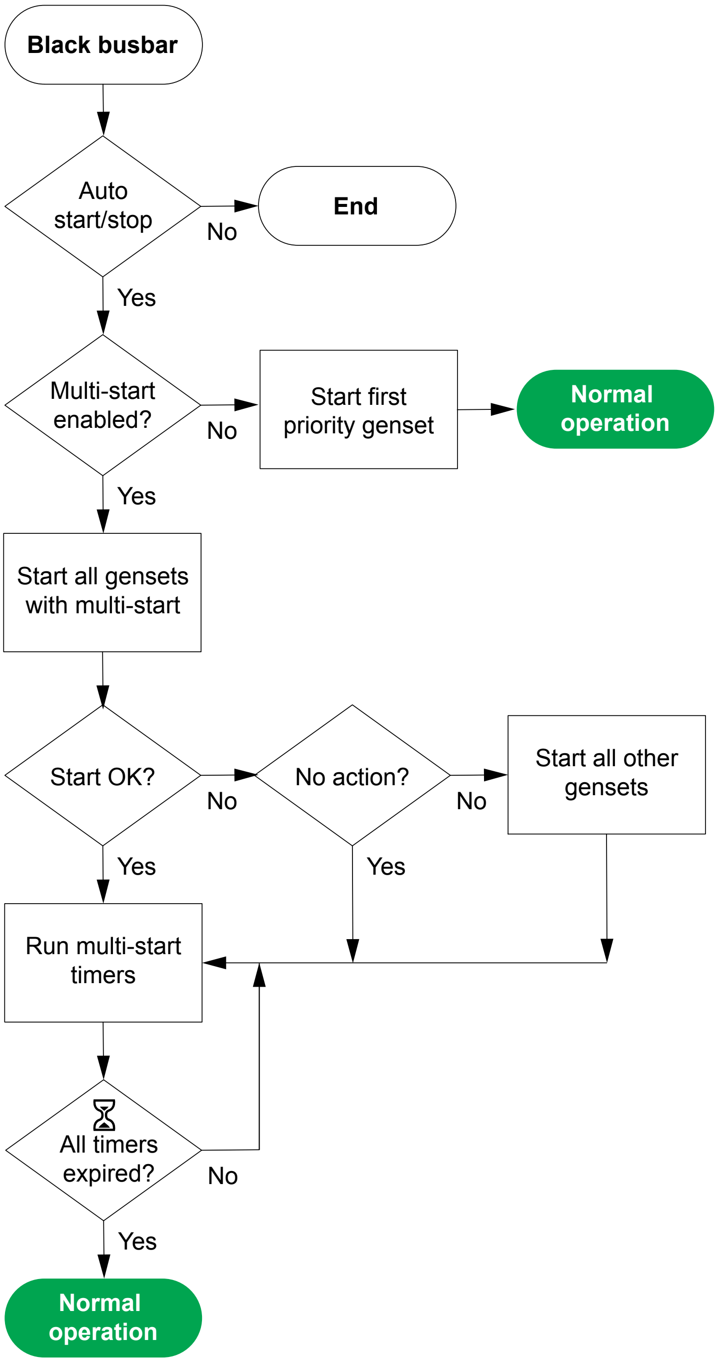
- For all the controllers where multi-start is enabled, the function makes sure that their gensets start. The gensets synchronise and connect to the busbar.

- If *Start all other DGs* is selected and a genset cannot start, the controller requests that all the other PMS lite controllers start their gensets.
- The timers delay the start of PMS lite load-dependent start and stop, until the last multi-start timer in the PMS lite application has run out.

The first priority genset connects to the busbar first. Once the first priority genset has connected to the busbar, the next priority genset connects to the busbar. If a genset fails to connect to the busbar, the next priority genset tries to connect to the busbar.

Parameter	Name	Range	Default	Details
8521	PMS lite multi start	No action on fail Start all other DGs 0 to 999.9 s Enabled, Not enabled	No action on fail, 60 s, Not enabled	See above.

Multi-start flowchart



4.4.3 Priority

You can configure a load-dependent start and stop priority for the controller. Multiple controllers can have the same priority. Controllers with the same priority are started and stopped at the same time. If multiple gensets have the same priority and multi-start is enabled, the genset with the lowest ID number connects to the busbar first.

The priority list starts with the configured priorities. Next, where there are no configured priorities, the controller IDs are used for the priority list.

Parameter	Name	Range	Default	Details
8512	PMS lite priority	0 to 127	0	**0**: The controller does not have a priority. **1 to 127**: Priority 1 starts first, and stops last.

NOTE Do not use parameters 8081 to 8106, or 8321 to 8343. These parameters are for Option G5 Power management priority.

4.4.4 Running hours

You can select how the running hours affect the genset priority. When the running hour conditions for a genset are met, PMS lite starts extra gensets until load-dependent stop can stop the genset.

Parameter	Name	Range	Default	Details
8531	Running hours	1 to 20000 h	2 h	Select the running hours for the priority change.
8533	Running hour type	Absolute Relative/trip Load profiled	Relative/trip	Select the running hours function. You must select the same running hour mode on all the controllers, otherwise, a *PMS lite Run hour type* alarm is activated. See below for more information.

Absolute

The running hours are based on the total genset running hours. You can see and adjust the total genset running hours in the *Counters* window in the utility software.

Relative/trip

The running hours are based on the time since the last reset. When the running hours conditions are met, the counter is reset.

Load profiled

The running hours are based on the time since the last reset, and weighted according to the genset load. For example, if the running hours set point is 100 hours, and the genset has been running at 50 % of nominal power, the genset will have to run for 200 hours before the running hours conditions are met.

4.4.5 Available power

The user can create an available power alarm. The user can use this alarm to activate M-Logic to respond to low available power.

Parameter	Name	Range	Default	Details
8540	PMS lite avail Power	10 to 30000 kW	1000 kW	If you select *Enable*, the alarm is activated if the required available power is not available.

NOTE This is not a function to control the available power. If you need to control the available power, you may need to use Option G5 Power management.

4.4.6 Minimum number to run

The user can create a minimum number of genset to run alarm. The user can use this alarm to activate M-Logic to respond if there are too few running gensets.

Parameter	Name	Range	Default	Details
8550	PMS lite min. run	1 to 128 0 to 360 s	1, 1 s	

NOTE This is not a function to control the number of running gensets. If you need to control the running gensets, you may need to use Option G5 Power management.

4.4.7 Baudrate

Parameter	Name	Range	Default	Details
8515	PMS lite baudrate	125kbps 250kbps	125kbps	For 50 or more PMS lite controllers, use 250kbps.

NOTE You must use the same baudrate in all of the PMS lite controllers.

4.4.8 Sharing parameters

You can use parameter 8514 to make the controller broadcast the PMS lite parameter settings to the other PMS lite controllers on the CAN line.

Parameters that are broadcast when using *Share parameters* (8514)

Parameter	Name
8501	PMS lite ld. start
8503	PMS lite ld. stop
8513	PMS lite fail mode
8531	PMS lite runn hours
8533	PMS lite RunHour Typ
8540	PMS lite avail Power
8550	PMS lite min. run
8560	PMS lite min. units
8570	PMS lite ID miss/add
8580	PMS lite ID not aval
8590	PMS lite duplicat ID

Parameter	Name	Range	Default	Details
8514	PMS lite share param	Off, On	Off	Select **On** to broadcast the parameters. All the parameters in the share parameters list are broadcast to other controllers over the PMS Lite CAN line. This takes about 10 seconds. After the parameters are shared, *PMS lite share param* is changed to **Off**.

4.5 PLC control

If required, a PLC can control the genset starts and stops. When a PMS lite controller is in PLC control:

- The controller ignores its own settings for load-dependent starts and stops.

- When it gets a PLC start signal, the controller starts its genset.
- When it gets a PLC stop signal, the controller stops its genset.

Activating PLC control

You can use parameter 8505 to activate PLC control. Alternatively, use the *PLC control start/stop* digital input or M-Logic to activate PLC control.

Parameter	Name	Range	Default	Details
8505	PMS lite start/stop	Load dependent start/stop PLC start/stop	Load dependent start/stop	Select **PLC start/stop** to activate PLC control.

NOTE If PLC control is not activated, the controller ignores PLC control start and stop signals.

PLC control start signals

You can use one of these to start the controller's genset:

- Digital input: *PLC control start*
- M-Logic: *Output > PMS lite commands > PLC control start*
- Modbus: Function code (01;05;15), Modbus address 14 or PLC address 15 (*Start+sync. (semi) / PLC control start+sync*)

PLC control stop signals

You can use one of these to stop the controller's genset:

- Digital input: *PLC control stop*
- M-Logic: *Output > PMS lite commands > PLC control stop*
- Modbus: Function code (01;05;15), Modbus address 15 or PLC address 16 (*Deload/stop (semi) / PLC control deload +stop*)

PLC control in operation

The PMS lite application can include both gensets that are under PLC control, and others that use load-dependent start and stop.

Be careful when doing a PLC control stop, because the PMS lite cannot make sure that there is enough available power after the genset stops.

Similarly, when you use a PLC control start, the load-dependent stop settings in the other controllers may respond by stopping a genset.

If you use PLC control when the controller is in AUTO mode, you must activate the auto start/stop input. If this is not activated, the controller ignores the PLC control start and stop signals.

4.6 PMS lite in operation

Controller IDs

When the controllers are connected to the CAN line, PMS lite IDs are automatically assigned to each controller (starting from ID 1).

You can manually assign an ID to a controller (parameter 8511). If you select an ID that has already been automatically assigned to another controller, the other controller automatically loses the ID (then reconnects to get a new automatic ID). If you select the same ID in two controllers, the *PMS lite duplicate ID* alarm is activated.

The user-defined priorities are the primary source of controller priority. The user-defined priorities determine the order of the first part of the priority list.

The controller IDs are the secondary source of controller priority. Controllers that do not have user-defined priorities make up the second part of the priority list. For these controllers, the priority order is determined by their controller IDs.

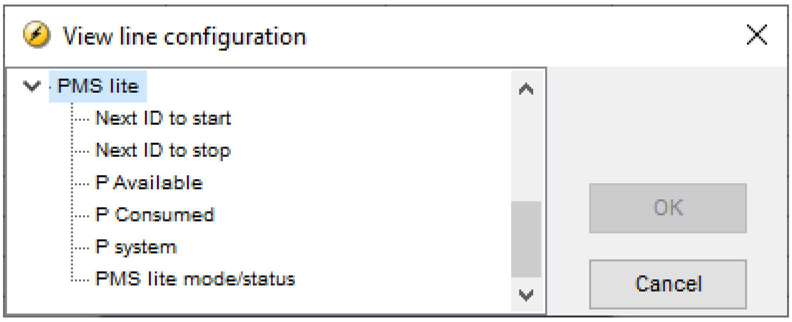
NOTE To avoid disrupting the plant, do not change the IDs while the plant is running.

Parameter	Name	Range	Default	Details
8511	PMS lite ID	0 to 127	0	**0**: The PMS lite ID is automatically assigned.
8590	PMS lite duplicate ID	Fail classes	Warning	

More information
See **PMS lite not available** in **Communication failures** for what to do when the *PMS lite ID not available* alarm is shown.

PMS lite information in the display

In the utility software, select *Configuration of the user views*. In the *Device display* box, select a view line to configure. In the *View line configuration* box, select the information to display. Remember to write the selection to the controller.



More information
See **PMS lite in operation** in the **AGC 150 PMS lite Designer's handbook** to see the operation overview that the AGC 150 PMS lite can show.

4.7 Communication failures

Minimum number of PMS lite controllers

An alarm can be activated if the required number of PMS lite controllers is not detected on the CAN line.

Parameter	Name	Range	Default	Details
8560	PMS lite min. units	1 to 128 0 to 360 s	1, 0 s	Select the minimum number of PMS lite controllers.

PMS lite ID missing or added

This alarm can only be activated if the plant has been stable (no controllers added or removed) for at least 30 seconds. The number of controllers and 30 second timer resets after the alarm is acknowledged.

Parameter	Name	Range	Default	Details
8570	PMS lite miss/add	0 to 10 s	0 s	The alarm is activated when PMS lite controller(s) are missing or added for the timer duration.

PMS lite ID not available

The alarm is activated if the PMS lite ID cannot be manually assigned:

- For the controller where the user is trying to manually assign the ID, the genset is running*.
- The ID is already manually assigned to another controller.
- Another controller has the ID (automatically or manually assigned), and its genset is running*.

NOTE The controller ID cannot be changed if its genset is running.

Parameter	Name	Range	Default	Details
8580	PMS lite ID not aval	You can select the alarm action.	Warning	The alarm is always enabled.

Duplicate controller IDs

An alarm is activated if two or more controllers have the same ID. This can happen during plant initialisation or when two PMS lite plants are connected.

Parameter	Name	Range	Default	Details
8590	PMS lite duplicat ID	You can select the alarm action.	Warning	The alarm is always enabled.

4.8 M-Logic commands and events

`Output > PMS lite commands`

Description	Notes
PLC control start	If PLC control is active, start the genset.
PLC control stop	If PLC control is active, stop the genset.
Enable multi start	Change *Multi start config* (parameter 8521) to *Enabled*.
Disable multi start	Change *Multi start config* (parameter 8521) to *Not enabled*.
Share PMS lite set points	Share the PMS lite parameters. This corresponds to selecting *On* in *Share parameters* (parameter 8514).
Set LDSS control	Use the controller's PMS lite load-dependent start and stop settings, and ignore the start and stop commands from a PLC. This corresponds to selecting *Load dependent start/stop* in *PMS lite start/stop* (parameter 8505).
Set PLC control	Use start and stop commands from a PLC, and ignore the PMS lite load-dependent start and stop settings. This corresponds to selecting *PLC start/stop* in *PMS lite start/stop* (parameter 8505).
Set to first priority	Make this controller first priority for PMS lite. This corresponds to parameter 8512.
Set multi start failure mode to no action	Change *Multi start config* (parameter 8521) to *No action on fail*.
Set multi start failure mode to start all DGs	Change *Multi start config* (parameter 8521) to *Start all other DGs*.

`Events > PMS lite event`

Description	Notes
Min number to run alarm	The *Minimum number to run* alarm is activated in the controller.
Min number of units alarm	The *Minimum number of units* alarm is activated in the controller.
Available power alarm	The *Available power* alarm is activated in the controller.
Next to start	The controller is the next to start its genset if this is required by PMS lite.
Next to stop	The controller is the next to stop its genset if this is required by PMS lite.
Multi start enabled	*Multi start config* (parameter 8521) is *Enabled*.
LDSS control active	PLC control is not active for the controller.
PLC control active	PLC control is active for the controller.
First priority	The controller has first priority.

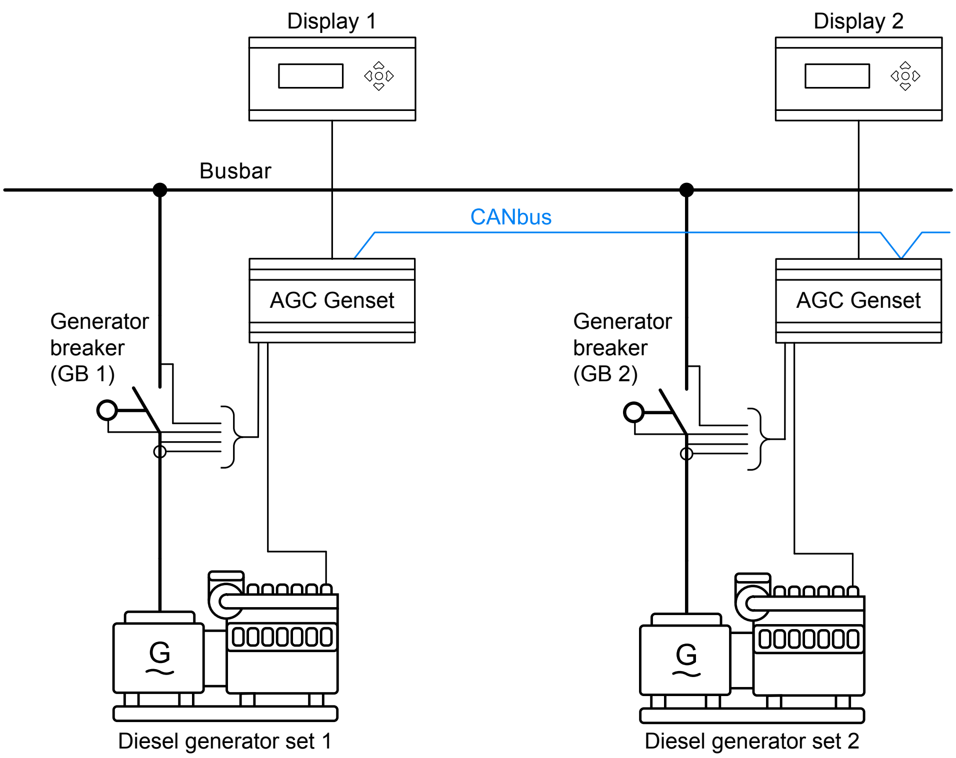
5. Applications with power management

5.1 Single-line diagrams

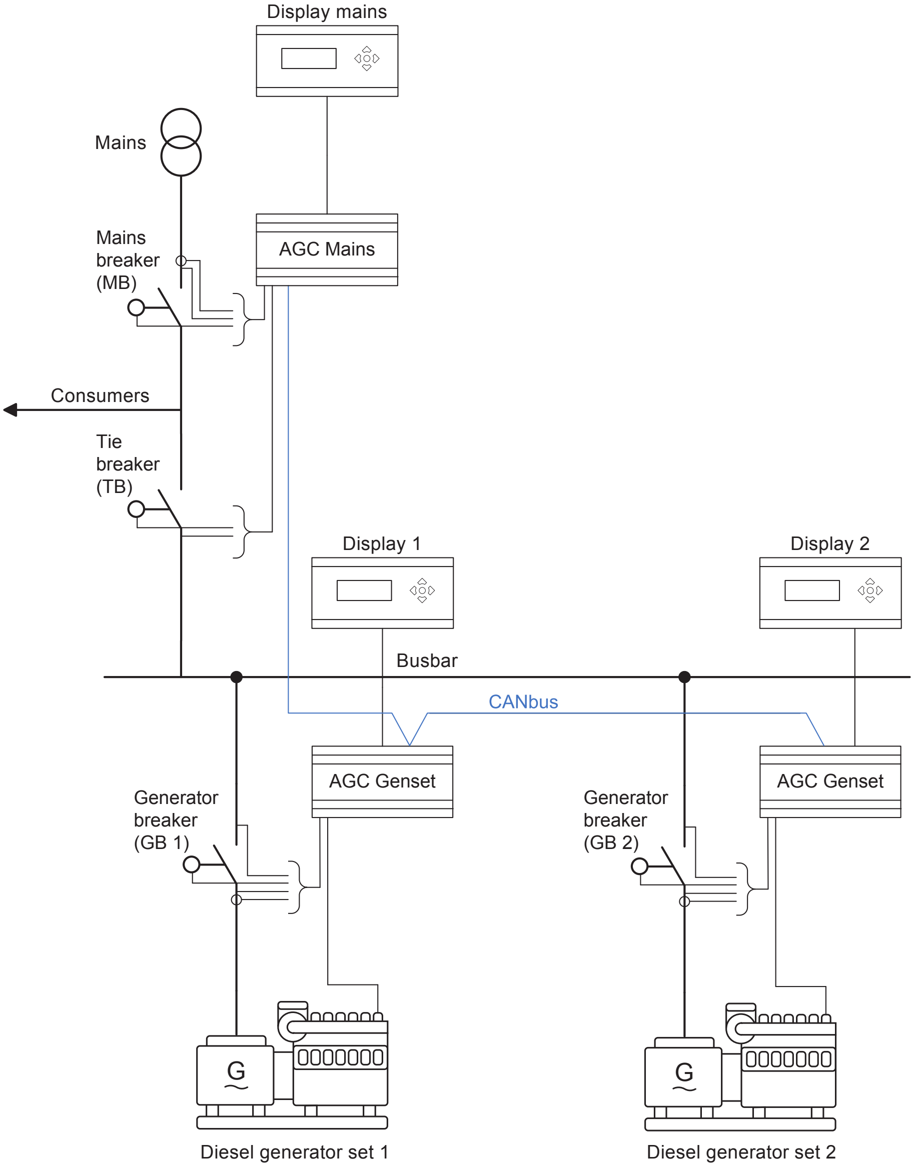
The following single-line diagrams show a variety of AGC applications that use power management (option G5).

More information
See **Option G7 Extended power management** for information about using group and plant controllers.

5.1.1 Island operation

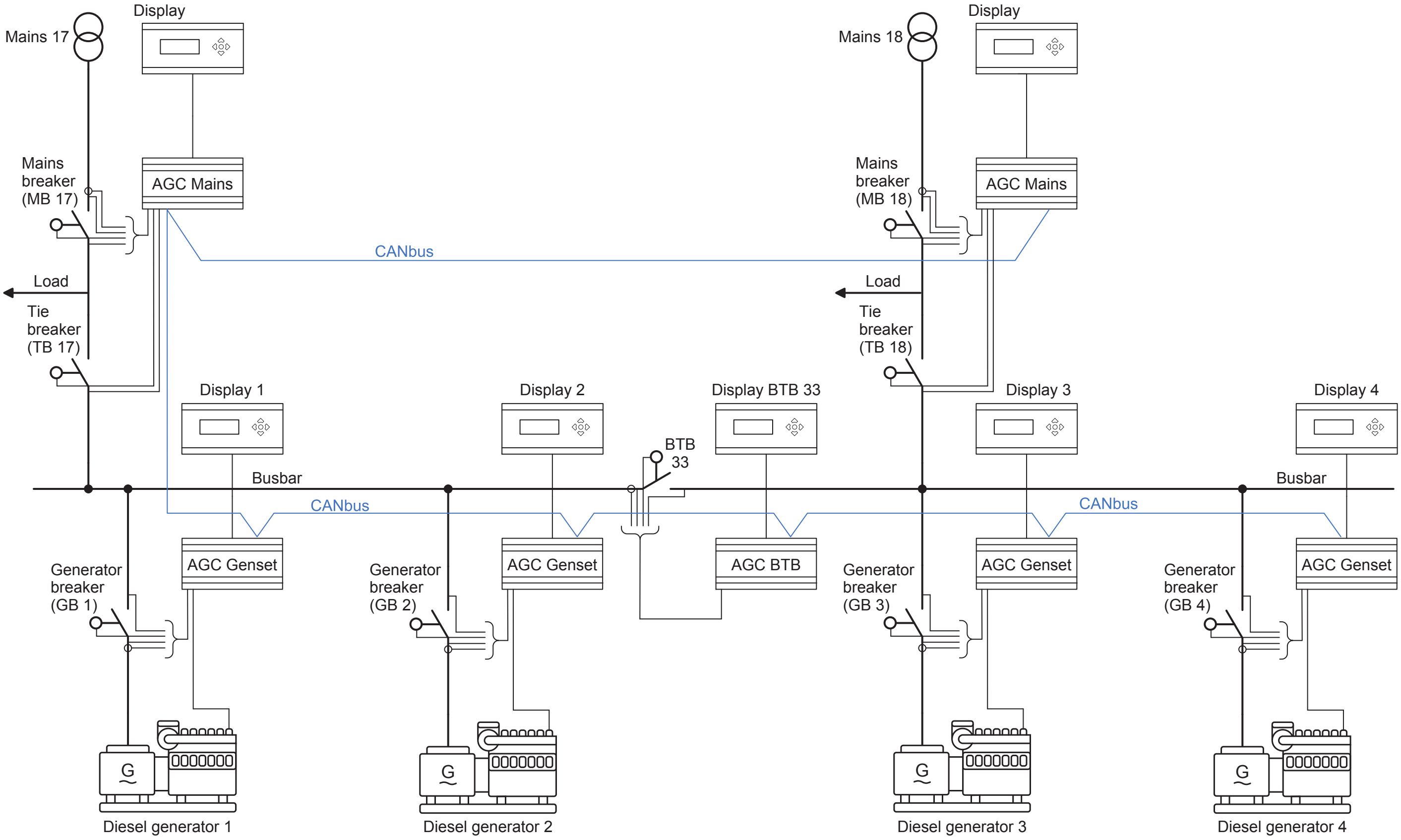


5.1.2 Parallel to mains



5.1.3 Multiple mains

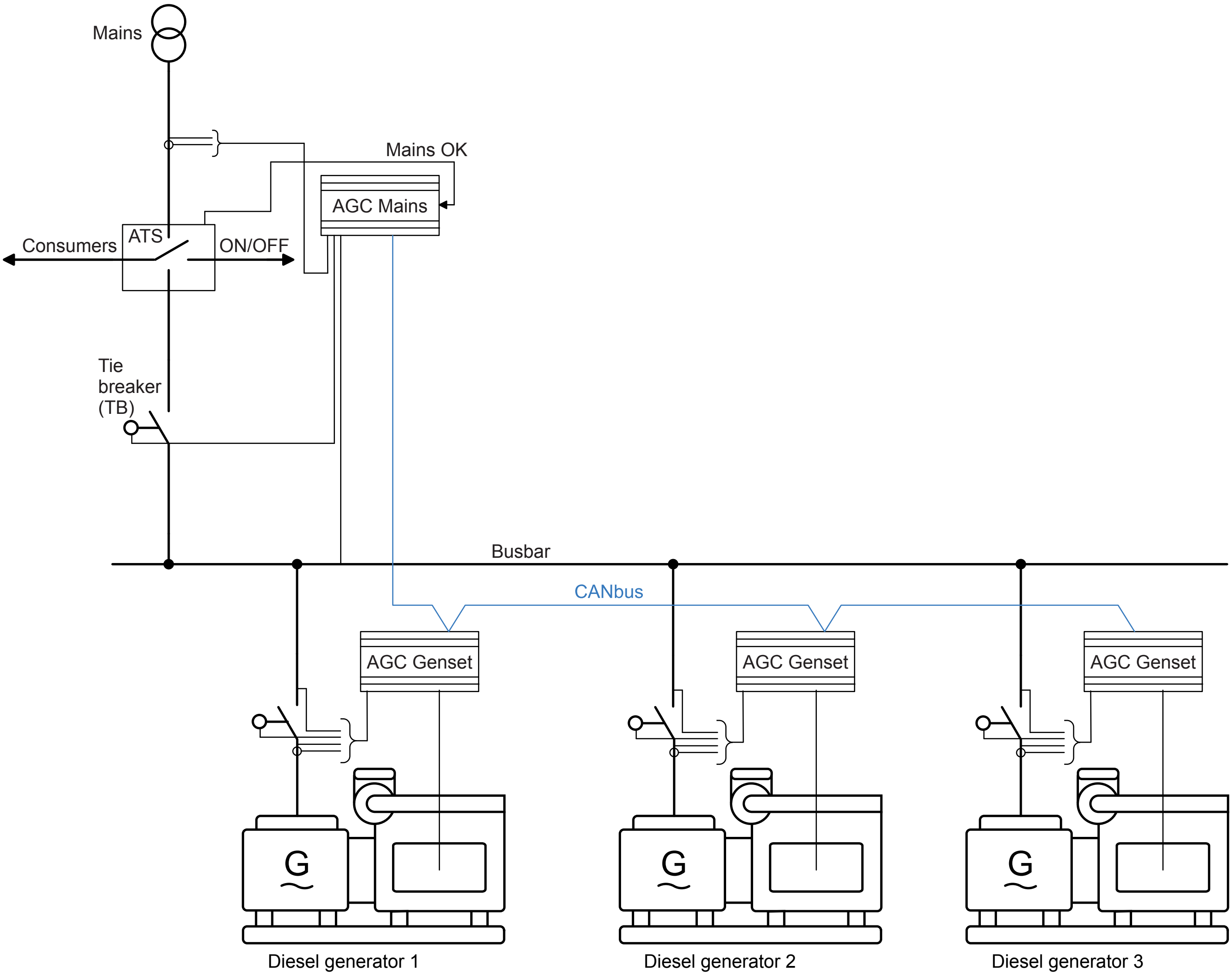
Multiple mains with two mains, two tie breakers, one bus tie breaker and four gensets



NOTE The diagram shows four generators, but the system supports up to 32 generators. For more information, see **Option G5**.

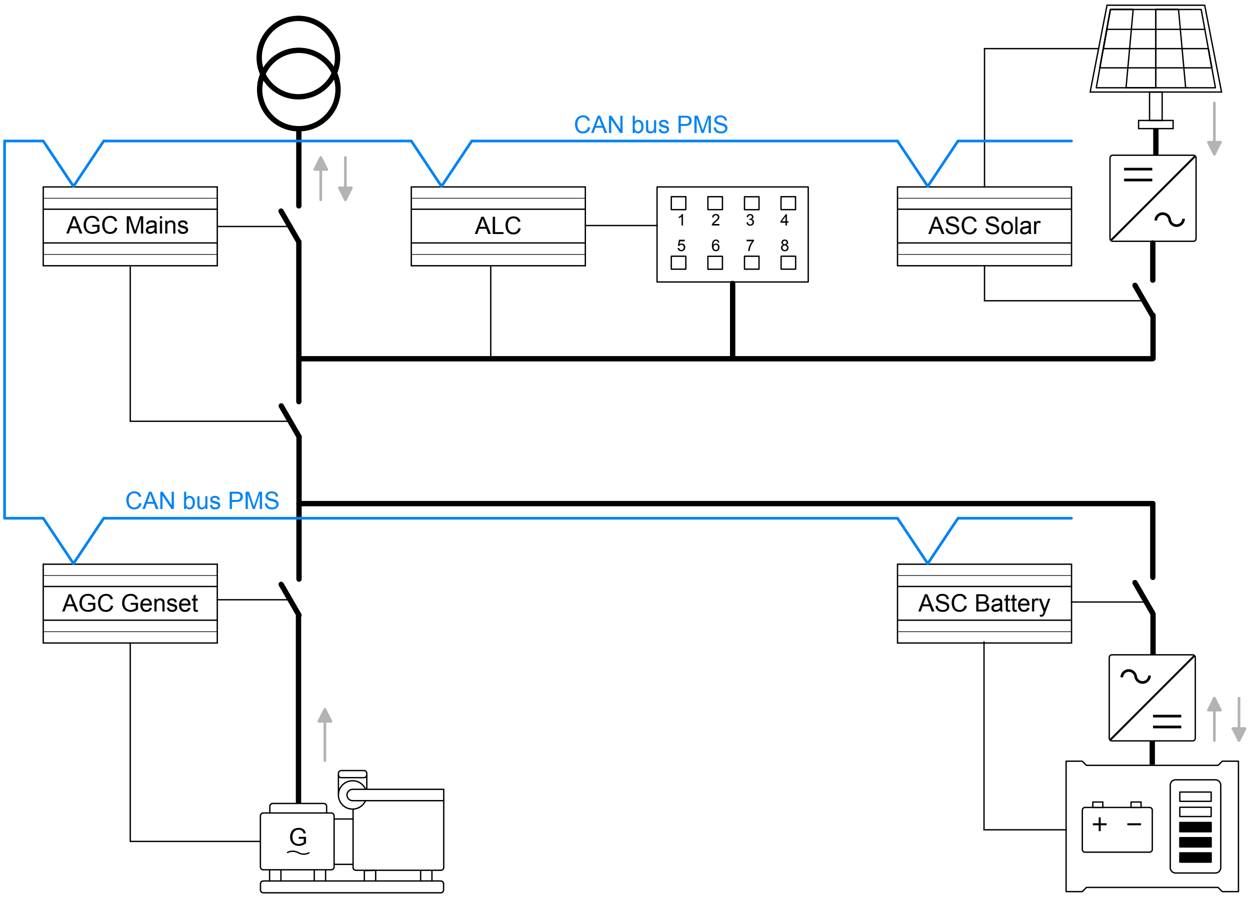
5.1.4 Automatic transfer switch

ATS plant, Mains controller

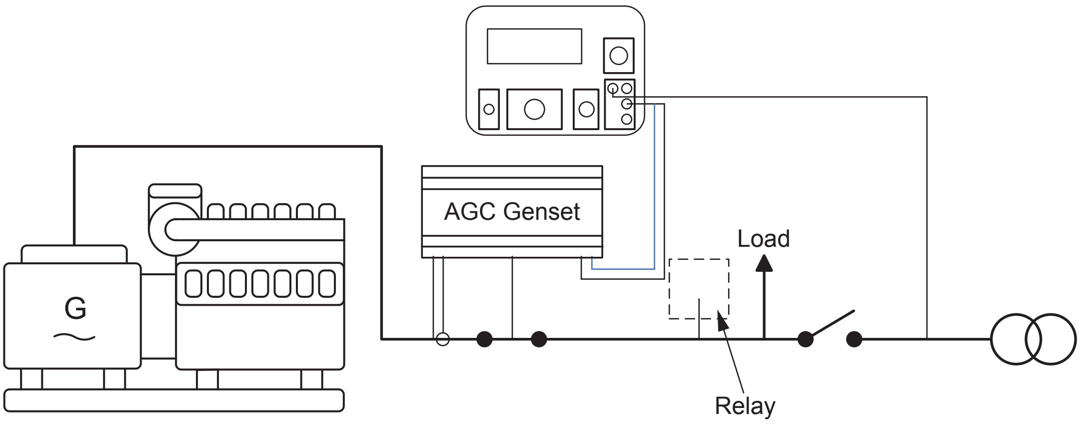


NOTE The simple ATS function (a *Mains OK* signal is sent to an AGC digital input) is shown here. See **Option G5 Power management** for a description of the more advanced ATS function.

5.1.5 Energy management system



5.1.6 Remote maintenance



More information
See the **Operator's manual** of the remote maintenance box for more information.

5.2 Power management documentation

More information
See **Option G5, Power management, Genset, Mains and BTB controllers** for how to set up a power management system, parameters and functions.

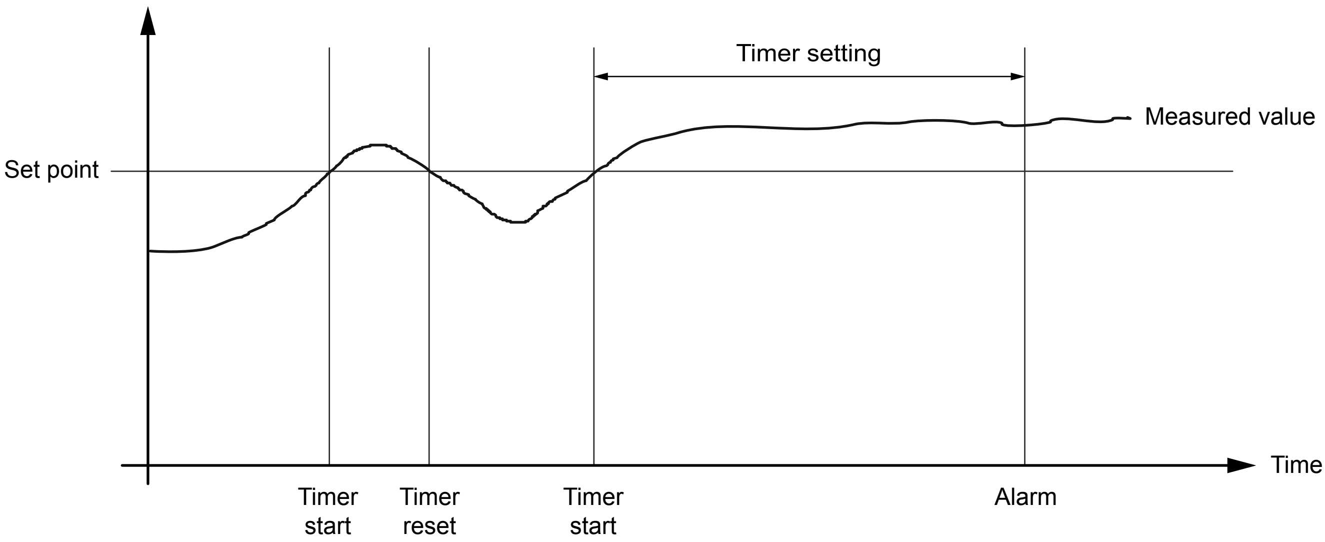
More information
See **Option G7, Extended power management (>32 gensets)** for how to set up an extended power management system, parameters and functions.

6. Standard protections

6.1 General

The protections are all of the definite time type, that is, a set point and time is selected.

If, for example, the function is over-voltage, the timer is activated if the set point is exceeded. If the voltage value falls below the set point value before the timer runs out, the timer is stopped and reset.



When the timer runs out, the output is activated. The total delay will be the delay setting + the reaction time.

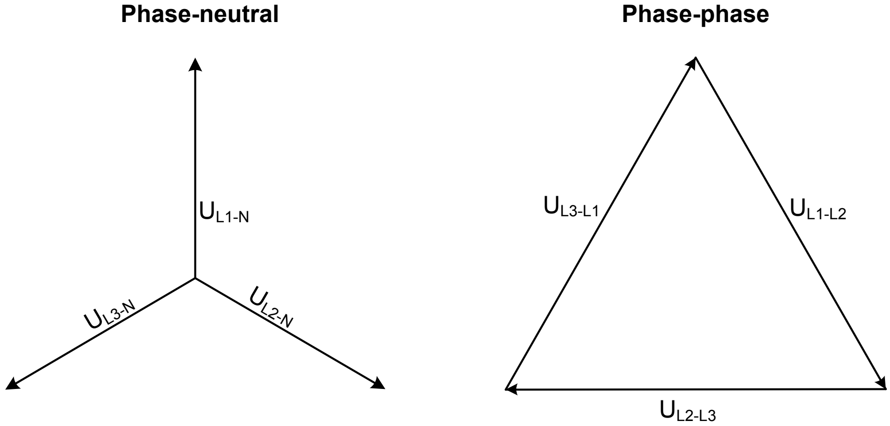
When configuring the parameters in the DEIF controller, the measuring class of the controller and an adequate "safety" margin must be considered.

Example

A power generation system must not reconnect to a network when the voltage is 85 % of Un +/-0 % $\leq$ U $\leq$ 110 % +/-0 %. In order to ensure reconnection within this interval, the controller's tolerance/accuracy (Class 1 of the measuring range) has to be taken into consideration. It is recommended to set the range 1 to 2 % higher/lower than the actual set point, if the tolerance of the interval is +/-0 %, to ensure that the power system does not reconnect outside the interval.

Phase-neutral voltage trip

If the voltage alarms must work based on phase-neutral measurements, adjust parameters 1201 (genset/mains/busbar A) and 1202 (busbar) accordingly. You can select whether phase-phase voltages, phase-neutral voltages, or phase-phase or phase-neutral voltages are used.



As indicated in the vector diagram, there is a difference in voltage values at an error situation for the phase-neutral voltage and the phase-phase voltage.

The table shows the actual measurements at a 10 % under-voltage situation in a 400/230 volt system.

	Phase-neutral	Phase-phase
Nominal voltage	**400/230**	**400/230**
Voltage, 10 % error	380/**207**	**360**/185

The alarm will occur at two different voltage levels, even though the alarm set point is 10 % in both cases.

Example

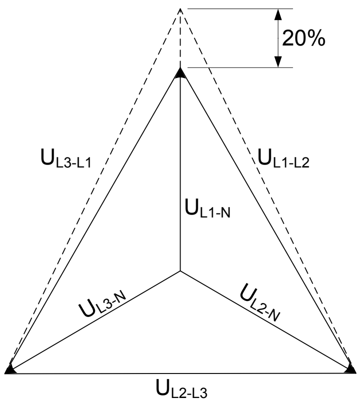
The following 400 V AC system shows that the phase-neutral voltage must change 20 %, when the phase-phase voltage changes 40 volts (10 %).

Example:
U_{NOM} = 400/230 V AC

Error situation:
U_{L1L2} = 360 V AC
U_{L3L1} = 360 V AC

U_{L1-N} = 185 V AC

ΔU_{PH-N} = 20 %

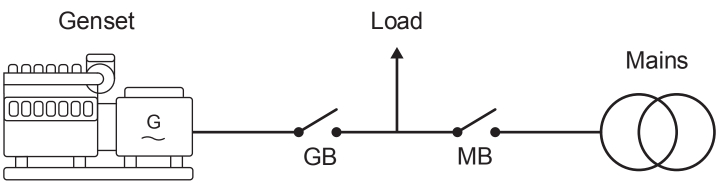


6.2 Phase sequence error and phase rotation

The AGCs is able to monitor the rotation of the voltage, and to give an alarm if the voltage is rotating in the wrong direction. The AGC can monitor the rotation in both direction. From the alarm it is possible to set different failclasses, which give different possibilities. The documentation about phase sequence error can divided into two sections, where the first chapter will be about Single DG applications, and the other chapter will be about standard/multiple controller applications.

6.2.1 Single DG applications

A single DG application is able to handle up to one genset, one generator breaker and one mains breaker. An application like this is shown below:



When the AGC is mounted correctly, the gensets voltage measurements are mounted between the Generator Breaker (GB) and the genset. The other voltage measurements are mounted between the Mains Breaker (MB) and the incoming grid connection. On the different controllers the voltage terminals is shown below:

Genset voltage terminals	Mains voltage terminals
79-84	85-89

NOTE The table above is only for Single DG application!

In the AGC there are two different alarms concerning the phase sequence error, and hereby two different fail classes. The alarm for phase sequence error and phase rotation is set in parameter 2150. The parameters are described in the table below:

Parameter	Menu text	Description
2151	Output A	Relay output if the AGC detects a phase sequence error on the genset voltage terminals.
2152	Output B	Relay output if the AGC detects a phase sequence error on the genset voltage terminals.
2153	fail class	Determines how the AGC reacts if the AGC sees a phase sequence error on the genset voltage terminals.
2154	Rotation	Determines the rotation of the voltages the AGC is measuring on. This is both for the genset voltages and mains voltages.
2155	Output A	Relay output if the AGC detects a phase sequence error on the mains voltage terminals. Since there is no output B on this alarm, it has been configured that output B is the same as output A.
2156	fail class	Determines how the AGC reacts if the AGC sees a phase sequence error on the mains voltage terminals.

Example

In a Single DG application with GB and MB (like the application shown previously), the parameters are set like in the table below:

Parameter	Menu text	Description
2151	Output A	Not used
2152	Output B	Not used
2153	fail class	Trip+Stop
2154	Rotation	L1L2L3
2155	Output A	Not used
2156	fail class	Trip MB

NOTE An alarm is activated if no relay output A/B is selected. Do not chose *Limits* if you want that an alarm is activated together with a relay output A/B.

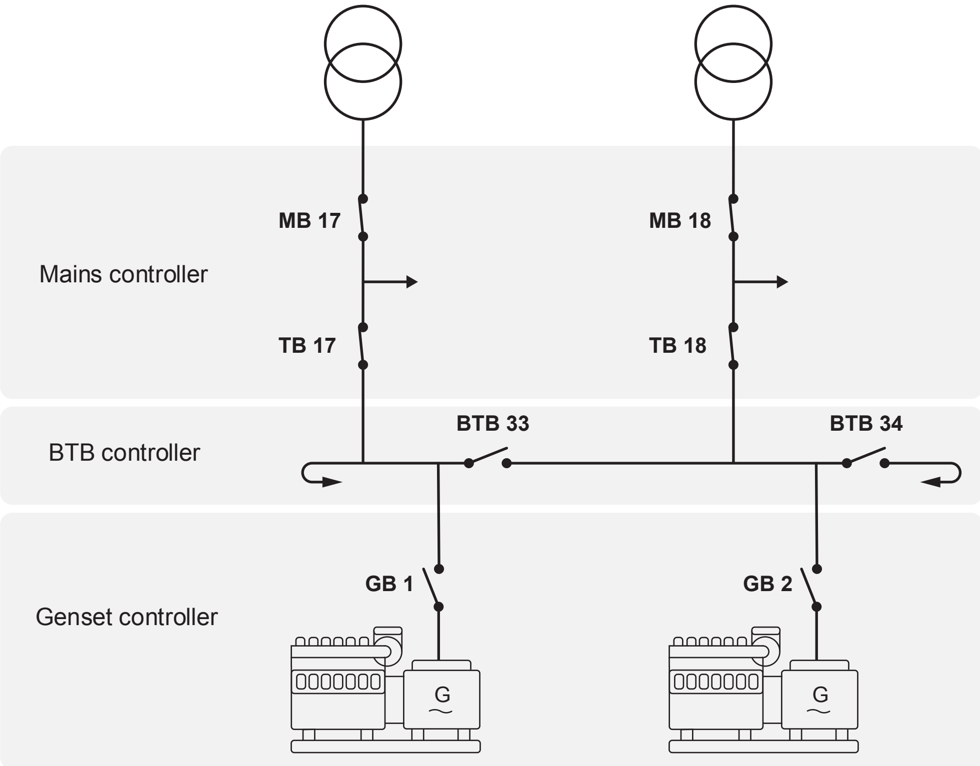
If the controller is set to Load Take Over (LTO) and the start signal is given the genset will start up. If there have been performed a service of the alternator, and two of the phases have been switched when the alternator has been assembled again, the AGC will now discover a phase sequence fail. Since this is on the genset voltage terminals, the fail class set in parameter 2153 will be used. The fail class is set to Trip+Stop, which will trip the breaker (If the breaker is not closed, the controller will not send a trip signal), and then afterwards go into the stop sequence. If the alarm is acknowledged, the genset will start up again, if the start signal is still present.

In this plant there could be a situation where there is some changing in the grid. If the grid company is coupling in the grid, and the phase sequence in changed on the grid connection, and the Mains fail timers does not react on the small blackout, the fail class in parameter 2156 will be used. At the moment there is a phase sequence error on the mains voltage terminals, and the fail class is Trip MB. When the MB is tripped, the genset is started, since there is a trip alarm MB, and load does not have any power at the moment. In the same plant it can be possible to that a service of the transformer is going to happen. To test the Automatic Mains Failure (AMF) sequence, the technician removes the fuses, and the AGC will then discover the voltage is not present and afterwards start up the genset and take the load. When the technician is assembling the transformer again he accidentally switches two phases. When the fuses is set into place again, the AGC will discover a phase sequence error on the mains voltages, and by this it will still keep running, until the phase sequence has been fixed.

6.2.2 Standard/multiple controller applications

In these applications there are different types of controllers. The three different types are: Genset, Bus Tie Breaker (BTB) and Mains. The phase sequence alarms are located at parameter 2150. From here it is possible to configure both the alarms for phase sequence errors and also the phase rotation.

The alarms refer to different voltage terminals. The different types and models of controllers have different terminals. To know which voltage terminals the different alarms refers to, the drawing and tables below can be helpful.



For mains controllers the table below is applicable:

Mains voltage terminals	Busbar voltage terminals
79-84	85-89

NOTE The table above is only for Mains controllers in standard plants!

For BTB controllers the table below is applicable:

Bus A voltage terminals	Bus B voltage terminals
79-84	85-89

NOTE The table above is only for BTB controllers in standard plants!

For Genset controllers in a single DG application, the table below is applicable:

Genset voltage terminals	Mains voltage terminals
79-84	85-89

For Genset controllers in a power management application, the table below is applicable:

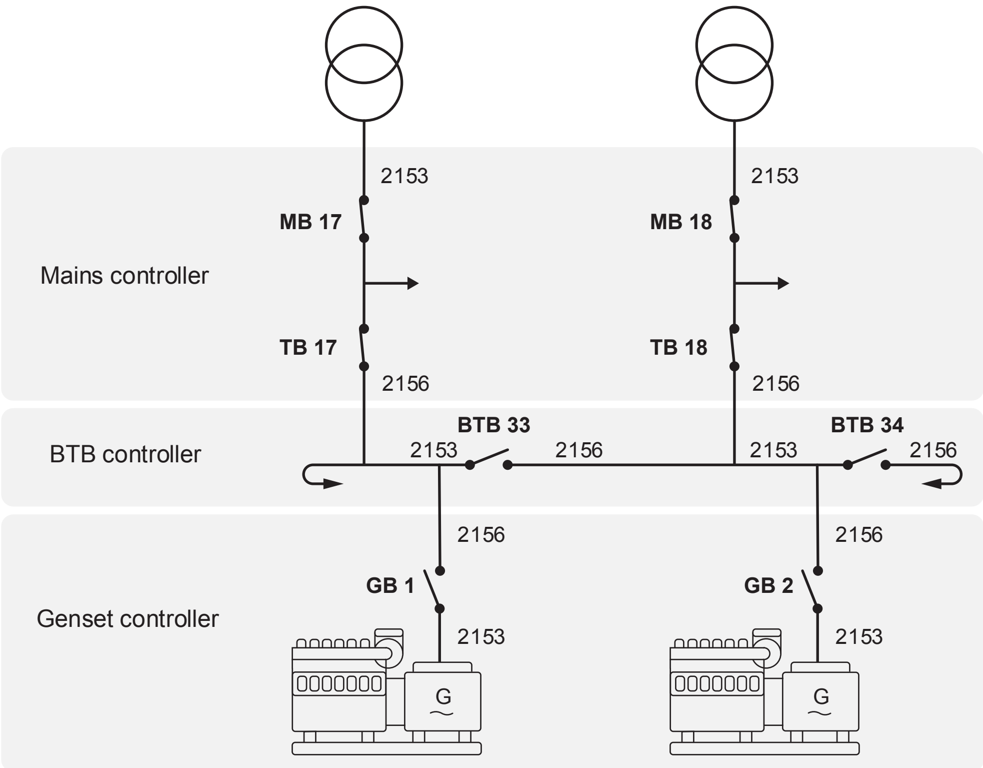
Genset voltage terminals	Busbar voltage terminals
79-84	85-89

Parameter 2150 is consisting of two alarms, and the phase rotation direction setting. The phase rotation setting is the same for the both terminal sets. The two alarms refer to the voltage terminals. To know which alarm refers to voltage measurement, the table below has been made to make an overview:

Menu/Parameter no.	Mains controller	BTB controller	Genset controller
2153	Mains voltage	Bus A voltage	Genset voltage
2156	Busbar voltage	Bus B voltage	Busbar voltage

The diagram made earlier, can be helpful in locating where the different location of each voltage measurement is made.

The table above shows on which terminal set the phase sequence error occurs to activate the fail class set in the parameter 2153 and 2156. This can also be shown in a diagram like this:



When setting up the phase sequence alarms, it can be helpful to activate MB fail start (8181) in some of the mains controllers. This gives the possibility if e.g. the phase sequence error for mains voltage (2153) appears, and the fail class is Trip MB, then the gensets will start. If then autoswitch is enabled also (8184) the other grid connection can supply as backup load, before the gensets will start. If the other mains do not have a phase sequence error, the other mains will keep on supplying the load, and the gensets will not start.

Example

On genset 1, parameter 2153 is set to trip+stop. Genset 1 has recently been out for service, and two phases has accidentally been switched. A mains fail now occurs on mains 17, and genset 1 will start up. The controller for genset 1 sees a phase sequence error here, and activates its fail class. GB1 will never be closed. BTB33 will now close, and genset 2 will start up and supply the load. If there also is a phase sequence error on the B side of BTB33, and 2156 in BTB 33 is set to trip BTB, the system will close BTB34 instead, since this is a system with wrapped busbar.

6.3 Loss of excitation

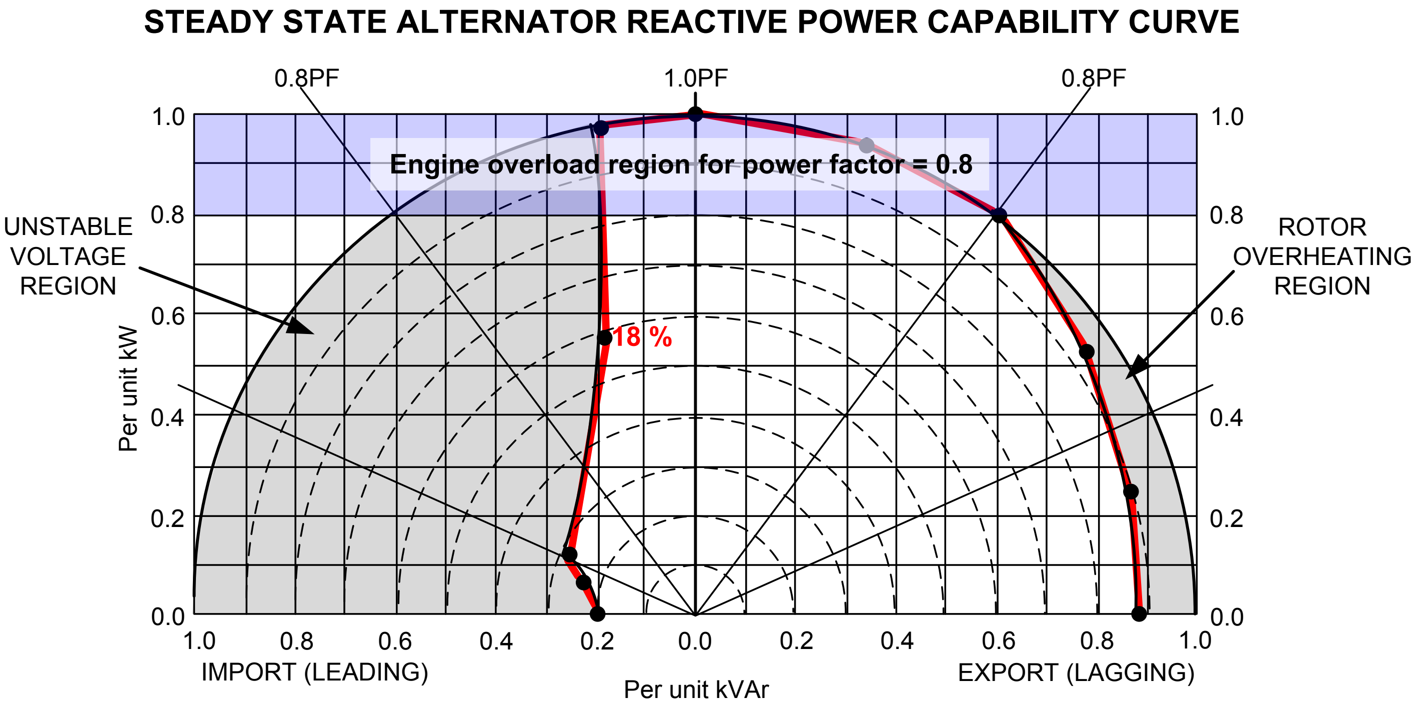
To prevent damage to the generator because of a pole slip, the AGC can trip a breaker if loss of excitation occurs. The protection is configured in menu 1520.

The percentage in parameter 1521 is the maximum percentage of imported kvar compared to the nominal kW of the genset.

Genset example

The genset has a nominal of 1000 kW. Parameter 1521 is 15 %. This means that if the genset is 150 kvar capacitive or more, the timer in parameter 1522 starts. When the timer expires, an action occurs. This action/fail class is configured in parameter 1526.

To configure the percentage correctly, a calculation must be made. The operating chart for the generator is needed. An example of an operating chart for a generator is shown below. The blue block shows the engine overload at a power factor of 0.8.



The alternator 100 % load is the outer circle, and the engine 100 % load is the bottom of the blue block. With the operating chart it is possible to see where the alternator-safe line is closest to the 1.0 PF line. In this operating chart each vertical line represents 10 %, and so the point closest to 1.0 PF is 18 %. Use the nominal alternator values and the nominal engine values to do the calculations.

Calculating parameter 1521

The reading of 18 % is used. The alternator has a nominal power of 2500 kVA, and the engine has a nominal power of 2000 kW. The distance between the reading and the 1.0 PF line represents a power: 2500 kVA * 18 % = 450 kvar

The setting of parameter 1521 can now be calculated: 450 kvar / 2000 kW = 22.5 %

NOTE This protection does not prevent engine overload. To protect against engine overload, configure the generator overload protections in menus 1450 to 1490.

6.4 Voltage-dependent over-current

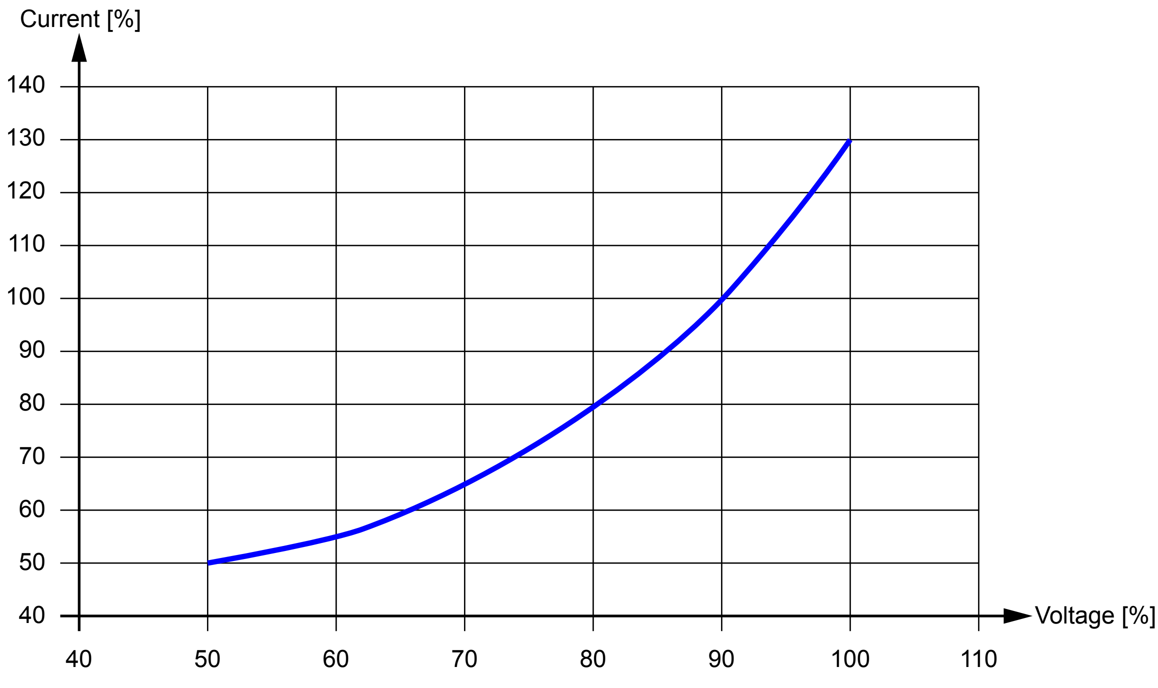
The voltage-dependent over-current is a protection for generators without permanent magnets. This protection occurs when a short circuit is present and the voltage drops. When a short circuit occurs, the voltage will make a drop and the current will rise for a very short period and then drop to a lower level afterwards. The short circuit current level can drop below the rated current of the generator, and thus the short circuit will not be tripped, which may result in personal injury or damaged equipment. When the short circuit is present, the voltage will be low. This can be used for tripping at a lower current, when the voltage is low.

The parameters for this are 1101 to 1115. The set points for the different levels are set in parameters 1101 to 1106. The set point refers to six different current levels and voltage levels. All values are in percentage to the rated values that are set in parameters 6000 to 6030. The six voltage levels are already determined, so only the current levels must be set. The six set points will create a curve, which will be explained by an example:

The six different set points have been set to the values shown in the table below.

Parameter	1101	1102	1103	1104	1105	1106
Voltage level (Fixed/not adjustable)	50	60	70	80	90	100
Current level (Set point/adjustable)	50	55	65	80	100	130

The six values can then be transferred to a curve, which is more readable:



When the actual values represent a point above the curve, the breaker should be tripped. The curve shows that the generator breaker will trip when two requirements are met: The generator voltage is below 50 % of rated, and the current is above 50 % of rated.

Timer, outputs, enable and fail class are set in parameters 1111 to 1115. The timer in 1111 decides how long the fault will exceed the limits, before an action will take place. The action/fail class is decided in parameter 1115 and can be set from a warning to a shutdown. As a default, this will be set to trip the generator breaker. The outputs can be used to activate a relay. This will make it possible to send a signal to external equipment regarding this specific alarm. It is possible to configure two relay outputs for the alarm. The protection function is activated as a default, but can be disabled in parameter 1114.

6.5 Unbalanced current

The generator can be in a situation where it is not delivering its rated load, but the current is very high in one of the phases. This can be caused by an unbalanced load. When a generator load is unbalanced, the stress on the generator will be higher than normal. The heat in one of the windings can also be very high. Unbalanced load can also develop if a cable has been damaged or dropped off, or if a fuse to a single phase has blown. To protect the generator from unnecessary stress, the protection against unbalanced load can be used. It is located in parameters 1501 to 1506. Parameter 1203 is also related to these parameters. Parameter 1203 defines how the calculations should be done, and it can be set to nominal or average.

If parameter 1203 is set to nominal, the AGC uses the maximum and the minimum current and subtracts the values. Then it will compare this to the nominal current typed in parameter 6003, 6013, 6023 or 6033, depending on which of the nominal settings is activated. The comparison to the nominal current will give a percentage that is related to parameter 1501.

Example: A genset is rated at 400 A and is supplying a load. The currents of the three phases are: 115 A, 110 A and 100 A. The AGC will use the maximum and the minimum current, in this case 115 A and 100 A. The calculation will now be: ((115 - 100)*100)/400 = 3.75 %. If parameter 1501 is set to 4 %, the genset will keep running. If parameter 1501 is set to 4 %, and the genset's rated current is 400 A, it can be calculated how unbalanced the genset is allowed to be: (4*400)/100 = 16 A. When the phases are loaded more than 16 A, the generator breaker will be tripped. This is independent of the size of the load.

Parameter 1203 can also be set to average. The AGC will then calculate an average of the phases and compare how unbalanced the load is between them.

Example: An genset is rated at 400 A and is supplying a load. The currents of the three phases are: 115 A, 110 A and 100 A. The AGC will now calculate an average of these currents, take the one that differs most from the average and calculate a percentage of deviation: (115 + 110 + 100)/3 = 108.3 A. Then the AGC will analyse which of the currents that differs most. In this example, it will be the 100 A. The maximum difference will be compared to the average current: ((108.3 - 100)*100)/108.3 = 7.7 %. If the load had been bigger, this calculated percentage would have been smaller. If the phase currents were 315 A, 310 A and 300 A, the average would be: (315 + 310 + 300)/3 = 308.3 A. This would give a deviation of:

((308.3 - 300)*100)/308.3 = 2.7 %.

6.6 Unbalanced voltage

As well as having an unbalanced current protection, the AGC also has an unbalanced voltage protection. The AGC will measure on each of the phase voltages and compare them to each other. If the genset is mounted in an application with capacitors to compensate and a failure occurs in one of the capacitors, a difference in voltage may appear. The windings for this phase will be overheated and thus exposed to heavy stress. To prevent this, the unbalanced voltage protection can be set.

The percentage set in parameter 1511 is a percentage of deviation compared to the average voltage in the three phases. The average comparison is described with an example below.

Example: Phase L1 to L2 is 431 V, phase L2 to L3 is 400 V and phase L3 to L1 is 410 V. The three voltages must be added up to find an average voltage: (431 + 400 + 410)/3 = 414 V. Now the voltage with the biggest voltage difference must be subtracted, in this case L1 to L2: 431 - 414 = 17 V. Now the biggest voltage deviation in percent can be calculated: (17/414)*100 = 4.1 %.

This means that if parameter 1511 is set to 4.1 %, it is allowed to have a voltage difference of 31 V in this application, before the unbalanced voltage protection can be activated.

In the example, phase-phase measurements have been used. Phase-phase is selected as default, but it can also be phase-neutral measurements, and this can be changed in parameter 1201. (Parameter 1201 will be described later).

NOTE Be aware that when parameter 1201 is changed, it will influence other protections.

In parameter 1512 the timer can be set, and in parameter 1515 this protection is enabled. In parameter 1516 the fail class is decided. It is also possible to enable two relay outputs when the alarm occurs. The two relay outputs can be set in parameters 1513 and 1514.

6.7 Over-excitation

When heavy inductive loads are connected, over-excitation of the generator can occur. Alternatively, over-excitation can occur if the load of a generator quickly changes from inductive to capacitive. Over-excitation can also occur in an application with more than one generator if one of the generators' exciter fails. Over-excitation can overheat windings in the generator and create a failure over time.

Example: Setting over-excitation

The engine is 2000 kW, and the alternator is 2500 kVA.

Calculate how many kvar the genset can export:

$Q = \sqrt{S^2 - P^2} = \sqrt{2500^2 - 2000^2} = 1500\ kvar$

Use the kvar to calculate the percentage for parameter 1531: kvar/kW = 1500/2000 = 75 %.

When parameter 1531 is 75 %, the genset can export up to 1500 kvar. The alarm is activated when the load has crossed the set point for the time in parameter 1532.

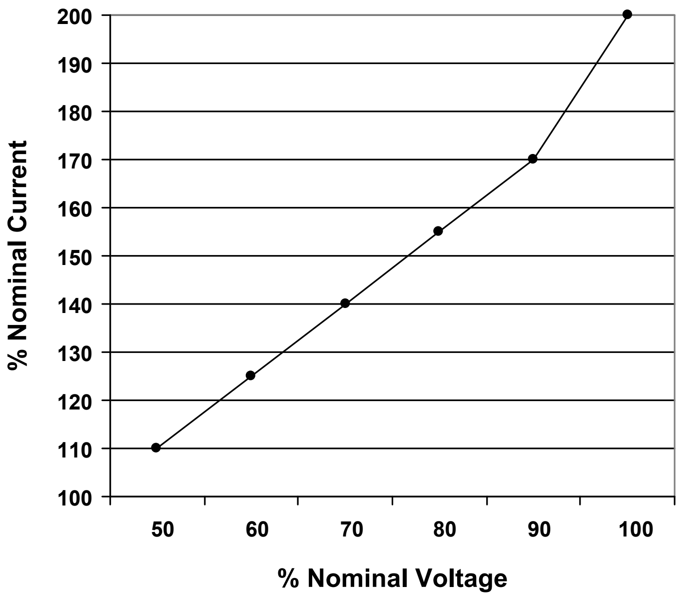
NOTE Option C2 (included in the standard AGC) includes capability curve protection with 12 configurable points. If this simple over-excitation protection is not good enough, use Option C2.

6.8 Voltage-dependent (restraint) over-current

This protection is used when the generator must be tripped due to a fault situation that creates a reduced generator voltage, e.g. a voltage collapse. During the voltage collapse, the generator can only produce part of its usual rating. A short-circuit current during a voltage collapse can even be lower than the nominal current rating.

The protection will be activated based on the over-current set point as a function of the measured voltage on the generator voltage terminals.

The result can be expressed as a curve function where the voltage set points are fixed values and the current set points can be adjusted (menu 1100). This means that if the voltage drops, the over-current set point also drops.



NOTE The voltage values for the six points on the curve are fixed. The current values can be adjusted in the range 50 to 200 %. Voltage and current % values refer to the nominal settings. The timer value can be adjusted in the range 0.1 to 60.0 seconds.

6.9 Decision of measurements

The protection for unbalanced voltage, for example, can be set to either a phase-phase or a phase-neutral measurement. These settings also influence other protections and settings in the AGC. There are three parameters that can change how the measurements are done in the AGC: 1201, 1202 and 1203.

In parameter 1201 it can be set how the voltage measurements should be done for example on generator voltage protection. It can be set to either phase-phase or phase-neutral; by default it is set to phase-phase. When this parameter is set, it should be taken into account how the loads in the application are connected. If many of the loads are connected as phase-neutral, the setting of parameter 1201 should be set to phase-neutral. On a generator controller it will be the voltage measurements on the generator side of a breaker, and on a mains controller it will be the voltage measurements on the mains feeder side of the mains breaker.

Parameter 1201 influences	
1150, 1160	Generator over-voltage protection 1 and 2.
1170, 1180, 1190	Generator under-voltage protection 1, 2 and 3.
1510	Generator unbalanced voltage protection.
1660, 1700	Mains time-dependent under-voltage 1 and 2 (measured on mains feeder side of mains breaker, only in mains controllers).

Parameter 1202 is similar to 1201. It is also considering how the measurements should be made. But this parameter refers to the other voltage measurements. On a generator controller it will be the busbar voltage measurements, and on a mains controller it will be the voltage measurements after the mains breaker. This parameter can also be set to phase-phase measurement or phase-neutral measurement.

Parameter 1202 influences	
1270, 1280, 1290, 1940	Busbar over-voltage protection 1, 2, 3 and 4.
1300, 1310, 1320, 1330, 1950	Busbar under-voltage protection 1, 2, 3, 4 and 5.
1620	Busbar unbalanced voltage protection.

Parameter 1202 influences	
1660, 1700	Busbar time-dependent over-voltage 1 and 2 (measured on busbar side of generator breaker, only in generator controllers).
7480, 7490	Busbar over-voltage average protection 1 and 2.

Parameter 1203 refers to the current measurement as described earlier in this chapter, under "Unbalanced current".

Parameter 1203 influences	
1500	Unbalanced current 1.
1710	Unbalanced current 2.

7. PID regulator for governor and AVR

7.1 Description of PID controller

The AGC includes a PID controller for governor and AVR regulation. It consists of a proportional regulator, an integral regulator and a derivative regulator. The PID controller is able to eliminate the regulation deviation and can easily be tuned in.

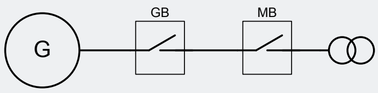
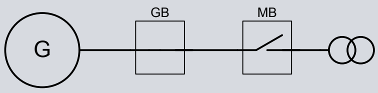
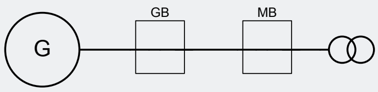
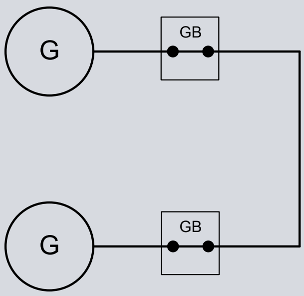
More information
See **General Guidelines for Commissioning**.

7.2 Controllers

There are three controllers for the governor control and three controllers for the AVR control.

Controller	GOV	AVR	Comment
Frequency	●		Controls the frequency
Power	●		Controls the power
P load sharing	●		Controls the active power load sharing
Voltage		●	Controls the voltage
VAr		●	Controls the power factor
Q load sharing	●	●	Controls the reactive power load sharing

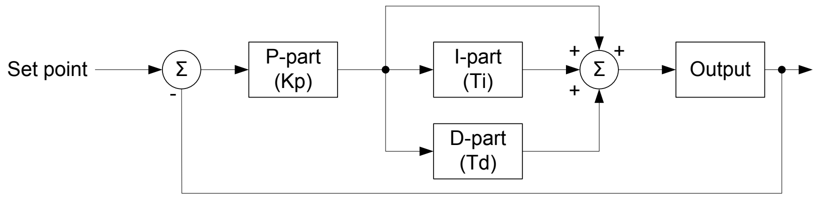
The table below indicates when each of the controllers is active. This means that the controllers can be tuned in when the shown running situations are present.

Governor			AVR			Schematic
Frequency	**Power**	**P LS**	**Voltage**	**VAr**	**Q LS**	
●			●			
●			●			
	●			●		
		●			●	

NOTE The load sharing mode depends on option G5 (power management) and whether hardware option M12 is installed (for analogue load sharing).

7.3 Principle drawing

The drawing below shows the basic principle of the PID controller.



$$PID(s) = Kp \cdot \left(1 + \frac{1}{Ti \cdot s} + Td \cdot s\right)$$

As illustrated in the above drawing and equation, each regulator (P, I and D) gives an output which is summarised to the total controller output.

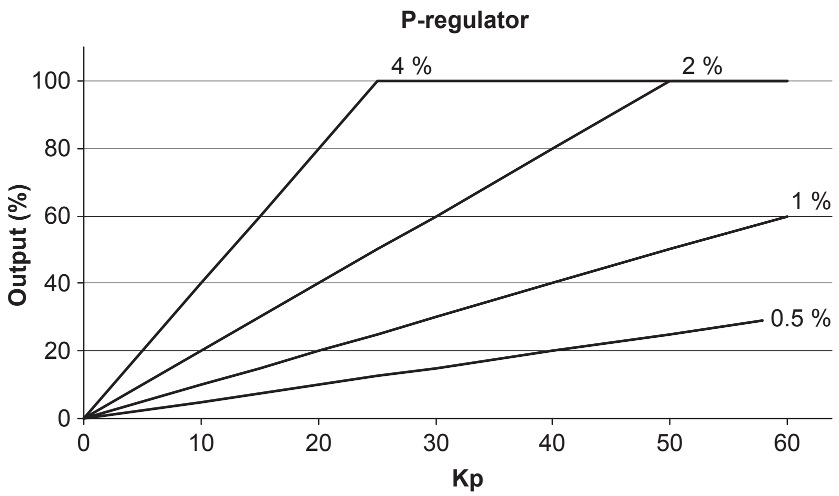
The adjustable settings for the PID controllers in the AGC are:

- Kp: The gain for the proportional part.
- Ti: The integral action time for the integral part.
- Td: The derivative action time for the derivative part.

7.4 Proportional regulator

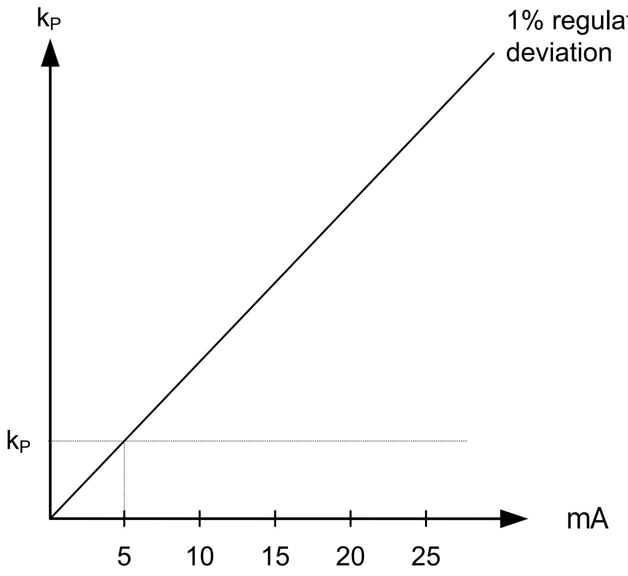
When the regulation deviation occurs, the proportional part will cause an immediate change of the output. The size of the change depends on the gain Kp.

The diagram shows how the output of the P regulator depends on the Kp setting. The change of the output at a given Kp setting will be doubled if the regulation deviation doubles.



7.4.1 Speed range

Because of the characteristic above it is recommended to use the full range of the output to avoid an unstable regulation. If the output range used is too small, a small regulation deviation will cause a rather big output change. This is shown in the drawing below.

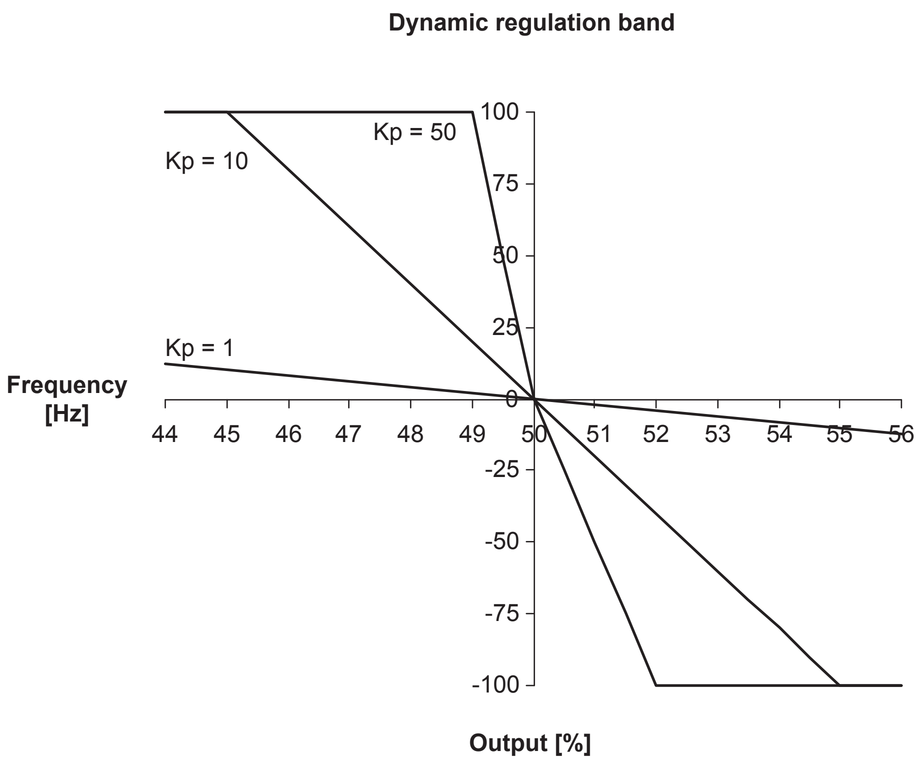


A 1% regulation deviation occurs. With the Kp setting adjusted, the deviation causes the output to change 5 mA. The table shows that the output of the AGC changes relatively much if the maximum speed range is low.

Max. speed range	Output change		Output change in % of max. speed range
10 mA	5 mA	5/10*100%	50
20 mA	5 mA	5/20*100%	25

7.4.2 Dynamic regulation area

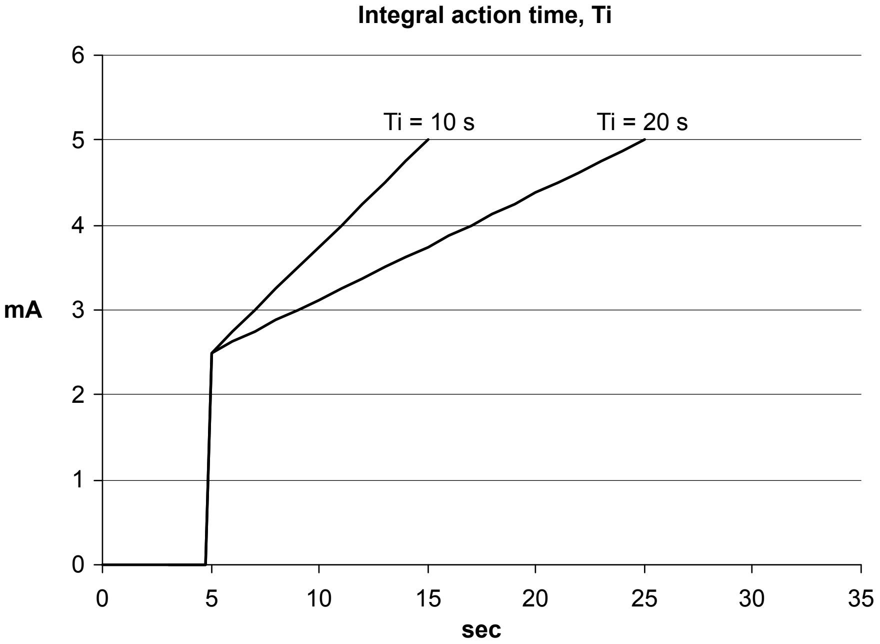
The drawing below shows the dynamic regulation area at given values of Kp. The dynamic area gets smaller if the Kp is adjusted to a higher value.



7.4.3 Integral regulator

The main function of the integral regulator is to eliminate offset. The integral action time Ti is defined as the time the integral regulator uses to replicate the momentary change of the output caused by the proportional regulator.

In the drawing below the proportional regulator causes an immediate change of 2.5 mA. The integral action time is then measured when the output reaches 2 x 2.5 mA = 5 mA.



As shown in the drawing, the output reaches 5 mA twice as fast at a Ti setting of 10 s than with a setting of 20 s.

The integrating function of the I-regulator is increased if the integral action time is decreased. This means that a lower setting of the integral action time Ti results in a faster regulation. The integral action time, Ti, must not be too low. This will make the regulation hunt similar to a too high proportional action factor, Kp.

NOTE If Ti is 0 s, the I-regulator is OFF.

7.4.4 Derivative regulator

The main purpose of the derivative regulator (D-regulator) is to stabilise the regulation, thus making it possible to set a higher gain and a lower integral action time Ti. This will make the overall regulation eliminate deviations much faster.

In most cases, the derivative regulator is not needed. However, for very precise regulation situations, for example, static synchronisation, it can be very useful.

The output from the D-regulator can be explained with the equation:

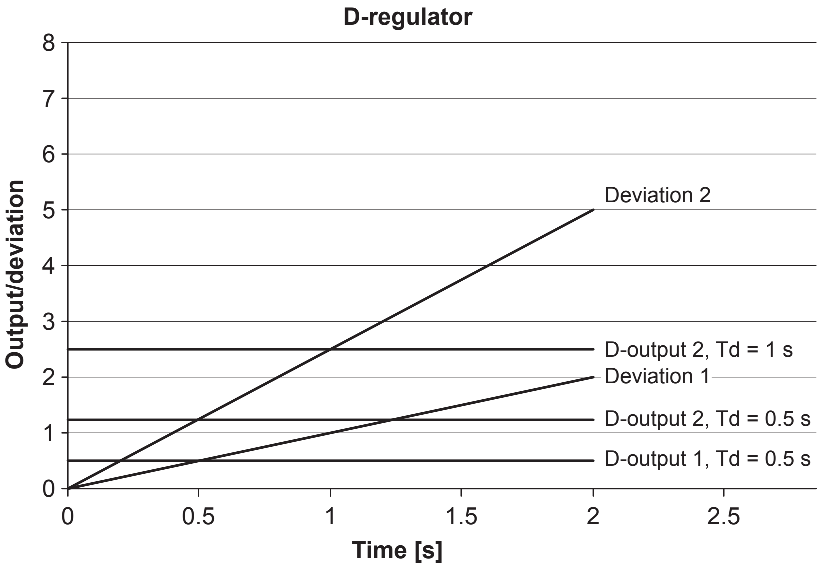
$$D = Td \cdot Kp \cdot \frac{de}{dt}$$

- D = Regulator output
- Kp = Gain
- de/dt = Slope of the deviation (how fast does the deviation occur)

This means that the D-regulator output depends on the slope of the deviation, the Kp and the Td setting.

Example

In the following example it is assumed that Kp = 1.



- Deviation 1: A deviation with a slope of 1.
- Deviation 2: A deviation with a slope of 2.5 (2.5 times bigger than deviation 1).
- D-output 1, Td=0.5 s: Output from the D-regulator when Td=0.5 s and the deviation is according to Deviation 1.
- D-output 2, Td=0.5 s: Output from the D-regulator when Td=0.5 s and the deviation is according to Deviation 2.
- D-output 2, Td=1 s: Output from the D-regulator when Td=1 s and the deviation is according to Deviation 2.

The example shows that the bigger deviation and the higher Td setting, the bigger output from the D-regulator. Since the D-regulator is responding to the slope of the deviation, it also means that when there is no change the D-output will be zero. The derivative action time, Td, must not be too high. This will make the regulation hunt similar to a too high proportional action factor, Kp.

NOTE If the Td is 0 s, the D-regulator is OFF.

7.5 Load share controller

The load share controller is used in whenever load sharing mode is activated. The load share controller is a PID controller similar to the other controllers in the system and it takes care of frequency control as well as power control.

Adjustment of the load share controller is done in menu 2540 (analogue control) or 2590 (relay control).

The primary purpose of the PID controller is always frequency control because frequency is variable in a load sharing system as well as the power on the individual generator. Since the load sharing system requires power regulation as well, the PID controller can be affected by the power regulator. For this purpose a so-called weight factor is used (P_{WEIGHT}).

The regulation deviation from the power regulator can therefore have great or less influence on the PID controller. An adjustment of 0% means that the power control is switched off. An adjustment of 100% means that the power regulation is not limited by the weight factor. Any adjustment in between is possible.

The difference between adjusting the weight value to a high or low value is the speed at which the power regulation deviation is eliminated. So if a firm load sharing is needed, the weight factor must be adjusted to a higher value than if an easy load sharing is required.

An expected disadvantage of a high weight factor is that when a frequency deviation and a power deviation exist, then hunting could be experienced. The solution to this is to decrease either the weight factor or the parameters of the frequency regulator.

7.6 Synchronising controller

The synchronising controller is used in the AGC whenever synchronising is activated. After a successful synchronisation the frequency controller is deactivated and the relevant controller is activated. This could e.g. be the load sharing controller. The adjustments are made in the menu 2050.

Dynamic synchronising

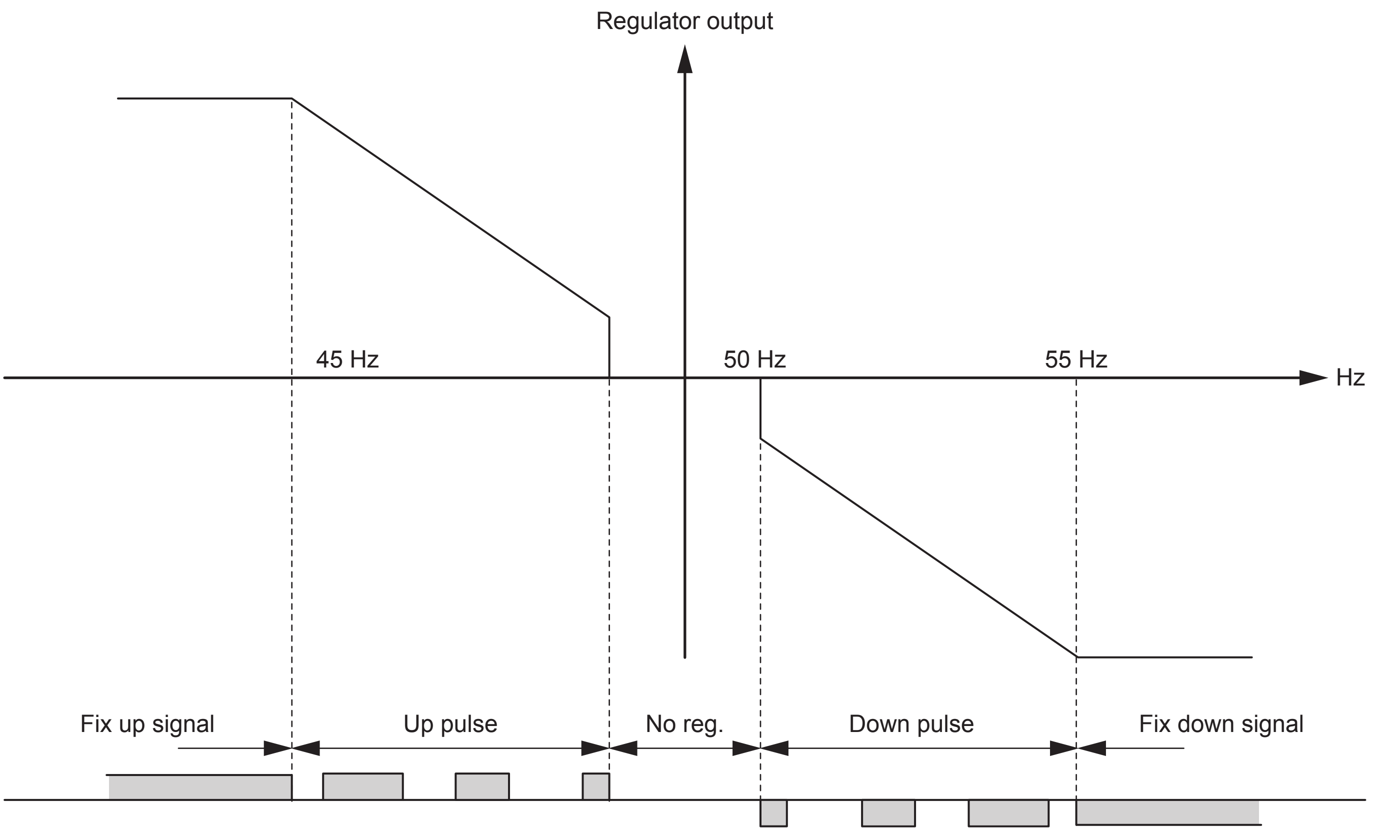
When dynamic synchronising is used, the controller "2050 f_{SYNC} controller" is used during the entire synchronising sequence. One of the advantages of dynamic synchronising is that it is relatively fast. In order to improve the speed of the synchronising further, the generator will be sped up between the points of synchronisation (12 o'clock to 12 o'clock) of the two systems. Normally a slip frequency of 0.1 Hz gives synchronism each 10 seconds, but with this system on a steady engine the time between synchronism is reduced.

Static synchronising

When synchronising is started, the synchronising controller "2050 f_{SYNC} controller" is activated and the generator frequency is controlled towards the busbar/mains frequency. The phase controller takes over when the frequency deviation is so small that the phase angle can be controlled. The phase controller is adjusted in the menu 2070 ("2070 phase controller").

7.7 Relay control

When the relay outputs are used for control purposes, the regulation works like this:



The regulation with relays can be split up into five steps.

#	Range	Description	Comment
1	Static range	Fix up signal	The regulation is active, but the increase relay will be continuously activated because of the size of the regulation deviation.
2	Dynamic range	Up pulse	The regulation is active, and the increase relay will be pulsing in order to eliminate the regulation deviation.
3	Dead band area	No reg.	In this particular range no regulation takes place. The regulation accepts a predefined dead band area in order to increase the lifetime of the relays.

#	Range	Description	Comment
4	Dynamic range	Down pulse	The regulation is active, and the decrease relay will be pulsing in order to eliminate the regulation deviation.
5	Static range	Fix down signal	The regulation is active, but the decrease relay will be continuously activated because of the size of the regulation deviation.

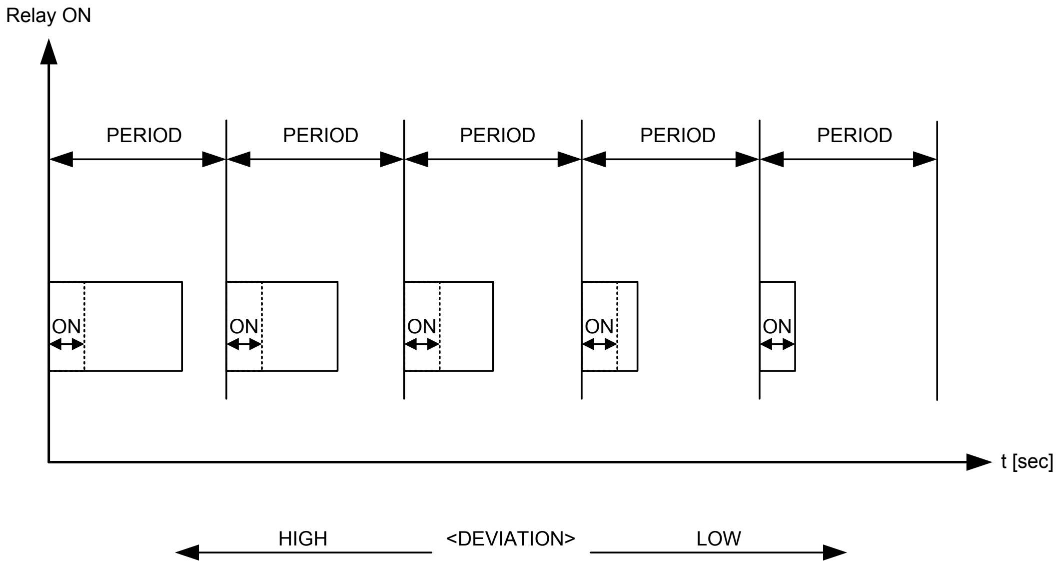
As the drawing indicates, the relays will be fixed ON if the regulation deviation is big, and they will be pulsing if it is closer to the set point. In the dynamic range the pulses get shorter and shorter when the regulation deviation gets smaller. Just before the dead band area the pulse is as short as it can get. This is the adjusted time "GOV ON time"/("AVR ON time"). The longest pulse will appear at the end of the dynamic range (45 Hz in the example above).

7.7.1 Relay adjustments

The time settings for the regulation relays can be adjusted in the control setup. It is possible to adjust the "period" time and the "ON time". They are shown in the drawing below.

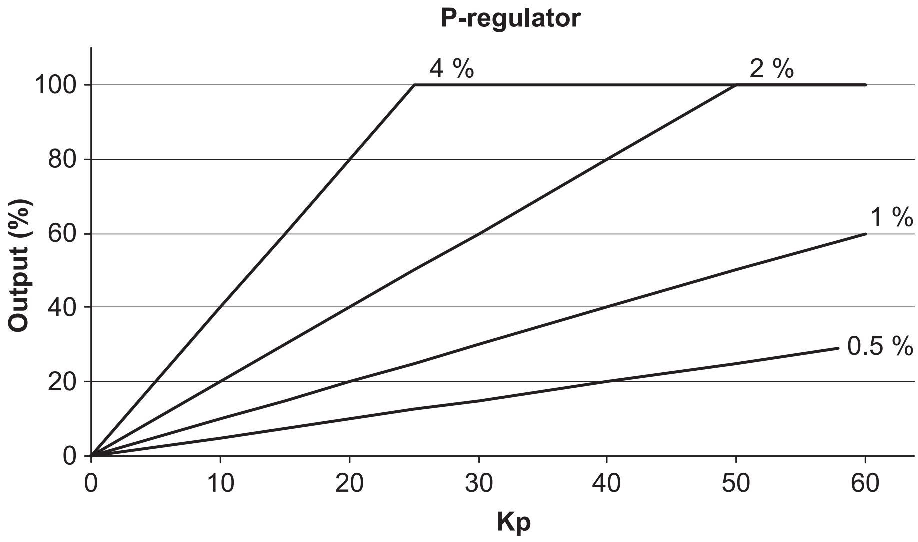
Adjustment	Description	Comment
Period time	Maximum relay time	The time between the beginnings of two subsequent relay pulses.
ON time	Minimum relay time	The minimum length of the relay pulse. The relays will never be activated for a shorter time than the ON time.

As it is indicated in the drawing below, the length of the relay pulse will depend on the actual regulation deviation. If the deviation is big, then the pulses will be long (or a continued signal). If the deviation is small, then the pulses will be short.



7.7.2 Signal length

The signal length is calculated compared to the adjusted period time. In the drawing below the effect of the proportional regulator is shown.



In this example we have a 2 percent regulation deviation and an adjusted value of the Kp = 20. The calculated regulator value of the controller is 4 0%. Now the pulse length can be calculated with a period time = 2500 ms:

e(deviation) / 100 x t(period)
40 / 100 x 2500 = 1000 ms

The length of the period time will never be shorter than the adjusted ON time.

7.8 Droop mode

7.8.1 Principle and setup

Droop mode can be used when a new genset is installed together with existing gensets which operate in droop mode in order to make equal load sharing with the existing gensets. This regulation mode can be used where it is required/allowed that the generator frequency drops with increasing load.

The droop mode parameters can be adjusted between 0-10 % droop. If the value is different from 0 %, the droop percentage will be applied on top of the regulation output of the governor (f) or AVR (U).

Droop regulation parameters

Parameter	Name	Description
2514	f droop	Droop setting for frequency regulator with analogue output
2573	f droop relay	Droop setting for frequency regulator with relay regulation
2644	U droop	Droop setting for voltage regulator with analogue output
2693	U droop relay	Droop setting for voltage regulator with relay regulation

NOTE When using droop mode, the frequency PID (f) and voltage PID (U) is active. If option M12 is present, you must inhibit analogue load sharing.

Activating droop regulation

The following M-Logic commands are used to activate droop regulation. This gives more options to activate the regulation, for example a digital input, an AOP button or an event.

M-Logic command	Description
Output, Command, Act. Frequency droop regulation	Activates the use of frequency droop parameters mentioned above
Output, Command, Act. Voltage droop regulation	Activates the use of voltage droop parameters mentioned above

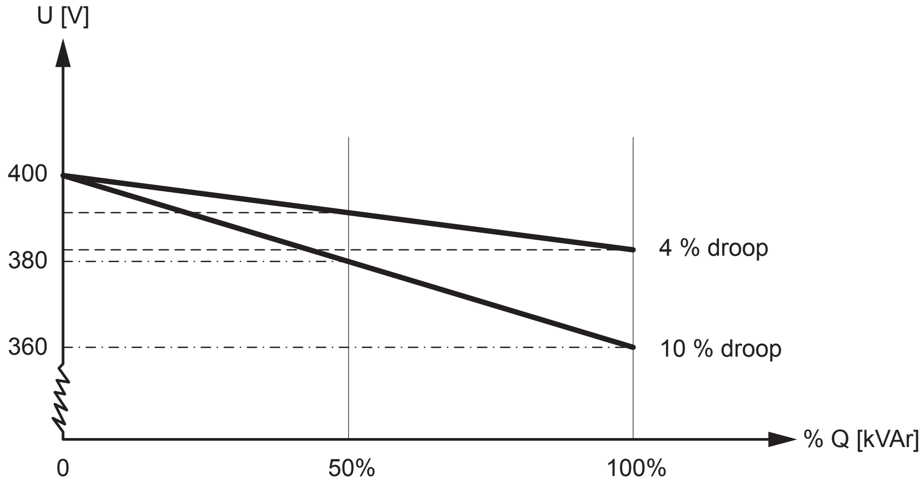
Application configuration

When operating in droop mode, the AGC has to be configured with a Single DG application drawing. This is done through the utility software or with quick setup.

See the utility software help function (F1) for details about application configuration.

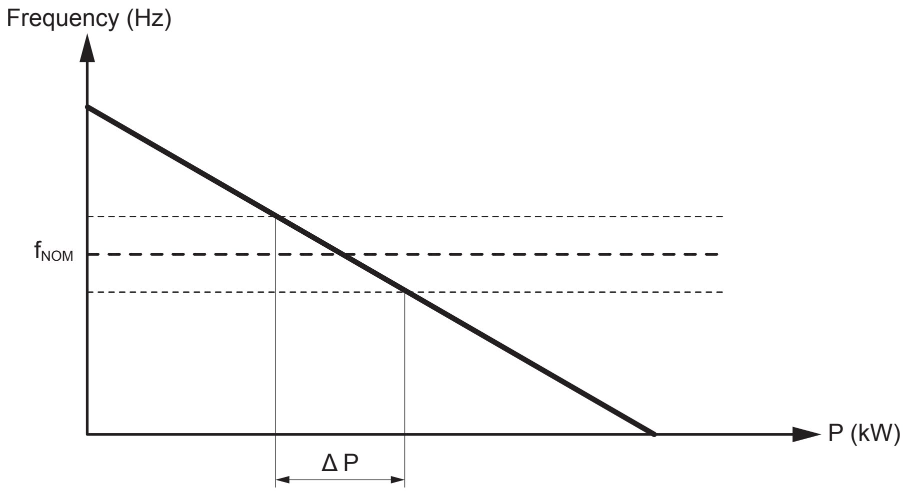
7.8.2 Voltage droop example

The diagram below shows an example for one generator where the voltage droop setting is 4% and 10% in proportion to the reactive power, Q (kVAr). As it is shown in the example, the voltage drops as the load increases. The principle is the same with generators in parallel where the generators will use the droop to share the load and allow the voltage/frequency to drop accordingly.



7.8.3 High droop setting

To illustrate the influence of a high droop setting, the diagram below shows how a frequency variation gives a change in the load, the principle is the same with voltage regulation. The load change is marked as ΔP.

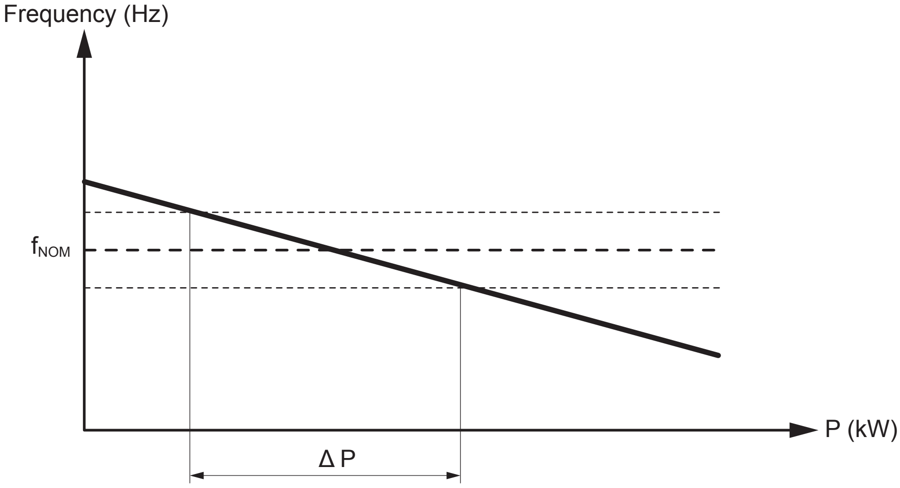


NOTE This can be used if the generator must operate base-loaded.

7.8.4 Low droop setting

To illustrate the influence of a low droop setting, the diagram below shows how a frequency variation gives a change in the load, the principle is the same with voltage droop regulation. The load change is marked as ΔP.

In this diagram, the load change (ΔP) is larger than before. This means that the generator will vary more in loading than with the higher droop setting.



NOTE This can be used if the generator must operate as a peak load machine.

7.8.5 Compensation for isochronous governors

When the genset is equipped with a governor only providing isochronous operation, the droop setting can be used to compensate for the missing droop setting possibility on the governor.

8. Synchronisation

8.1 Synchronisation principles

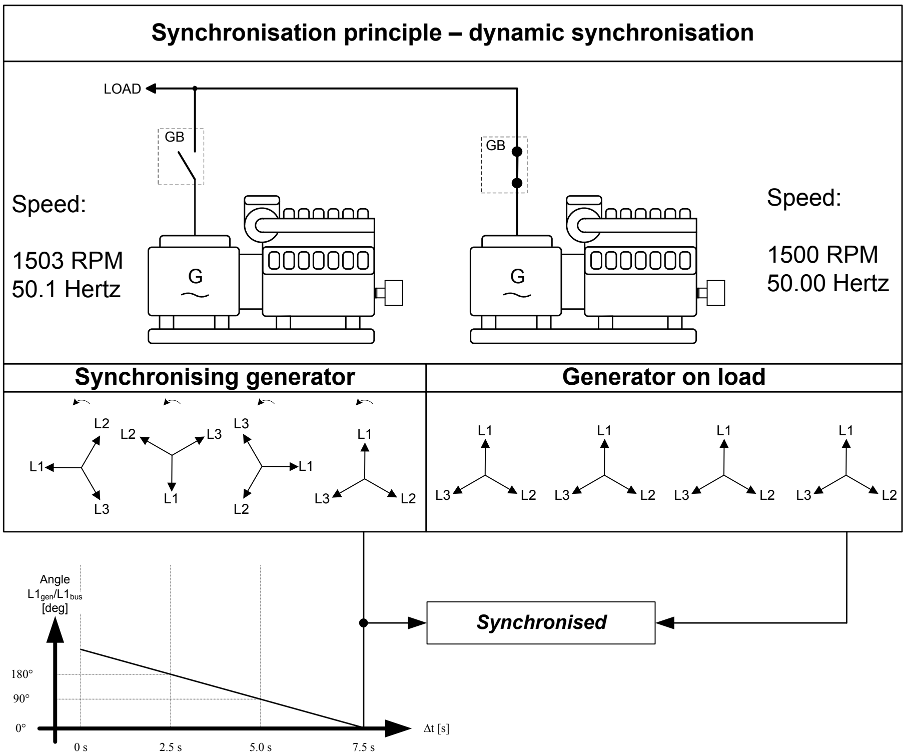
The controller can be used for synchronisation of generator and mains breaker (if installed). Two different synchronisation principles are available, namely static and dynamic synchronisation (dynamic is selected by default). This chapter describes the principles of the synchronisation functions and the adjustment of them.

NOTE In the following, the term "synchronisation" means "*synchronising and closing of the synchronised breaker*".

8.2 Dynamic synchronisation

In dynamic synchronisation, the synchronising genset is running at a different speed than the generator on the busbar. This speed difference is called *slip frequency*. Typically, the synchronising genset is running with a positive slip frequency. This means that it is running with a higher speed than the generator on the busbar. The objective is to avoid a reverse power trip after the synchronisation.

The dynamic principle is illustrated below.



In the example above, the synchronising genset is running at 1503 RPM ~ 50.1 Hz. The generator on load is running at 1500 RPM ~ 50.0 Hz. This gives the synchronising genset a positive slip frequency of 0.1 Hz.

The intention of the synchronising is to decrease the phase angle difference between the two rotating systems. These two systems are the three-phase system of the generator and the three-phase system of the busbar. In the illustration above, phase L1 of the busbar is always pointing at 12 o'clock, whereas phase L1 of the synchronising genset is pointing in different directions due to the slip frequency.

NOTE Of course both three-phase systems are rotating, but for illustrative purposes the vectors for the generator on load are not shown to be rotating. This is because we are only interested in the slip frequency for calculating when to release the synchronisation pulse.

When the generator is running with a positive slip frequency of 0.1 Hz compared to the busbar, the two systems will be synchronised every 10 seconds.

$$t_{SYNC} = \frac{1}{50.1 - 50.0} = 10 \text{ sec.}$$

NOTE See the chapter on PID controllers and the synchronising controllers.

In the illustration above, the difference in the phase angle between the synchronising set and the busbar gets smaller and will eventually be zero. Then the genset is synchronised to the busbar, and the breaker will be closed.

8.2.1 Close signal

The controller always calculates when to close the breaker to get the most accurate synchronisation. This means that the close breaker signal is actually issued before being synchronised (read L1 phases exactly at 12 o'clock).

The breaker close signal will be issued depending on the breaker closing time and the slip frequency (response time of the circuit breaker is 250 ms, and the slip frequency is 0.1 Hz):

- deg $_{CLOSE}$ = 360 × t_{CB} × f_{SLIP}
- deg $_{CLOSE}$ = 360 × 0.250 × 0.1
- deg $_{CLOSE}$ = 9 deg

NOTE The synchronisation pulse is always activated so the closing of the breaker occurs at the 12 o'clock position.

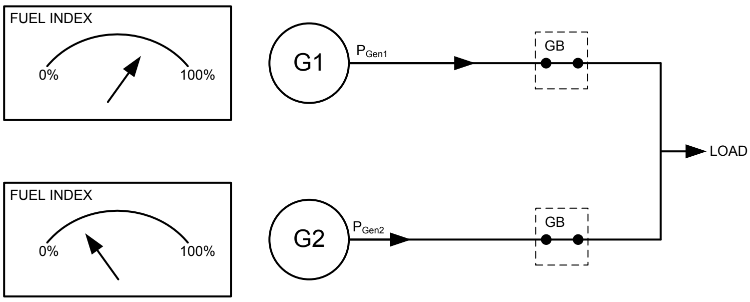
The length of the synchronisation pulse is the response time of the breaker + 20 ms.

8.2.2 Load picture after synchronising

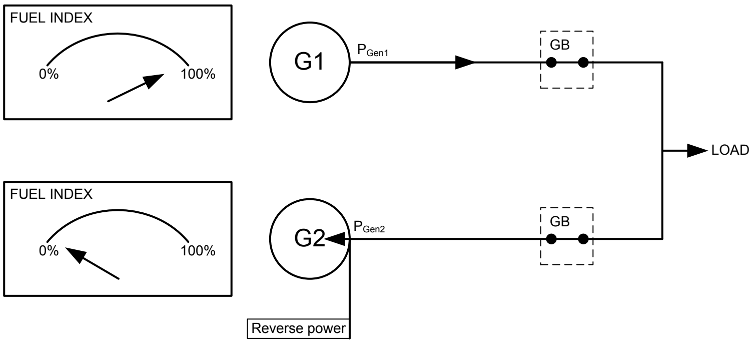
When the incoming genset has closed its breaker, it will take a portion of the load dependent on the actual position of the fuel rack. Illustration 1 below indicates that at a given *positive* slip frequency, the incoming genset will *export* power to the load. Illustration 2 below shows that at a given *negative* slip frequency, the incoming genset will *receive* power from the original genset. This phenomenon is called *reverse power*.

NOTE To avoid nuisance trips caused by reverse power, the synchronising settings can be set up with a positive slip frequency.

POSITIVE slip frequency



NEGATIVE slip frequency



8.2.3 Adjustments

The dynamic synchroniser is selected in menu 2000 Sync. type in the control setup and is adjusted in menu 2020 Synchronisation.

Name	Parameter	Description	Comment
Sync df_{MAX}	2021	Maximum slip frequency	Adjust the maximum positive slip frequency where synchronising is allowed.
Sync df_{MIN}	2022	Minimum slip frequency	Adjust the maximum negative slip frequency where synchronising is allowed.
Sync dU_{MAX}	2023	Maximum voltage difference (+/- value)	The maximum allowed voltage difference between the busbar/mains and the generator.
Sync dU_{MIN}	2024	Minimum voltage difference (+/- value)	The minimum allowed voltage difference between the busbar/ mains and the generator.
Sync t_{GB}	2025	Generator breaker closing time	Adjust the response time of the generator breaker.
Sync t_{MB}	2026	Mains breaker closing time	Adjust the response time of the mains breaker.

The speed of the slip frequency is determined by two settings, "Sync df_{MAX}" and "Sync df_{MIN}". The calculation from the examples below shows why it is important to configure the slip frequency speed correctly.

Example 1

The slip frequency speed of the genset is 0.15 Hz faster than the frequency of the busbar or the grid that the genset is trying to synchronise to.

This means that the phase angle difference between the genset and the busbar or the grid will decrease and eventually be within the GB closing window.

Example 2

This means that the phase angle difference between the genset and the busbar or the grid will not decrease. In this example, the genset will never reach the GB closing window because it will never catch up on the grid or the busbar.

Explanation: $\frac{df_{MAX} + df_{MIN}}{2}$ = *Slip frequency speed*

Example 1: $\frac{0.3\ Hz + 0.0\ Hz}{2} = +0.15\ Hz$

Example 2: $\frac{0.3\ Hz + (-0.3\ Hz)}{2} = +0\ Hz$

It is obvious that this type of synchronisation is able to synchronise relatively fast because of the adjusted minimum and maximum slip frequencies. This actually means that when the controller is aiming to control the frequency towards its set point, synchronising can still occur as long as the frequency is within the limits of the slip frequency adjustments.

NOTE Dynamic synchronisation is recommended where fast synchronisation is required, and where the incoming gensets are able to take load just after the breaker has been closed.

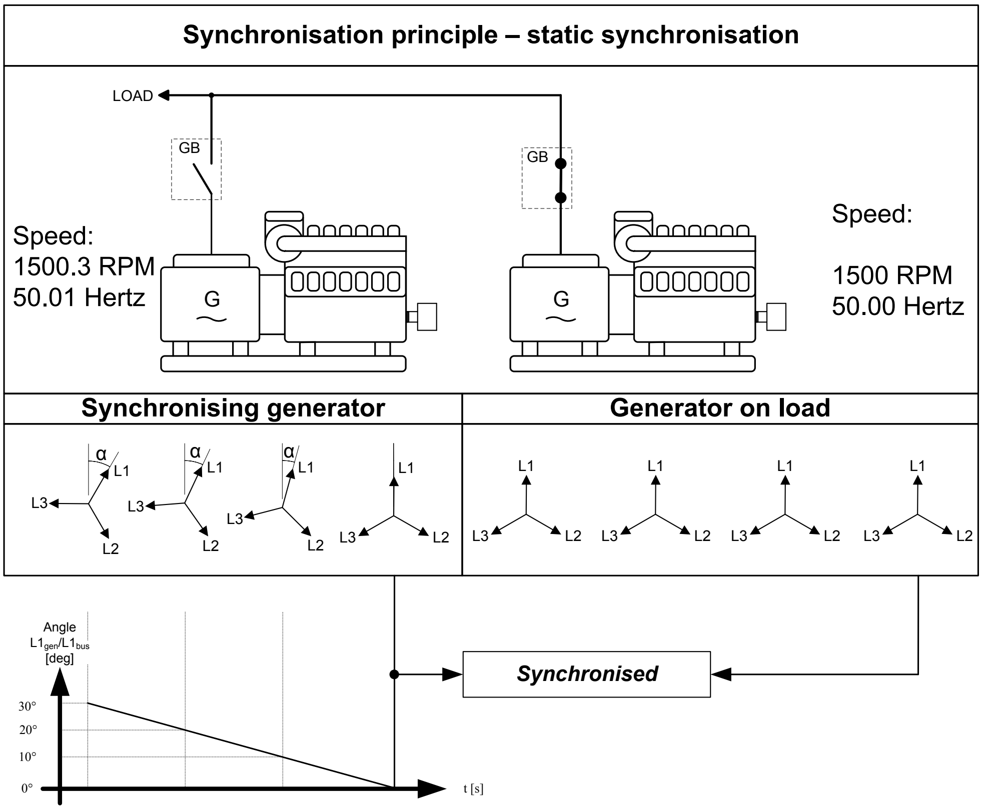
NOTE Static and dynamic synchronisation can be switched using M-Logic.

8.3 Static synchronisation

In static synchronisation, the synchronising genset is running very close to the same speed as the generator on the busbar. The aim is to let them run at exactly the same speed and with the phase angles between the three-phase system of the generator and the three-phase system of the busbar matching exactly.

NOTE It is not recommended to use static synchronisation when relay regulation outputs are used. This is due to the slower regulation with relay outputs.

The static principle is illustrated below.



8.3.1 Phase controller

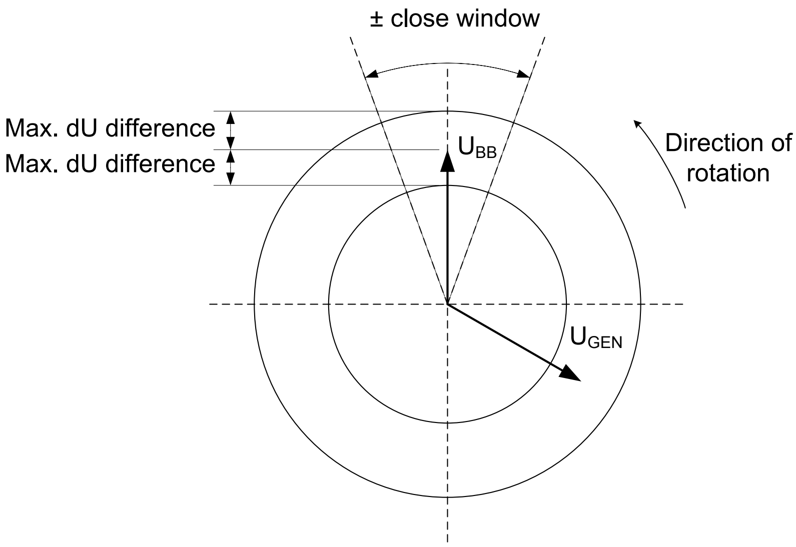
When the static synchronisation is used and the synchronising is activated, the frequency controller will bring the genset frequency towards the busbar frequency. When the genset frequency is within 50 mHz of the busbar frequency, the phase controller takes over. This controller uses the angle difference between the generator system and the busbar system as the controlling parameter.

This is illustrated in the example above where the phase controller brings the phase angle from 30 deg. to 0 deg.

8.3.2 Close signal

The close signal will be issued when phase L1 of the synchronising generator is close to the 12 o'clock position compared to the busbar which is also in 12 o'clock position. It is not relevant to use the response time of the circuit breaker when using static synchronisation, because the slip frequency is either very small or non-existing.

To be able to get a faster synchronisation, a "close window" can be adjusted. The close signal can be issued when the phase angle U_{GENL1}-U_{BBL1} is within the adjusted set point. The range is +/-0.1-20.0 deg. This is illustrated in the drawing below.



The synchronisation pulse is sent dependent on the settings in menu 2030. It depends on whether it is the GB or the MB that is to be synchronised.

8.3.3 Load picture after synchronisation

The synchronised genset will not be exposed to an immediate load after the breaker closure if the maximum df setting is adjusted to a low value. Since the fuel rack position almost exactly equals what is required to run at the busbar frequency, no load jump will occur.

If the maximum df setting is adjusted to a high value, then the observations in the section about "dynamic synchronisation" must be observed.

After the synchronising, the controller will change the set point according to the requirements of the selected genset mode.

NOTE Static synchronisation is recommended where a slip frequency is not accepted. For example, if several gensets synchronise to a busbar with no load groups connected.

NOTE Static and dynamic synchronisation can be switched using M-Logic.

8.3.4 Adjustments

The following settings must be adjusted if the static synchroniser is selected in menu 2000:

Setting	Description	Comment
2031 Maximum df	The maximum allowed frequency difference between the busbar/mains and the generator.	+/- value.
2032 Maximum dU	The maximum allowed voltage difference between the busbar/mains and the generator.	+/- value related to the nominal generator voltage.
2033 Closing window	The size of the window where the synchronisation pulse can be released.	+/- value.
2034 Static sync	Minimum time inside the phase window before sending a close command.	

Setting	Description	Comment
2035 Static type GB	"Breaker" or "Infinite sync" can be chosen.	"Infinite sync" will close the MB to the busbar and run the generator in sync with the mains. The GB is not allowed to close.
2036 Static type MB	"Breaker" or "Infinite sync" can be chosen.	"Infinite sync" will close the GB to the busbar and run the generator in sync with the mains. The MB is not allowed to close.
2061 Phase K_P	Adjustment of the proportional factor of the PI phase controller.	Only used during analogue regulation output.
2062 Phase K_I	Adjustment of the integral factor of the PI phase controller.	
2070 Phase K_P	Adjustment of the proportional factor of the PI phase controller.	Only used during relay regulation output.

8.4 Close before excitation

You can configure the AGC to start up the genset with the excitation switched off. When the gensets are started up, the breakers are closed and the excitation is started. Alternatively, you can close the breaker before the engine is started. This function is called *Close Before Excitation* (CBE).

For *close before excitation*, the gensets can be ready for the load very quickly. All of the gensets are connected to the busbar as soon as they are started. As soon as the excitation is switched on, the gensets are ready for operation. This is faster than the normal synchronising (where the breakers are not closed until the generators are synchronised, which takes some time to achieve).

The *close before excitation* function can also be used if the load requires a *soft* start. For example, when the gensets connect to a transformer.

As soon as the excitation is activated, the generators equalise the voltage and frequency. When the excitation is activated, the regulators of the AGC are switched on after an adjustable delay.

The function can be used in a single AGC, and also in AGCs with option G5.

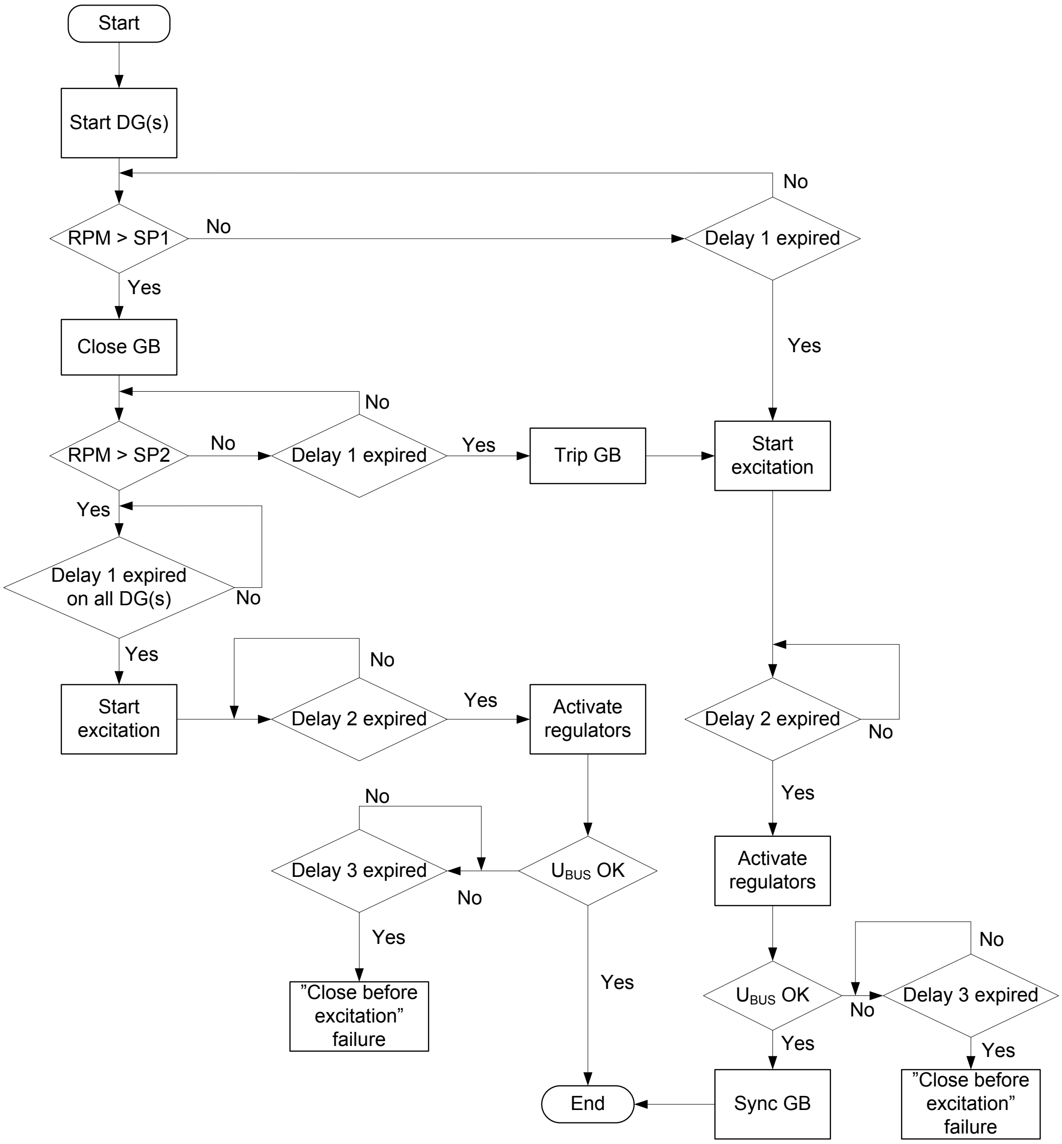
NOTE The excitation must be increased slowly when this function is used.
NOTE This function can only be used with a magnetic pickup (MPU) or EIC speed signal.

The principle is described in the flowcharts below.

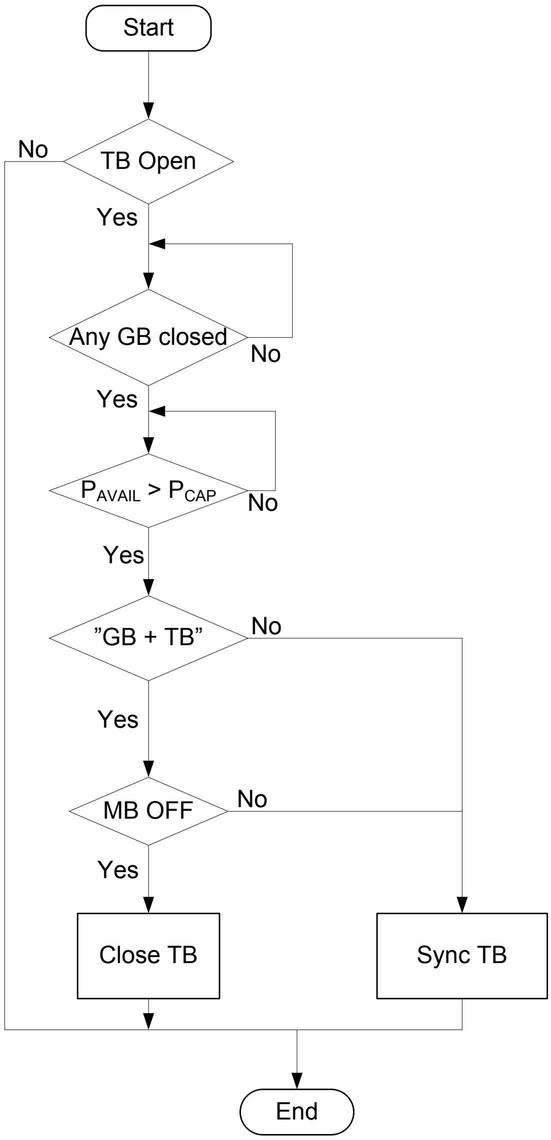
Flowchart abbreviations

- Delay 1 = Parameter 2252 (CBE break. lim.)
- Delay 2 = Parameter 2262 (CBE softstart)
- Delay 3 = Parameter 2271 (Cl.bef.exc.fail)
- SP1 = Parameter 2251 (Close bef. exc.)
- SP2 = Parameter 2263 (Exc. start RPM)

8.4.1 Flowchart 1, GB handling



8.4.2 Flowchart 2, TB handling (option G5)

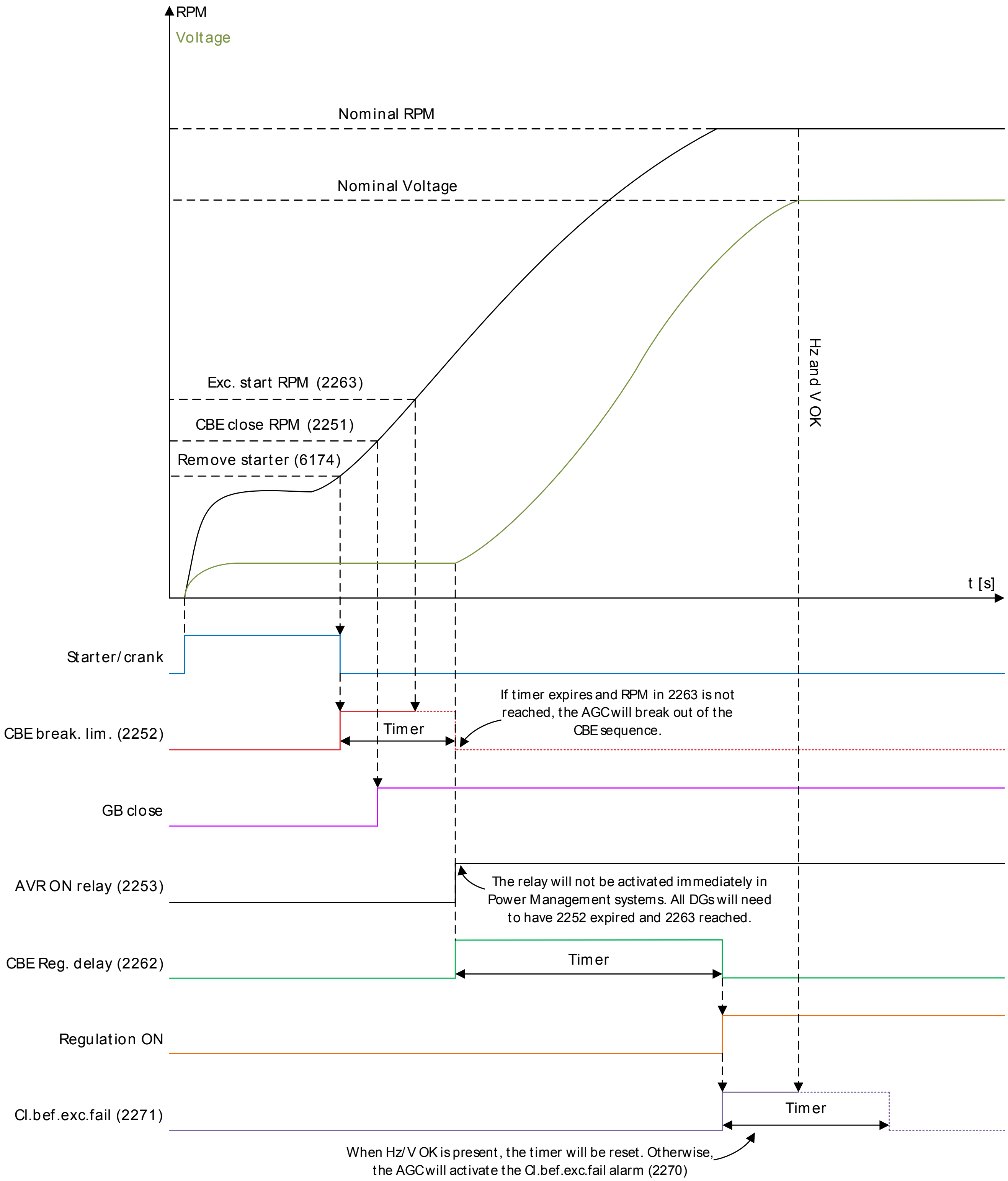


8.4.3 Genset start actions

The start sequence of the AGC is changed by close before excitation. The following parameters are relevant:

Parameter	Name	Comment
2251	Close bef. exc. - Set point	This is the RPM set point for breaker closing. The generator breaker will close at the configured level. The range is 0-4000 RPM. If it is 0, the breaker will be closed when the start command is given. In the example below the setting is 400 RPM.
	Enable	Enable close before excitation.
2252	CBE break. lim.	The genset must reach the set point (parameter 2263) within this time. When the timer expires and the RPM is above the set point, excitation is started. If the RPM is below the set point, the GB is tripped.
2253	CBE AVR relay	Select a relay output to use to start the excitation. In the *I/O & Hardware setup*, for the selected relay, under *Alarm*, select *M-Logic / Limit relay*. For the best CBE performance, use relay 5, 8 or 11.

NOTE The relay used for close before excitation must not be used for anything else.



8.4.4 Breaker sequence

The close before excitation function can be used in these applications:

1. AGC single genset plant
2. AGC power management plant - no tie breaker present
3. AGC power management plant - tie breaker present
   - Select in parameter 2261 whether only the generator breaker must be closed, or both the generator breaker and also the tie breaker.

The breaker sequence adjustments are the following:

Parameter	Name	Comment
2261	Breaker seq.	Select breakers to close: *Close GB* or *Close GB + TB*.
2262	CBE softstart	The period from when the excitation is started, until the regulation is activated. Alarms with the inhibit *Not run status* can be activated after this timer has expired.
2263	Exc. start RPM	The minimum RPM for the excitation to start.
2264	Volt. discharge	This timer delays the closing of the GB after removing excitation. The delay allows the voltage of the generator discharge, so that only remanence voltage is present when the GB is closed.

8.4.5 Close before excitation – additional control parameters

If the application has been configured to use Close Before Excitation (CBE) during the genset start, the controller can do additional things to handle the sequence correctly.

If, for example, the application is backup power (AMF), you can select what the controller should do during cooldown. For example, if a new start request comes during cooldown (rerun), the genset(s) can do the CBE sequence again without stopping the genset(s).

Excitation control during cooldown

In parameter 2266 (ExcCtrl cooldwn), you can select how the controller should react during cooldown:

- **Excitation follow U busbar** (default): If there is voltage on the busbar during the genset cooldown, the excitation is ON. If the voltage on the busbar disappears, the excitation is shut OFF.
- **Excitation constant ON**: The excitation is ON until the genset stops or a new start request comes. This can be useful if the genset voltage drives the genset fans.
- **Excitation constant OFF**: The excitation is switched OFF as soon as the GB is open during cooldown. This can be useful if the genset mechanically pulls the genset fans. Then the genset can rerun faster.

NOTE The parameter is not shared between the gensets.

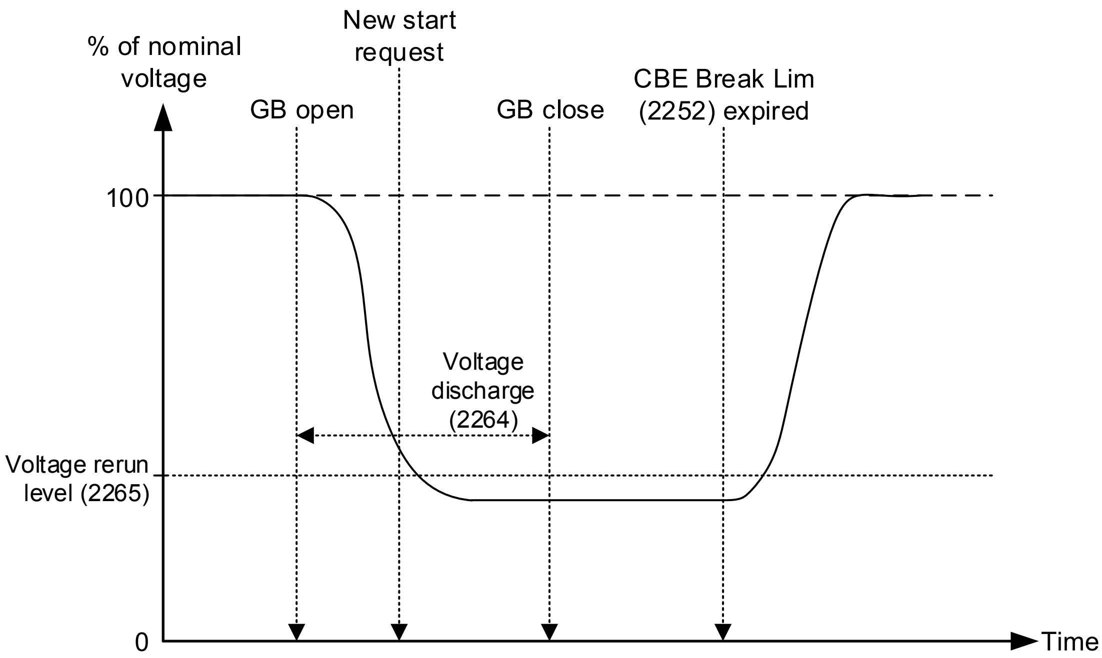
Voltage rerun level

In parameter 2265 (Volt. rerun levl), select how low the voltage must be, before the controller can close the breaker during the rerun. If the voltage is not below the voltage rerun level before the voltage discharge timer (parameter 2264) has expired, the genset is excluded from the CBE rerun sequence.

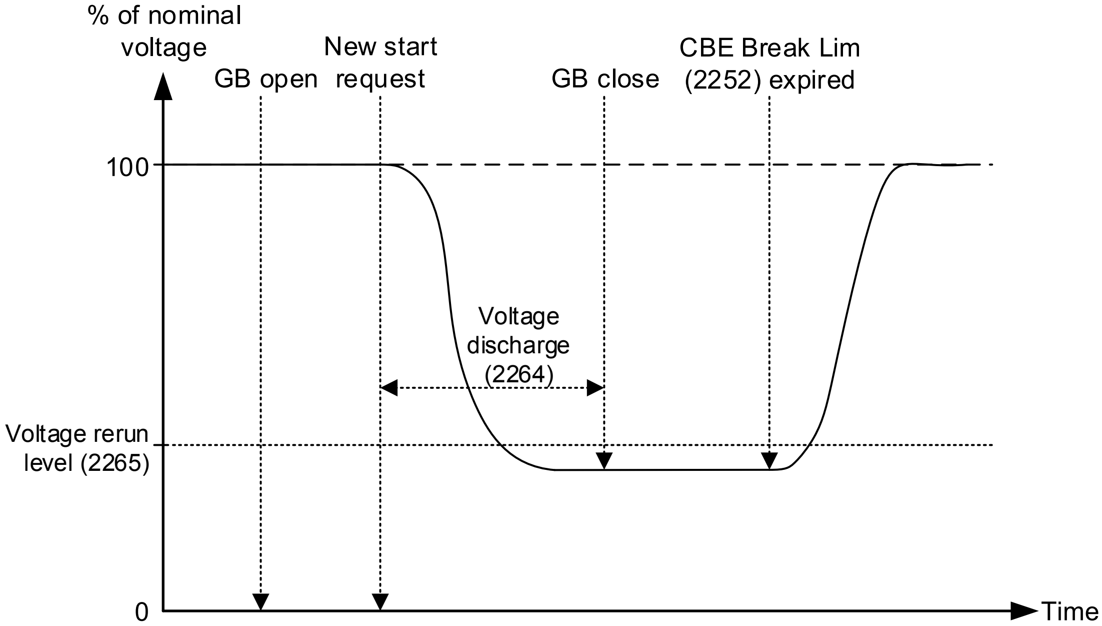
Parameter	Name	Range	Default	Note
2265	Voltage rerun level	30 to 100 %	30 %	The parameter is not shared between gensets.

Voltage discharge timer

The voltage discharge timer (parameter 2264) determines how much time is required from when the excitation is removed until the voltage is below the voltage rerun level. The voltage discharge timer can be started by a new start request or when the generator breaker opens. The reactions depend on the selection for excitation control during cooldown. The two rerun sequence examples are shown below.



In the diagram above, the excitation is shut off as soon as the breaker is opened. Soon after the breaker is opened, a new start request appears. The controller delays closing the GB until the voltage discharge timer has expired.



In the diagram above, the excitation is ON during cooldown. When a new start request is made, the excitation is shut off. When the excitation is shut off, the voltage discharge timer starts.

The first example is the fastest, because the excitation is already off when the start request appears. If the new start request appeared a little later, the voltage discharge timer could already have expired. This means that the generator breaker could close very shortly after the new start request.

Parameter	Name	Range	Default	Note
2264	Volt. discharge	1.0 to 20.0 s	5.0 s	The parameter is not shared between gensets.

8.4.6 Close before excitation alarms

Close before excitation failure

If the genset start fails, the controller activates the *Cl.bef.exc.fail* alarm (menu 2270).

To use close before excitation when the genset controller does not control the voltage, disable the alarm.

Close before excitation re-run failure

If the rerun does not succeed within the configured time, the controller activates the *CBE Re-run fail* alarm (menu 2230).

Frequency or voltage failure

If there is no excitation, the controller will not activate the *Hz/V failure* alarm (menu 4560) during a CBE cooldown.

8.5 Separate synchronising relay

When the AGC gives the synchronising command, then the relays on terminal 17/18/19 (generator breaker) and terminal 11/12/13 (mains breaker) will activate, and the breaker must close when this relay output is activated.

This default function can be modified using a digital input and extra relay outputs depending on the required function. The relay selection is made in the menu 2240, and the input is selected in the input settings in the utility software.

The table below describes the possibilities.

Digital input	Relay selected Two relays used	Relay not selected One relay used
Not used	**Synchronising** The breaker ON relay and the sync. relay activate at the same time when synchronising is OK. **Blackout closing** The breaker ON relay and the sync. relay activate at the same time when the voltage and frequency are OK.	**Synchronising** The breaker ON relay activates when synchronising is OK. **Blackout closing** The breaker ON relay activates when the voltage and frequency are OK. **DEFAULT selection**
Low	**Synchronising** Not possible. **Blackout closing** The breaker ON relay and the sync. relay activate at the same time when the voltage and frequency are OK.	**Synchronising** Not possible. **Blackout closing** The breaker ON relay activates when the voltage and frequency are OK.
High	**Synchronising** The relays will activate in two steps when the synchronising is selected: 1. Breaker ON relay activates. 2. When synchronised the sync. relay activates. **See note below!** **Blackout closing** The breaker ON relay and the sync. relay activate at the same time when the voltage and frequency are OK.	**Synchronising** Not possible. **Blackout closing** The breaker ON relay activates when the voltage and frequency are OK.

DANGER!

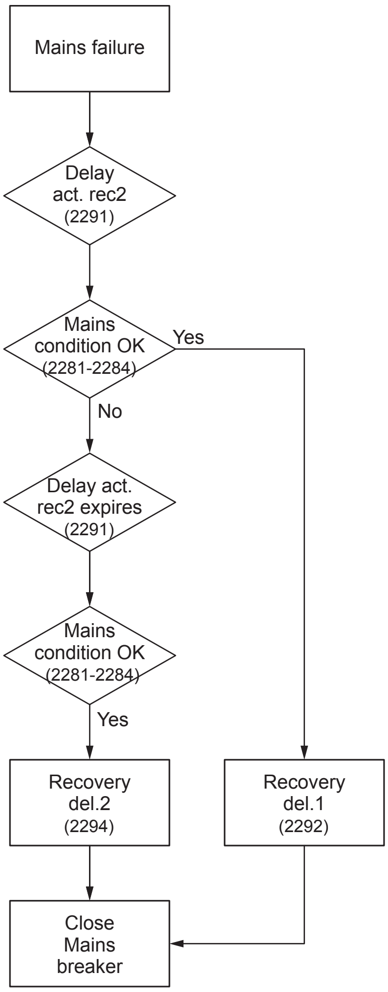
Unsynchronised breaker closing

When two relays are used together with the separate sync. input, then the breaker ON relay is activated as soon as the GB ON/synchronising sequence is activated. Make sure that the GB ON relay cannot close the breaker before the sync. signal is activated by the sync. relay.

NOTE The relay selected for this function must have the *Limits* function. This is configured in the I/O setup.

8.6 Inhibit conditions before synchronising mains breaker

This function is used to inhibit the synchronising of the mains breaker after blackout. After blackout, the timer in menu 2291 (*Delay activate recovery 2*) will start to run, and if the mains voltage and frequency are inside the limits (2281/2282/2283/2284) before the timer runs out, the short interruption timer (menu 2292 *Recovery del. 1*) will be started. When the timer has run out, the synchronising of the MB will start.



If the *Delay activate recovery 2* timer runs out, the long interruption timer (menu 2294 *Recovery del. 2*) will start to run.

Example 1: Recovery timer 1 (short interruption timer)

- Menu 2291 = 3 s
- Menu 2292 = 5 s

That means: if the short interruption timer is set to ≤ 3 s, and the grid is back and voltage and frequency are inside the acceptable range stated above, then after 5 s the MB can be closed.

Example 2: Recovery timer 2 (long interruption timer)

- Menu 2291 = 3 s
- Menu 2294 = 60 s

The long interruption timer will allow the MB to reconnect as soon as the mains voltage and frequency have been uninterrupted within the timer setting in menu 2294 (*Recovery del. 2*). Then the MB can be closed.

NOTE The inhibit parameters for synchronising the MB are disabled by default.

9. Additional functions

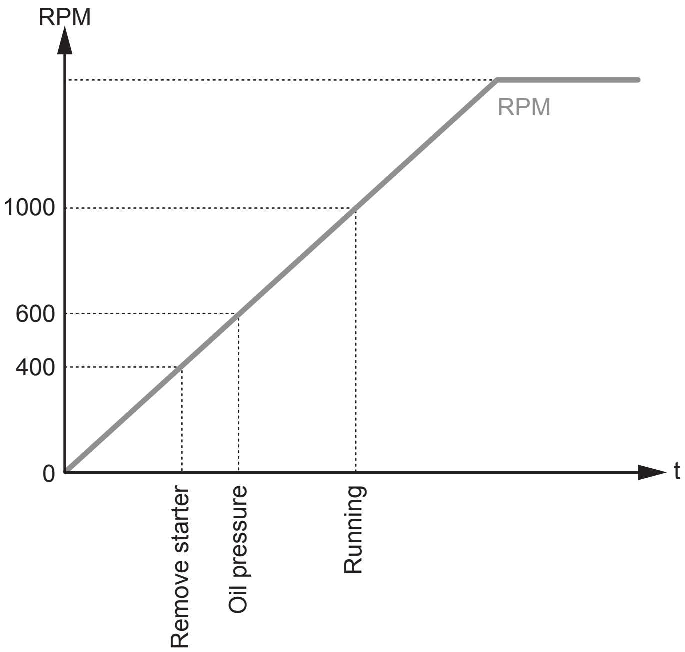
9.1 Start functions

The controller will start the genset when the start command is given. The start sequence is deactivated when the remove starter event occurs or when the running feedback is present.

The reason for having two possibilities to deactivate the start relay is to be able to delay the alarms with run status.

If it is not possible to activate the run status alarms at low revolutions, the remove starter function must be used.

An example of a critical alarm is the oil pressure alarm. Normally, it is configured according to the shutdown fail class. But if the starter motor has to disengage at 400 RPM, and the oil pressure does not reach a level above the shutdown set point before 600 RPM, then, obviously, the genset would shut down if the specific alarm was activated at the preset 400 RPM. In that case, the running feedback must be activated at a higher number of revolutions than 600 RPM.

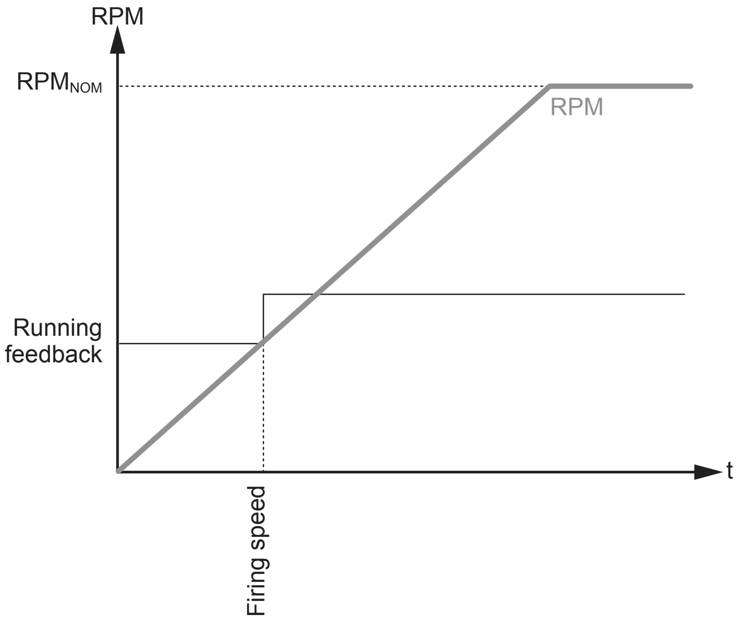


9.1.1 Digital feedbacks

If an external running relay is installed, then the digital control inputs for running detection or remove starter can be used.

Running feedback

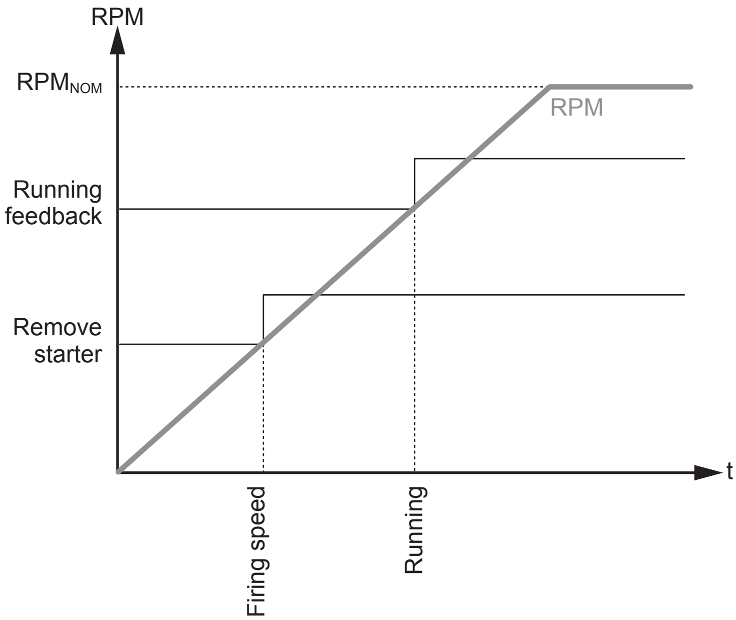
When the digital running feedback is active, the start relay is deactivated and the starter motor will be disengaged.



The diagram illustrates how the digital running feedback (terminal 117) is activated when the engine has reached its firing speed.

Remove starter

When the digital remove starter input is present, the start relay is deactivated and the starter motor will be disengaged. The remove starter input must be configured from a number of available digital inputs.



The diagram illustrates how the remove starter input is activated when the engine has reached its firing speed. At the running speed, the digital running feedback is activated.

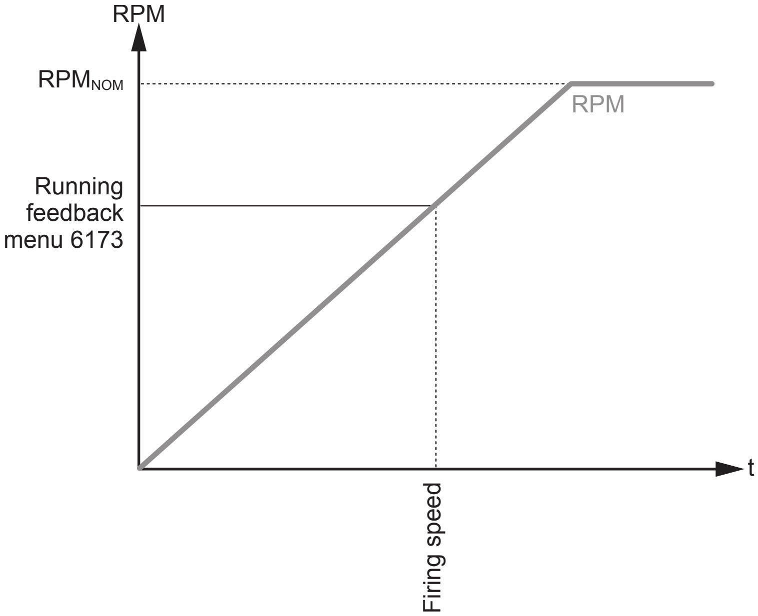
NOTE The running feedback is detected by either the digital input (see diagram above), frequency measurement above 32 Hz, RPM measured by magnetic pick-up or EIC (option H12).

9.1.2 Analogue tacho feedback

When a magnetic pick-up (MPU) is being used, the specific level of revolutions for deactivation of the start relay can be adjusted.

Running feedback

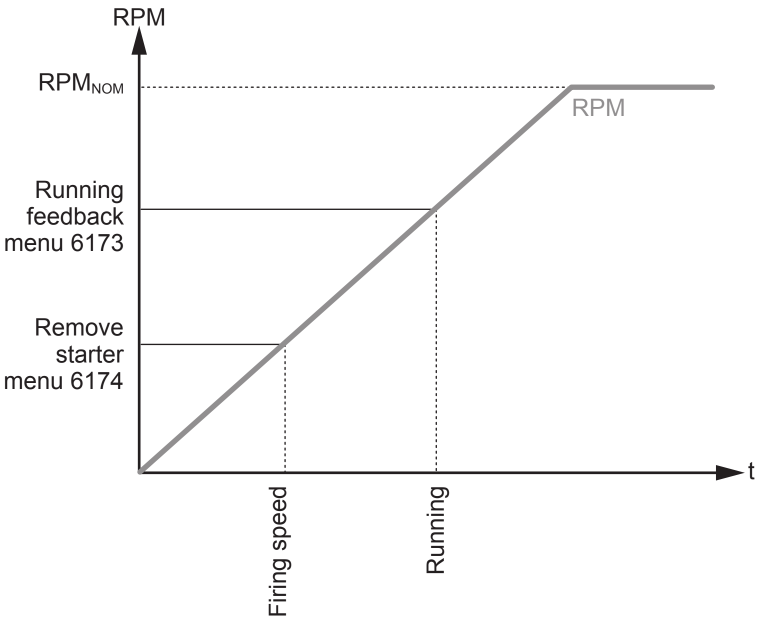
The diagram below shows how the running feedback is detected at the firing speed level. The factory setting is 1000 RPM (6170 Running detect.).



NOTICE
Damage to starter motor Notice that the factory setting of 1000 RPM is higher than the RPM level of starter motors of typical design. Adjust this value to a lower value to avoid damage of the starter motor.

Remove starter input

The drawing below shows how the set point of the remove starter is detected at the firing speed level. The factory setting is 400 RPM (6170 Running detect.).



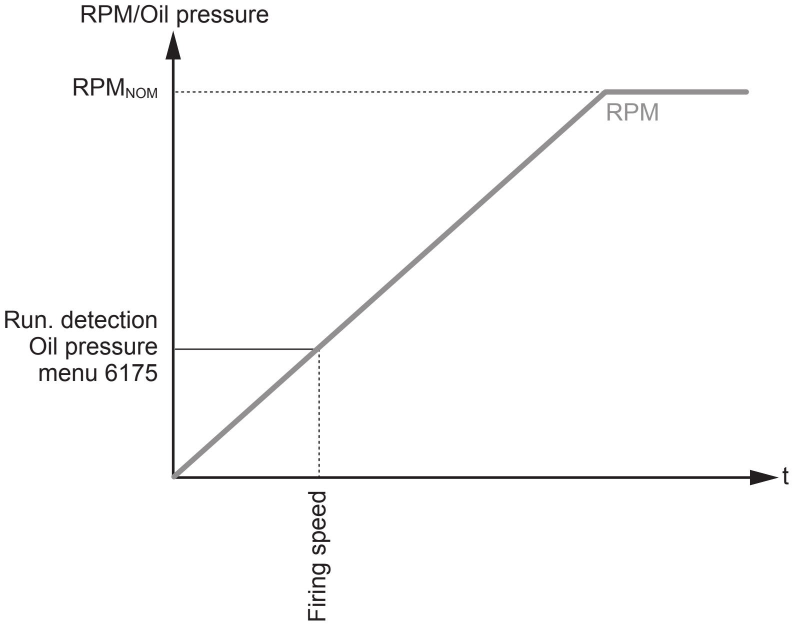
NOTE The number of teeth on the flywheel must be adjusted in menu 6170 when the MPU input is used.

9.1.3 Oil pressure

The multi-inputs on terminals 102, 105 and 108 can be used for the detection of running feedback. The terminal in question must be configured as a RMI input for oil pressure measurement.

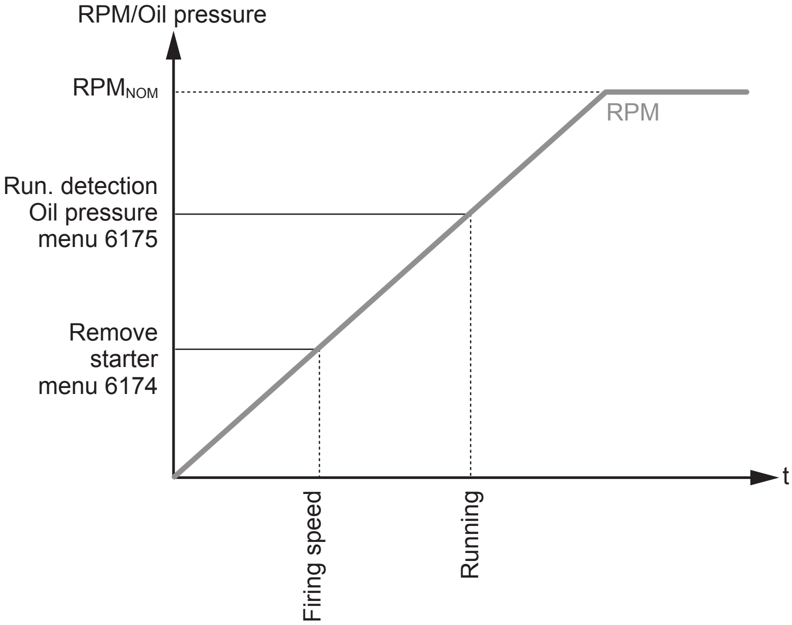
When the oil pressure increases above the adjusted value (6175 Pressure level) then the running feedback is detected and the start sequence is ended.

Running feedback



Remove starter input

The drawing below shows how the set point of the "remove starter input" is detected at the firing speed level. The factory setting is 400 RPM (6170 Running detect.).

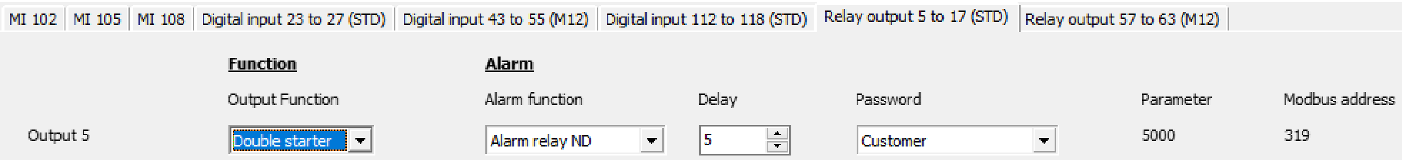


NOTE The remove starter function can use the MPU or a digital input.

9.1.4 Double starter

In some emergency installations, the prime mover is equipped with an extra start motor. Dependent on the configuration, the double starter function can toggle between the two starters or try several attempts with the standard starter before switching to the *double starter*.

The function is set up in parameters 6191-6192, and a relay for cranking with the alternative starter is chosen in the *I/O setup*.



NOTE Remember to write the settings when changing the I/O configuration.

Parameter	Name	Explanation
6191	Standard attempts	Accepted total number of start attempts before a *start failure* alarm is activated
6192	Double attempts	The number of start attempts before redirecting the start signal

The double starter function is enabled by choosing a value higher than zero in channel 6192. This value determines the amount of attempts on each starter before switching to the next. The *standard starter* has first priority. When the maximum allowed number of attempts, defined in channel 6191, is reached, the start attempts stop and the alarm *Start failure* appears.

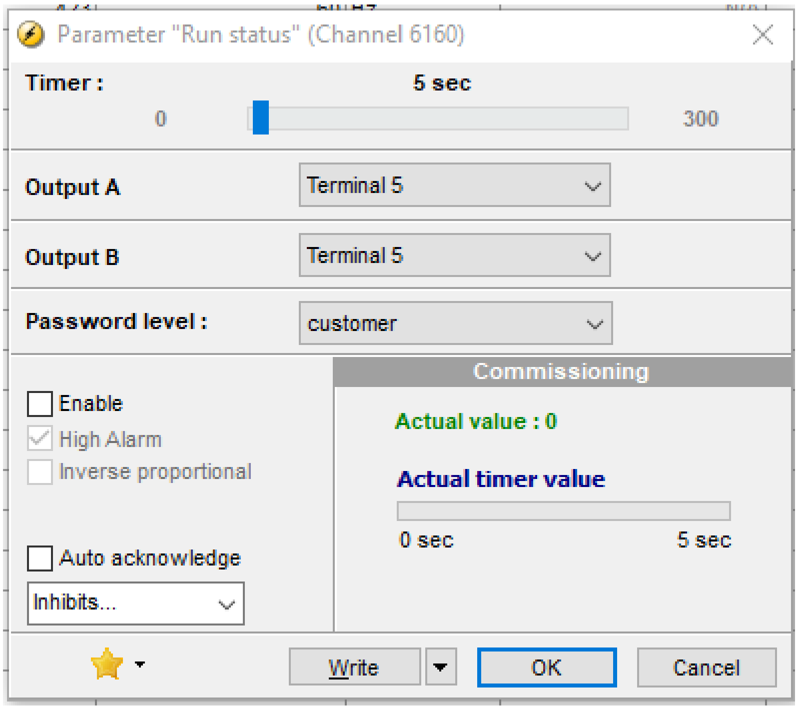
- A value of 1 in channel 6192 results in a toggle function with 1 attempt on each starter between toggling.
- A value of 2 in channel 6192 results in a toggle function with 2 attempts on each starter between toggling.

Examples

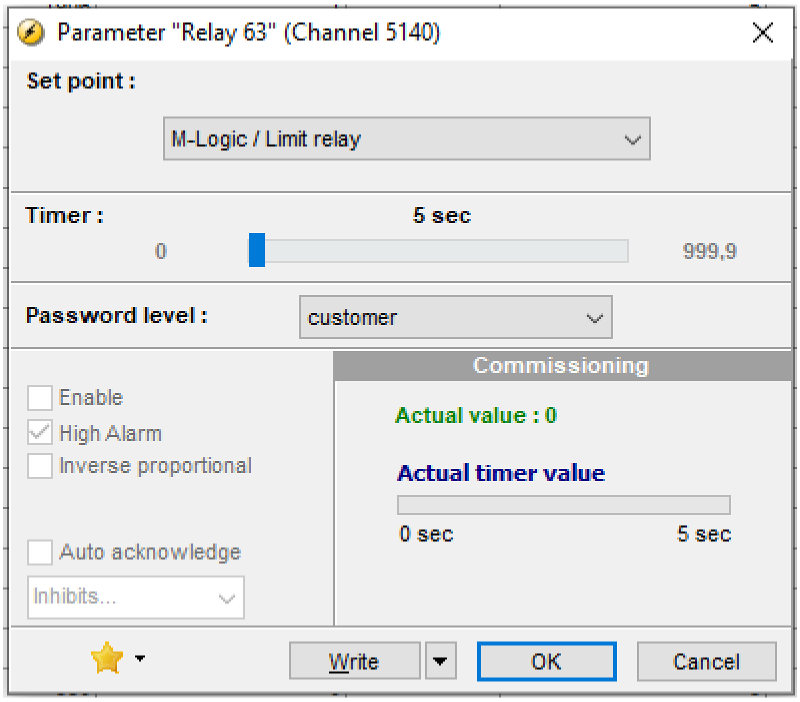
6191 Std attempts	6192 Dbl attempts	1st attempt	2nd attempt	3rd attempt	4th attempt	5th attempt
3	1	Standard	Double	Standard	Alarm	-
5	1	Standard	Double	Standard	Double	Standard
5	2	Standard	Standard	Double	Double	Standard
4	5	Standard	Standard	Standard	Standard	Alarm

9.2 Running output

Menu 6160 Run status can be configured to give a digital output when the genset is running.



Select the correct relay number in output A and output B and enable the function. Change the relay function to limit in the I/O menu. Then the relay will activate, but no alarm will appear. Note that to avoid an alarm, both output A and output B need to be configured to a relay.



NOTE If the relay function is not changed to *M-Logic / Limit* function, an alarm will appear at every running situation.

9.3 Idle running

The purpose of the idle run function is to change the start and stop sequences to allow the genset to operate under low temperature conditions.

It is possible to use the idle run function with or without timers. Two timers are available. One timer is used in the start sequence, and one timer is used in the stop sequence.

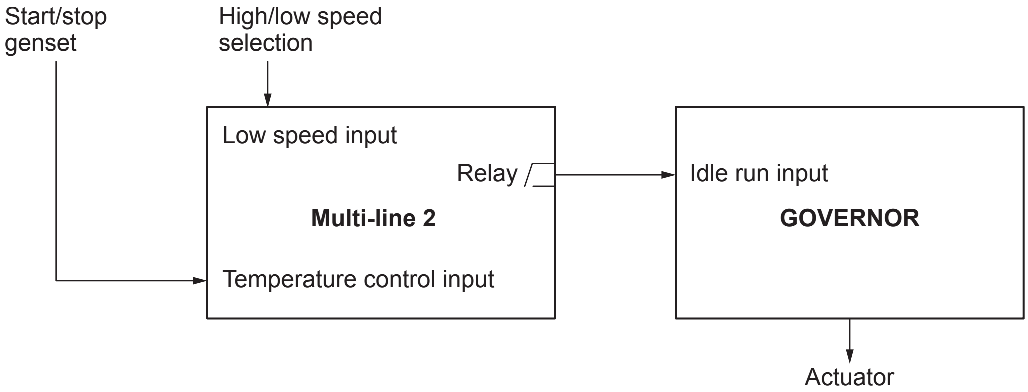
The main purpose of the function is to prevent the genset from stopping. The timers are available to make the function flexible.

NOTE The speed governor must be prepared for the idle run function if this function is to be used.

The function is typically used in installations where the genset is exposed to low temperatures which could generate starting problems or damage the genset.

9.3.1 Description

The function is enabled and configured in menu 6290 *Idle running*. The governor must regulate the engine to run at the idle speed based on a digital signal from the controller (see the principle diagram below).



NOTE To invert the relay output, you need to use a changeover relay. Connect the wiring to the common and normally closed terminals.

When the function is enabled, two digital inputs are used for control purposes:

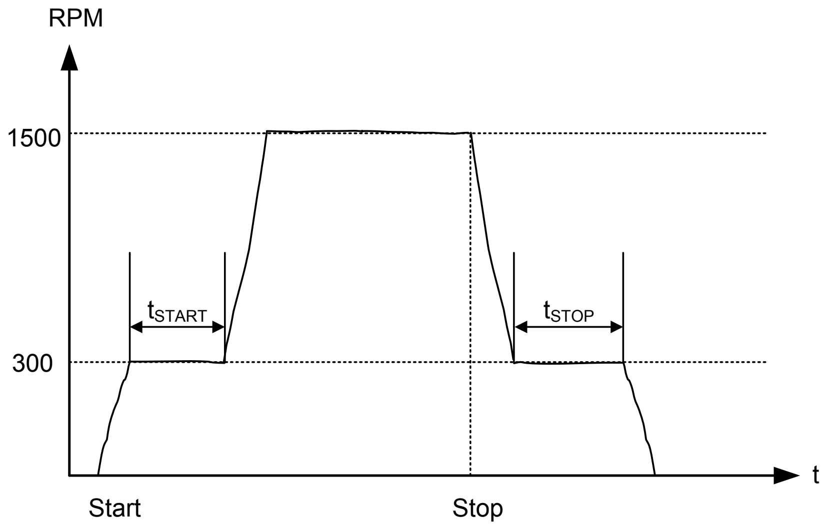
No.	Input	Description
1	Low speed input	This input is used to change between idle speed and nominal speed. This input does not prevent the genset from stopping - it is only a selection between idle and nominal speed. If the idle run function is selected using a timer, the low speed input is overruled.
2	Temperature control input	When this input is activated, the genset will start. It will not be able to stop as long as this input is activated.

NOTE Turbo chargers not originally prepared for operating in the low speed area can be damaged if the genset is running in "idle run" for too long.

9.3.2 Examples

Idle speed during starting and stopping

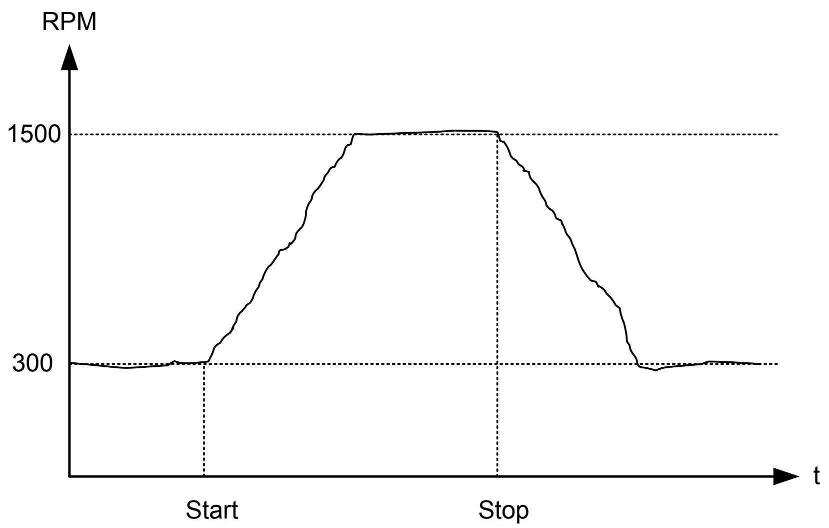
In this example both the start and the stop timers are activated. The start and stop sequences are changed in order to let the genset stay at the idle level before speeding up. It also decreases the speed to the idle level for a specified delay time before stopping.



Idle speed with a digital input configured to low speed

In this example, both timers must be deactivated. The idle speed with low speed activated will run in idle speed until the low speed input is deactivated, and subsequently the genset will regulate to nominal values.

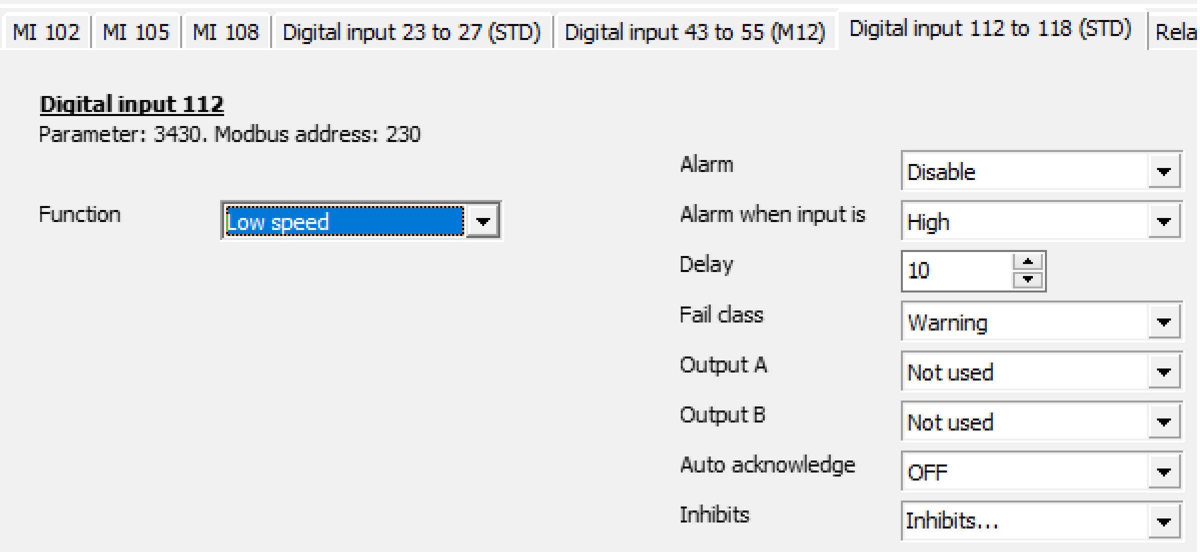
If the genset is to be prevented from stopping, then the digital input "temp control" must be left ON at all times. In that case the characteristic looks like this:



NOTE The oil pressure alarm (RMI oil) will be enabled during idle run if set to "ON".

9.3.3 Configuration of digital input

The digital input is configured under *I/O setup* in the USW.

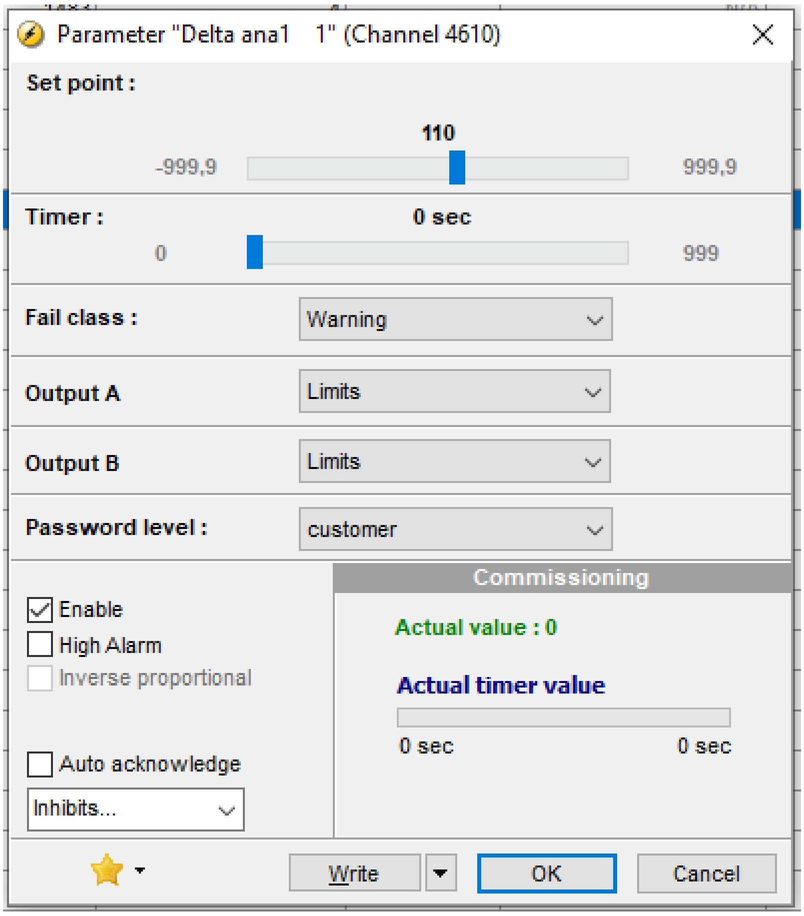


9.3.4 Temperature-dependent idle start-up

This is an example of how to set up a system that will start up in idle speed, if the coolant temperature is below a specified value. When the temperature exceeds the specified value, the genset will ramp up to nominal values.

Example

The function is made with delta analogue 1 (menus 4601, 4602 and 4610) and one M-Logic line. After starting, when the coolant temperature is below 110 degrees, the controller will idle the genset. Once the temperature reaches 110 degrees, the controller will automatically ramp up to full speed. See the settings below.



In order for this function to work, menu 6295 Idle active must be enabled, and the relay output must be configured. Otherwise the low speed function will not work.

9.3.5 Inhibit

The alarms that are deactivated by the inhibit function are inhibited in the usual manner, except for the oil pressure alarms; RMI oil 102, 105 and 108 which are active during "idle run" as well.

9.3.6 Running signal

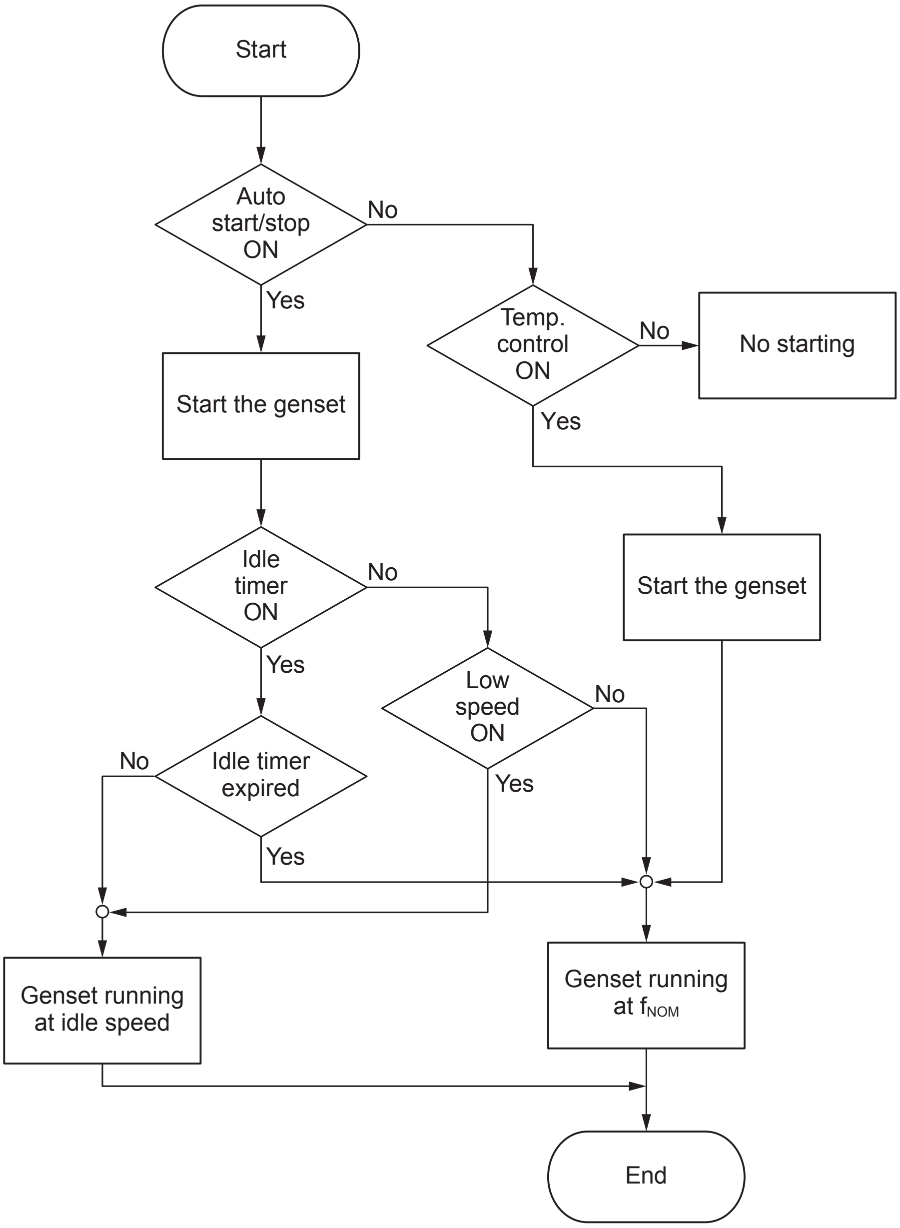
The running feedback must be activated when the genset is running in idle mode.

NOTE The running detection level (parameter 6173) must be below the idle speed. See Start-up overview with idle run.

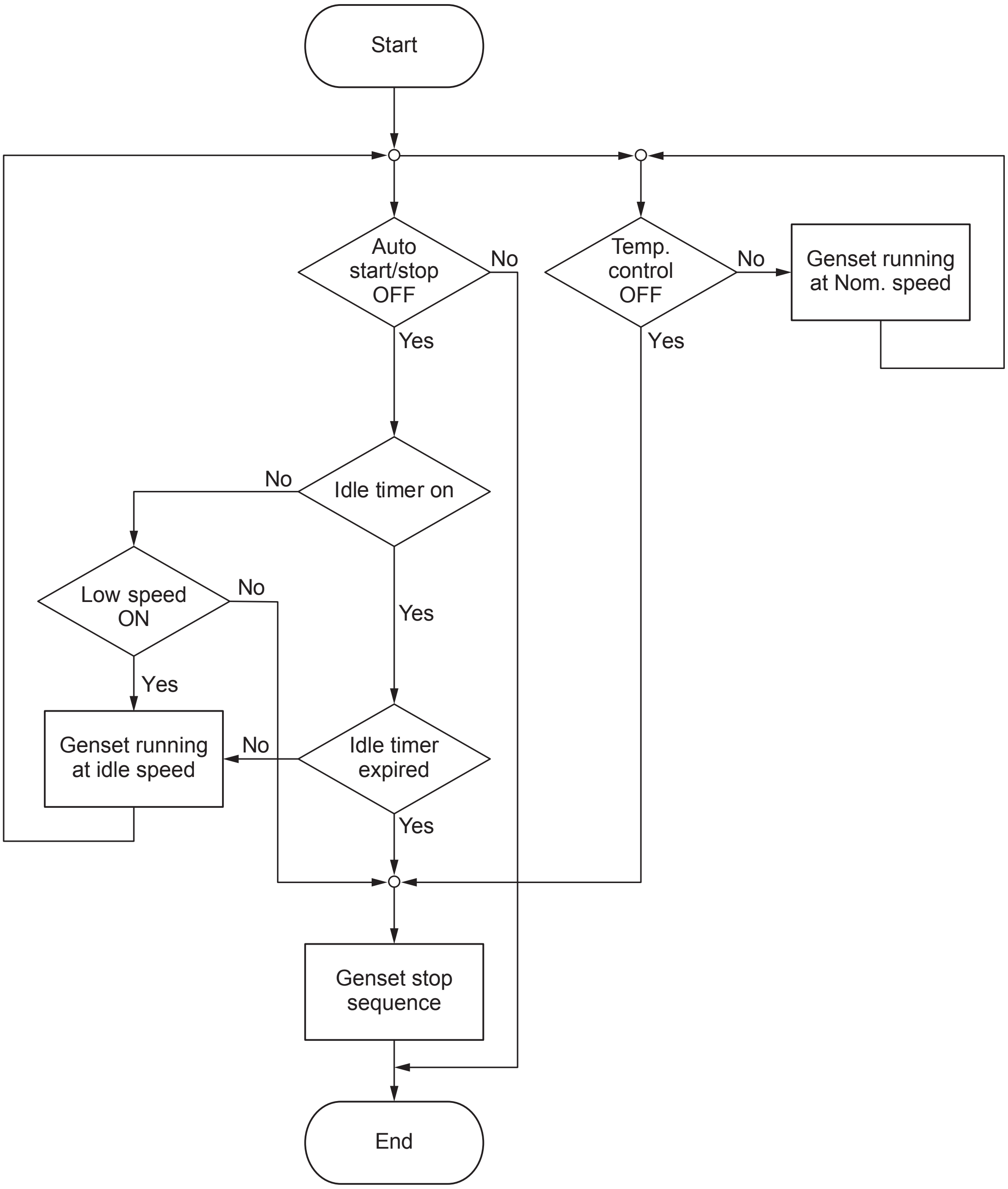
9.3.7 Idle speed flowcharts

The flowcharts illustrate the starting and stopping of the genset by use of the inputs "temp control" and "low speed".

Start


Start
Auto start/stop ON
No
Yes
Temp. control ON
No
No starting
Yes
Start the genset
Start the genset
Idle timer ON
No
Yes
Low speed ON
No
Yes
Idle timer expired
No
Yes
Genset running at idle speed
Genset running at f_{NOM}
End

Stop



9.4 Analogue load sharing

If hardware option M12 is installed, the controller can use analogue load sharing lines to share the load equally (as a percentage of the nominal power). Analogue load sharing can be used for both the active and/or the reactive load.

ANSI number

Function	ANSI no.
Analogue load sharing between gensets	90

When is analogue load sharing active?

Analogue load sharing is active automatically when:

- The mains breaker is open and the genset breaker is closed. That is, the connected genset is not parallel to the mains (island operation).
  - You can use M-Logic to disable analogue load sharing.

Analogue load sharing is automatically not active when:

- The genset breaker is open.

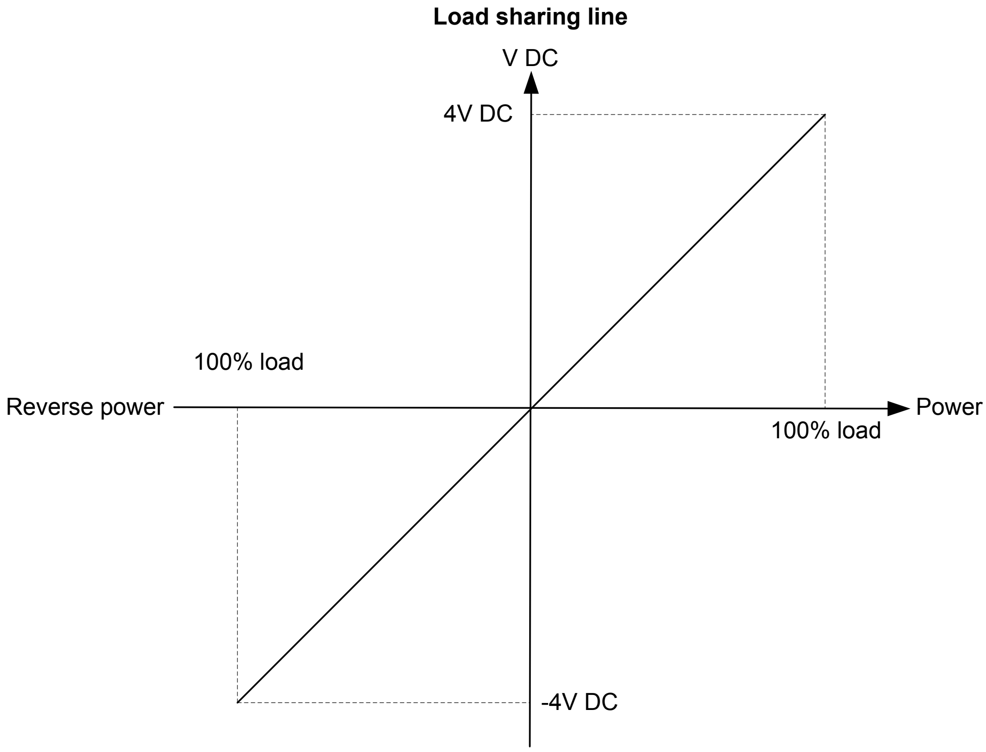
Analogue load sharing is automatically ignored when the power management system gives the genset controller a power set point:

- You can use M-Logic to force the controller to use analogue load sharing. This allows analogue load sharing with externally controlled gensets. See Load sharing type for more information.
- You can also use M-Logic to activate analogue load sharing if the power management CAN bus communication fails.

More information
See **Genset functions, Load sharing** in **Option G5 Power management** for more information.

How does it work

A voltage signal proportional to the load produced by the genset is supplied on the load sharing line. When the generator load is 0 %, 0 V DC is supplied. When the load is 100 %, the voltage is 4 V DC, as shown below. Active load sharing is shown. Reactive load sharing is similar.



9.4.1 Analogue load sharing terminals

Terminal	Function	Technical data	Description
37	-5/+5 V DC	Analogue I/O	Active load sharing line
38	Com.	Common	Common
39	-5/+5 V DC	Analogue I/O	Reactive load sharing line

9.4.2 Working principle

The controller supplies a voltage on the load sharing line proportional to the genset's actual load. This voltage comes from an internal power transducer. At the same time, the actual voltage on the load sharing line is measured.

If the measured voltage is higher than the voltage from the internal power transducer, the controller increases its load to match the voltage on the load sharing line.

If the measured voltage is lower than the voltage from the internal power transducer, the controller decreases its load to match the voltage on the load sharing line.

The voltage on the load sharing line only differs from the voltage from the internal power transducer, if two or more controllers are connected to the load share line.

When the hardware is installed, the analogue load share line is active. That it, it is active both when one generator is running in a single application, and when a number of generators are actually sharing the load. For generator running alone, disabling the load share line is recommended to keep the frequency regulator active.

NOTE To disable the load sharing line, use M-Logic *Output, Inhibits, Inh. analogue load share*.

To improve the handling of several generators in the same application, analogue load sharing works as backup system for power management option G5. This means that if both analogue load sharing and power management are available in the same controller, load sharing is done by the CAN bus communication as the primary choice. If a CAN bus error occurs, load sharing continues on the analogue load sharing line. The generators stay stable even though the power management is lost.

Example 1: Load adjustment

Two generators are running in parallel. The loads of the generators are:

Generator	Actual load	Voltage on load sharing line
Generator 1	100 %	4 V DC
Generator 2	0 %	0 V DC

The voltage level on the load sharing line can be calculated to:

U_{LS}: (4 + 0) / 2 = 2.0 V DC

Now generator 1 decreases the load to match the voltage on the load sharing line (in this example, 2.0 V DC). Generator 2 increases the load to match the 2.0 V DC.

The new load share situation is:

Generator	Actual load	Voltage on load sharing line
Generator 1	50 %	2.0 V DC
Generator 2	50 %	2.0 V DC

Example 2: Different generator size

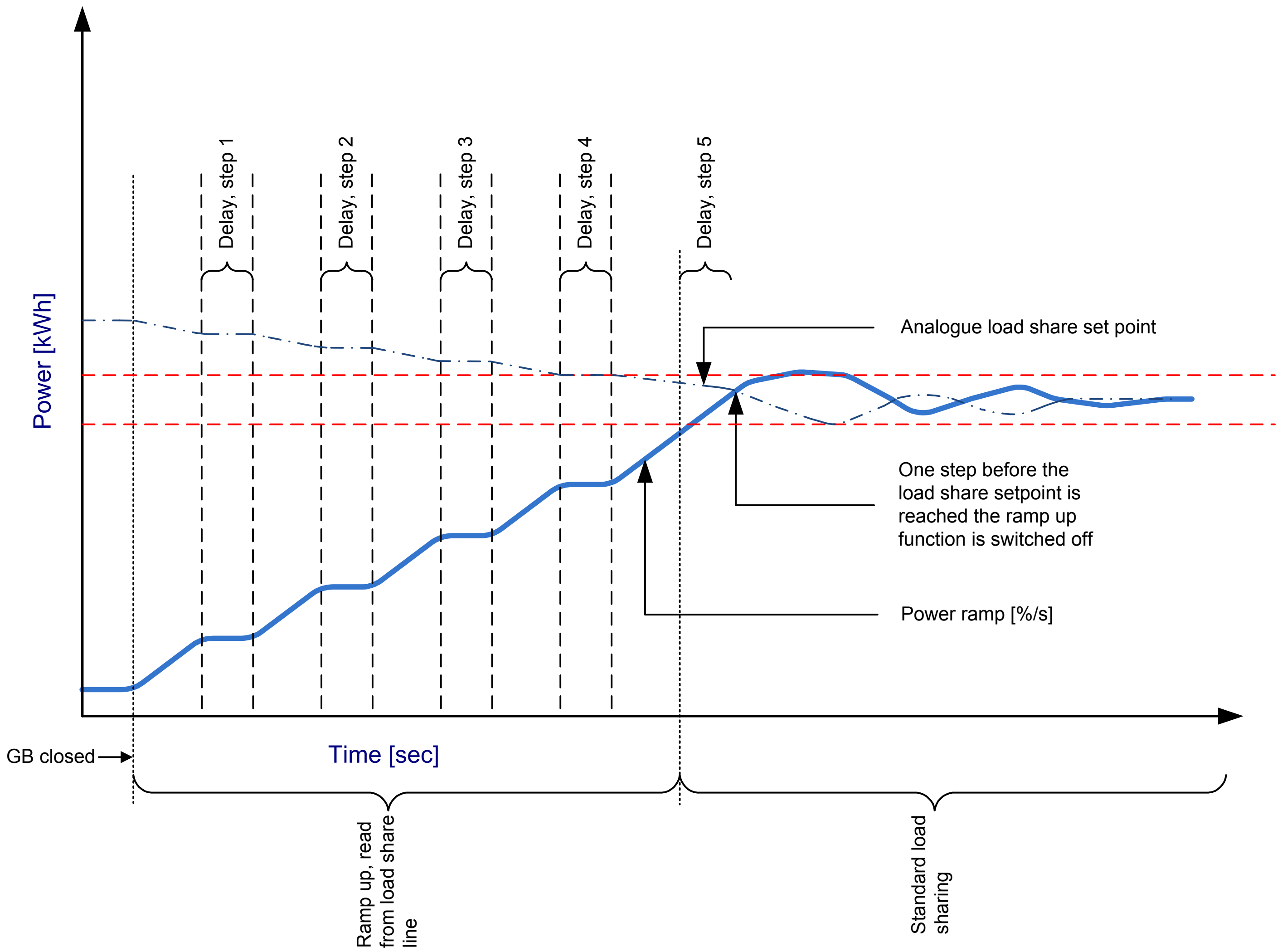
If the generator size differs, the load sharing is still done based on a percentage of the nominal power.

Two generators supply the busbar. The total load is 550 kW.

Generator	Nominal power	Actual load	Voltage on load sharing line
Generator 1	1000 kW	500 kW	2.0 V DC
Generator 2	100 kW	50 kW	2.0 V DC

Both generators are supplying 50 % of their nominal power.

9.4.3 Island ramp up with load steps



The genset controller includes a load ramp up function. If enabled, this also controls the load ramp up for analogue load sharing.

When menu 2614 is enabled, the power set point continues to rise in ramp up steps, determined by menu 2615, towards the load sharing set point. The delay time between each ramp up step will be determined by menu 2613. The ramp up continues until the load sharing set point is reached. The regulator is then switched to standard load sharing mode.

If the delay point is set to 20 % and the number of load steps is set to 3, the genset ramps to 20 %, waits the configured delay time, ramps to 40 %, waits, ramps to 60 %, waits and then ramps to the system set point. If the set point is 50 %, the ramp stops at 50 %.

9.4.4 Freeze power ramp

You can use a command in M-Logic (*Output*, *Command*, *Freeze ramp*) to freeze the ramp.

Freeze ramp active:

- The power ramp can be stopped at any point. The set point is maintained as long as the freeze is active.
- If the freeze is activated while ramping from one delay point to another, the ramp is fixed until the freeze is deactivated.
- If the freeze is activated while the delay timer is timing out, the timer is stopped and does not continue until the freeze is deactivated.

9.4.5 Load sharing type

The controller can be configured to work with different load sharing modules and different ranges for the load sharing signal. This is controlled by the parameters in 6380 (signal level) and 6390 (load sharing type). The signal level is used to adjust the maximum output of the load sharing lines. The default range is 0 to 4 V DC, and therefore 4 V DC is the voltage applied to the load sharing line at 100 % load. If the AGC is connected to another product where the load sharing range is different, then the range can be changed in 6380.

To be able to adjust the maximum range, set 6391 to *Adjustable*. The AGC can provide between 1.0 and 5.0 V DC at 100 % load. Load sharing interfacing to DEIF Uni-line LSU (load sharing unit) and Multi-line 2 version 1 and version 2 can require a 0 to 5 V DC range. If the load sharing is unequal, check the configuration.

Parameter 6391 can be:

- Adjustable
- Selco T4800
- Cummins PCC
- Woodward SPM-D11

The parameters in 6380 are only used if *Adjustable* is selected in 6391. For other selections, the AGC modifies the signal level of the load sharing lines to match the selected controller/load share unit.

9.4.6 Load sharing modules

For interfacing to unspecified load sharing modules, it may be necessary to provide galvanic separation for the load sharing lines. For proper function, the input impedance of such isolation amplifiers should be high impedance.

9.4.7 Selco T4800 load sharer

T4800 is for kW sharing only (that is, not kVAr sharing).

The signal level is +/-1 V DC, so the AGC automatically adapts to this level. The terminals of T4800 are 12 (com) and 13 (+).

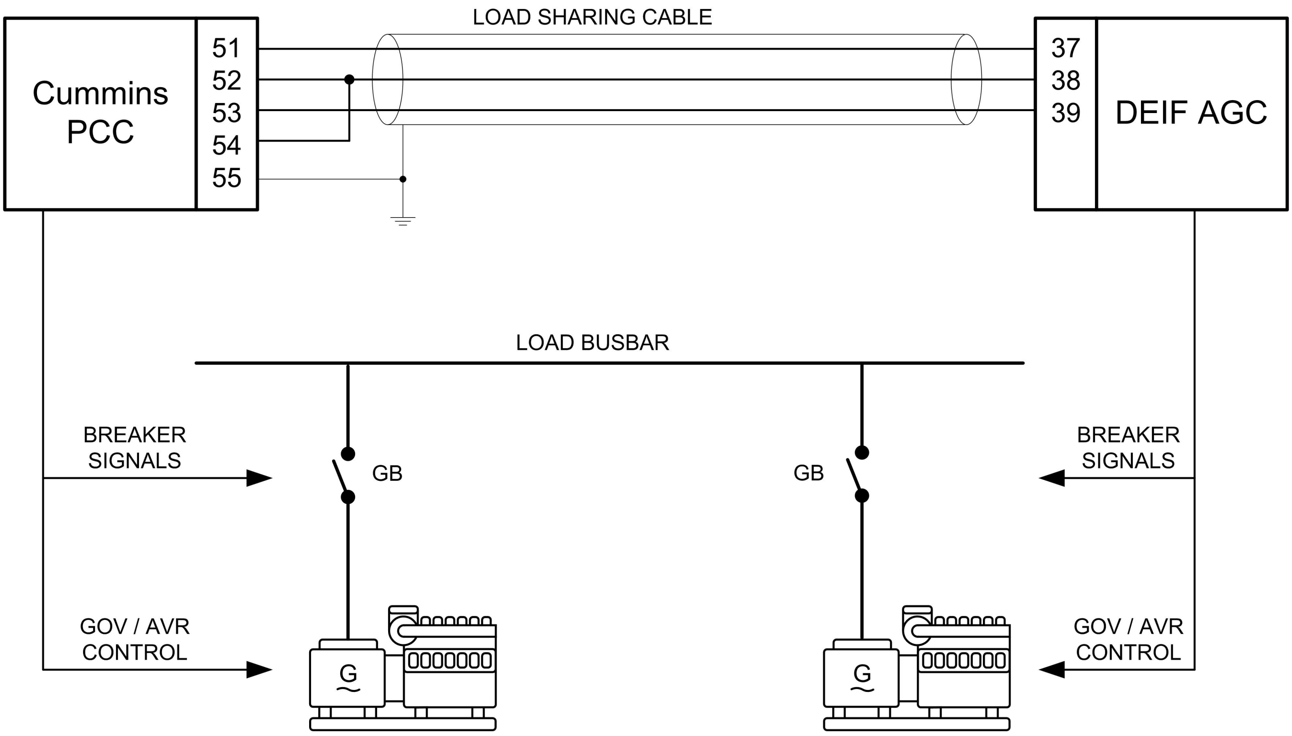
For T4800, the frequency difference of the measured compared to generator nominal is taken into account to prevent unequal load sharing. This is not user-configurable.

9.4.8 Cummins PCC

The signal level is 0.3 to 2.1 V DC, so the AGC adapts automatically to this level. The terminals (TB3) of the Cummins PCC (for example PCC3100 and PCC3201) are on connector 8, and the terminals are 51 (kW), 53 (kVAr), 52 and 54 (common). Terminal 55 is a dedicated terminal for the shield of the load sharing cable.

Cummins PCC applications

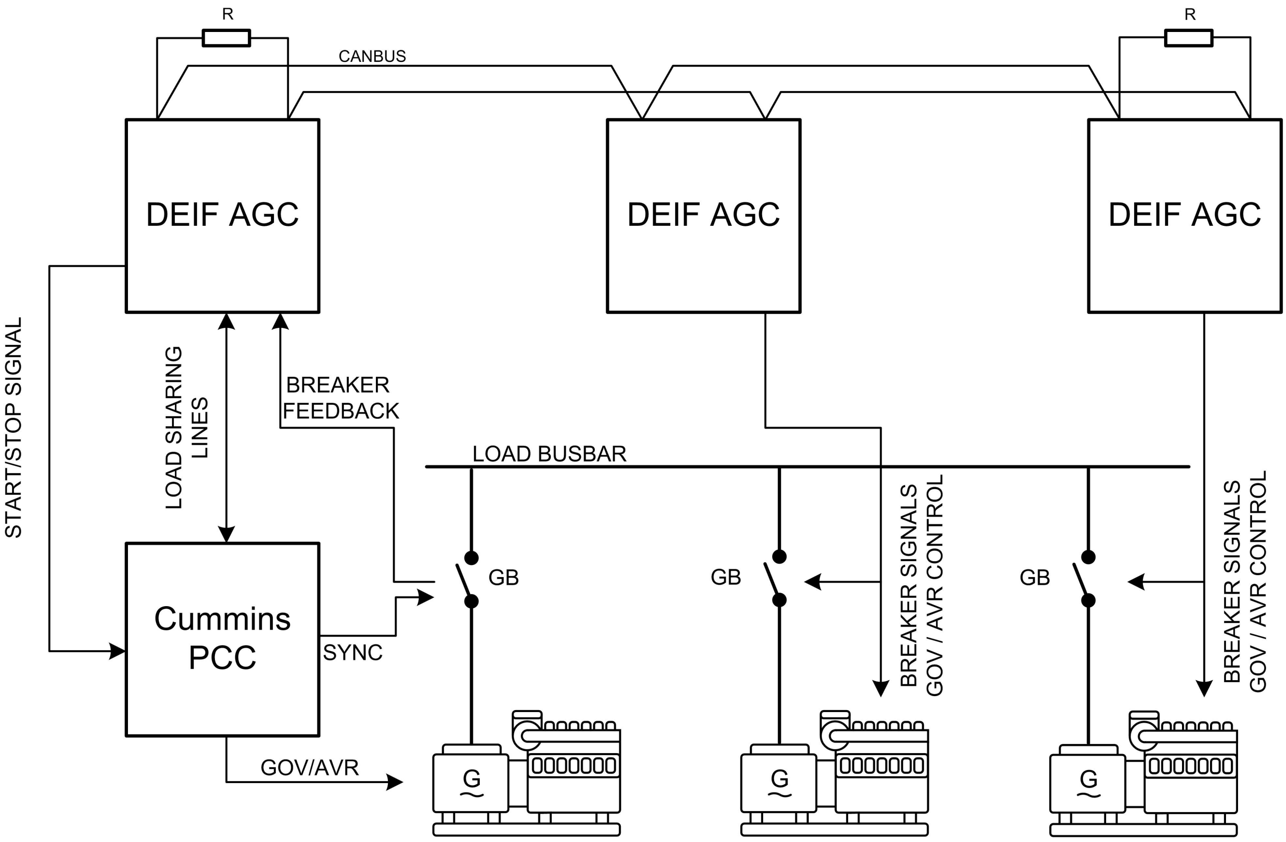
Figure 9.1 PCC interface to AGC



PCC in the DEIF power management system

If the AGC is part of a power management system, it normally gets load sharing information from the power management system over CAN bus. You can force an AGC to use the analogue load sharing lines: Activate *Output*, *Command Power management*, *Use Ana LS instead of CAN* in M-Logic. This allows the Cummins PCC to share the load with the AGCs.

This is useful if the AGC is placed on all gensets, only sending start and stop commands to the PCC. This means that the Cummins ILSI unit is not necessary.



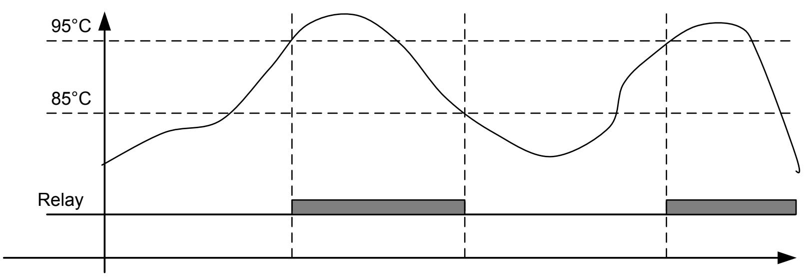
9.5 Ventilation

This function can be used to control the cooling of the engine. The purpose is to use a multi-input for measuring the cooling water temperature and that way activate an external ventilation system to keep the engine below a maximum temperature. The functionality is shown in the below diagram.

Set points available (6460 Max ventilation):

- **Set point**: The limit for activation of the relay set in Output A.
- **Output A**: The relay activated when the set point is exceeded.
- **Hysteresis**: The number of degrees the temperature has to be below the set point in order to deactivate the relay set in Output A.
- **Enable**: Enable/disable the ventilation function

NOTE The type of input to use for the temperature measurement is selected in parameter 6323 *Engine heater*.



9.5.1 Max. ventilation alarm

Two alarms can be set up in menu 6470 and menu 6480 to activate if the temperature keeps rising after the start set point has been reached.

9.6 Fan logic

The AGC is able to control four different fans. This could for example be air supply fans for supplying air to a genset in a closed enclosure, or radiator fans for switching on and off cooling fans for air coolers.

There are two features in the fan control of the AGC:

1. Priority rearranging depending on running hours of the fans
2. Temperature-dependent start and stop

A priority routine ensures that the running hours of the available fans are evened out and the priority shifts between them.

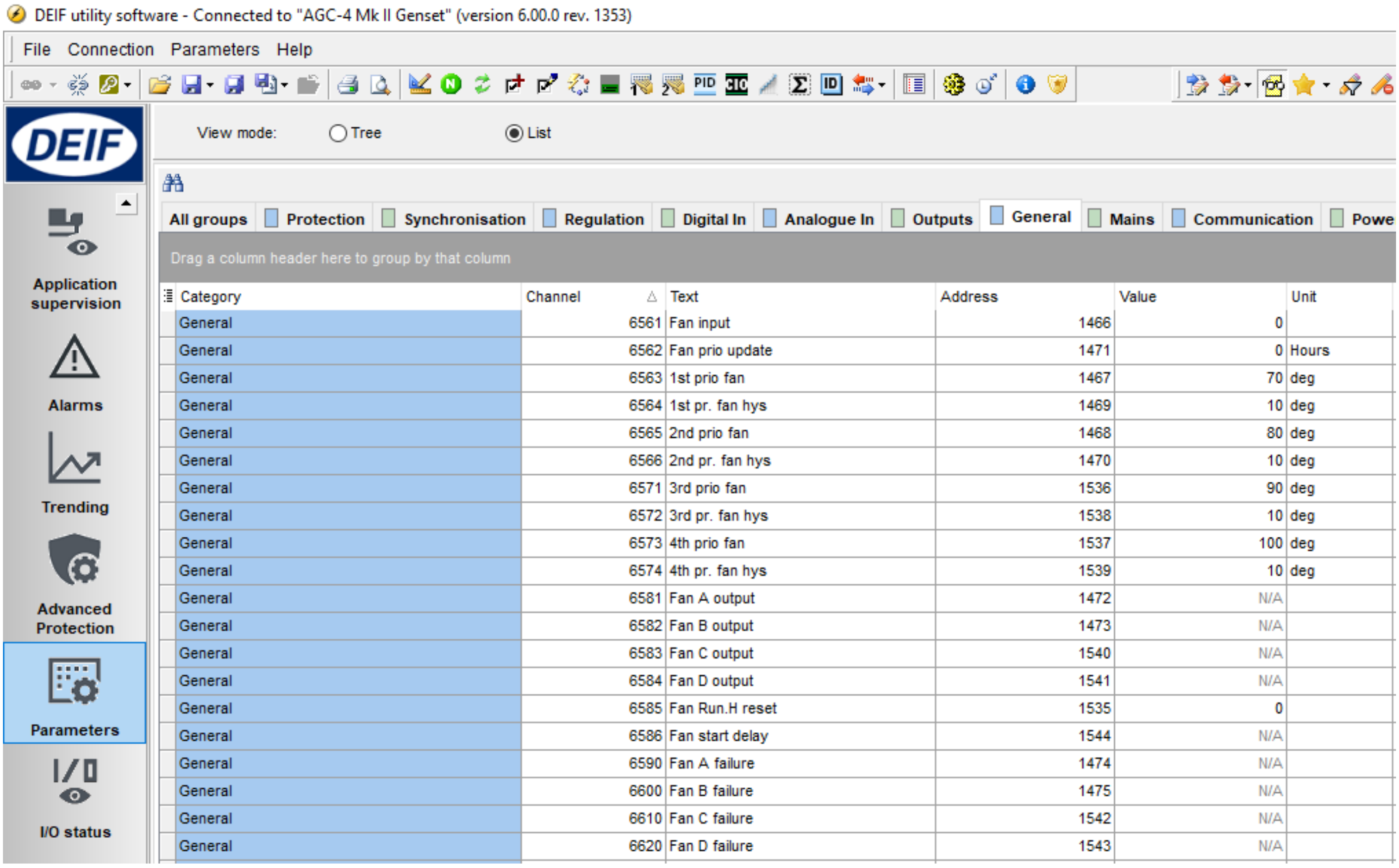
The functionality behind the temperature-dependent start/stop is that the AGC measures a temperature, for example cooling water temperature, and based on this temperature it switches on and off relays that must be used for engaging the fan(s) itself.

NOTE The fan control function is active as long as running feedback is detected.

9.6.1 Fan parameters

Each fan has a group of parameters that defines their scheme of operation. It is recommended to use the PC utility SW for the setup, because then it is possible to see all parameters. The setup of the fan control is done in the menus 6561-6620 and by using M-Logic in the PC utility SW.

Parameters



Category	Channel	Text	Address	Value	Unit
General	6561	Fan input	1466	0	
General	6562	Fan prio update	1471	0	Hours
General	6563	1st prio fan	1467	70	deg
General	6564	1st pr. fan hys	1469	10	deg
General	6565	2nd prio fan	1468	80	deg
General	6566	2nd pr. fan hys	1470	10	deg
General	6571	3rd prio fan	1536	90	deg
General	6572	3rd pr. fan hys	1538	10	deg
General	6573	4th prio fan	1537	100	deg
General	6574	4th pr. fan hys	1539	10	deg
General	6581	Fan A output	1472	N/A	
General	6582	Fan B output	1473	N/A	
General	6583	Fan C output	1540	N/A	
General	6584	Fan D output	1541	N/A	
General	6585	Fan Run.H reset	1535	0	
General	6586	Fan start delay	1544	N/A	
General	6590	Fan A failure	1474	N/A	
General	6600	Fan B failure	1475	N/A	
General	6610	Fan C failure	1542	N/A	
General	6620	Fan D failure	1543	N/A	

9.6.2 Input for fan control

The fan control requires a temperature input in order to start and stop the fans based on a temperature measurement.

Fan temperature input is set up in parameter 6561, and this input can be selected between these inputs:

- Three multi-inputs in slot #7 are available
- EIC measurement (engine interface communication)
- External analogue input 1-8 (H12.X)
- Analogue inputs (M15.X)
- Multi-inputs (M16.X)

The multi-inputs can be configured to, for example, a Pt100 sensor that measures an engine- or ambient temperature. If EIC is selected, this is defined as the highest measured temperature of either cooling water or oil temperatures.

Based on the measurement of the selected input, the fan(s) are started and stopped.

9.6.3 Fan start/stop

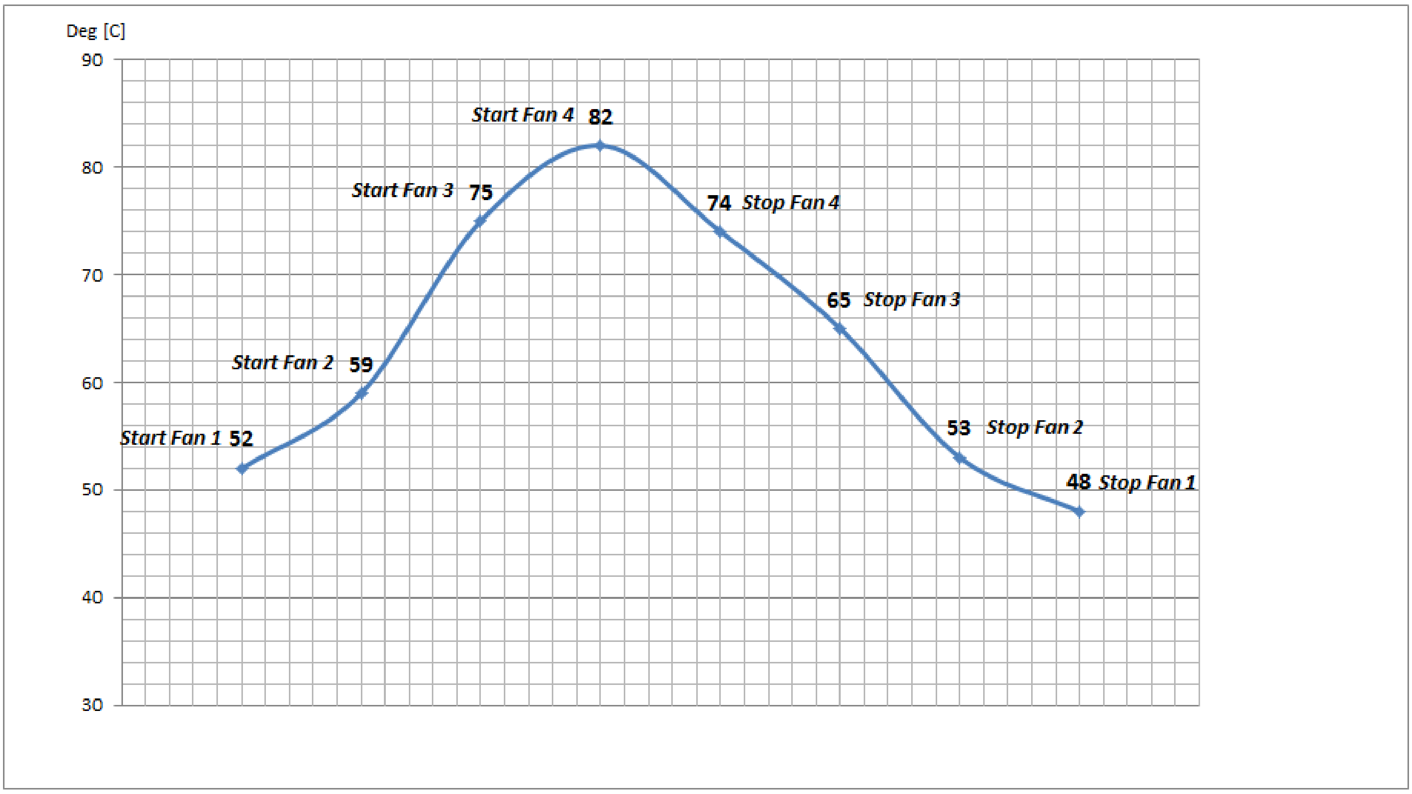
The start and stop settings of the fan(s) are set up in parameters 6563 to 6574. With the settings in the table below, the illustrative curve can be observed.

A hysteresis (abbreviation: hyst.) ensures that there is a range between the start and stop.

6563	1st level fan setp.	50	deg
6564	1st level fan hyst.	2	deg
6565	2nd level fan setp.	56	deg
6566	2nd level fan hyst.	3	deg
6571	3rd level fan setp.	70	deg
6572	3rd level fan hyst.	5	deg
6573	4th level fan setp.	78	deg
6574	4th level fan hyst.	4	deg

Fan	Setp.	hys.	Start	Stop
1	50	2	52	
2	56	3	59	
3	70	5	75	
4	78	4	82	
4	78	4		74
3	70	5		65
2	56	3		53
1	50	2		48

The following start/stop curve will be generated if a bow setting is used:



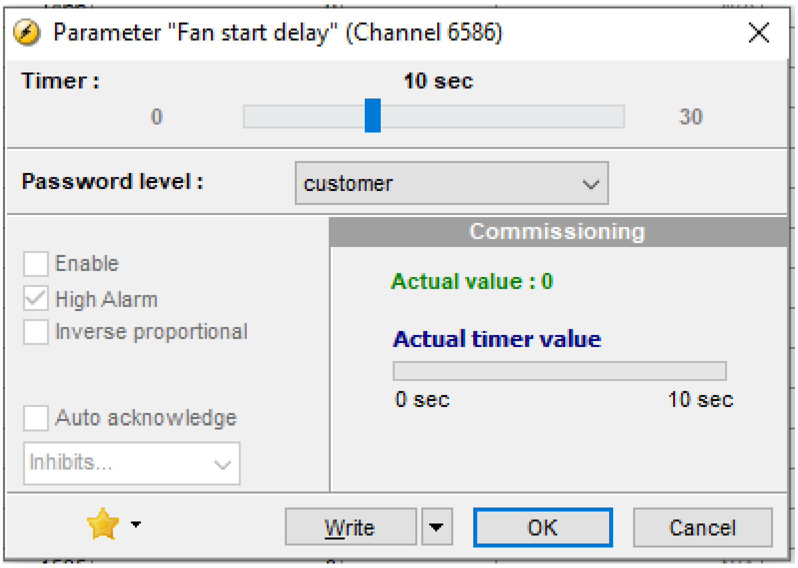
9.6.4 Fan output

At parameter 6581 to 6584, the output relays for fans A to D are selected. The purpose of these relays is to issue a signal to the fan starter cabinet. The relay must be energised for the fan to run.

Gen	6581	Fan A output	1472	N/A		N/A	Terminal 57
Gen	6582	Fan B output	1473	N/A		N/A	Terminal 59
Gen	6583	Fan C output	1540	N/A		N/A	Terminal 61
Gen	6584	Fan D output	1541	N/A		N/A	Terminal 63

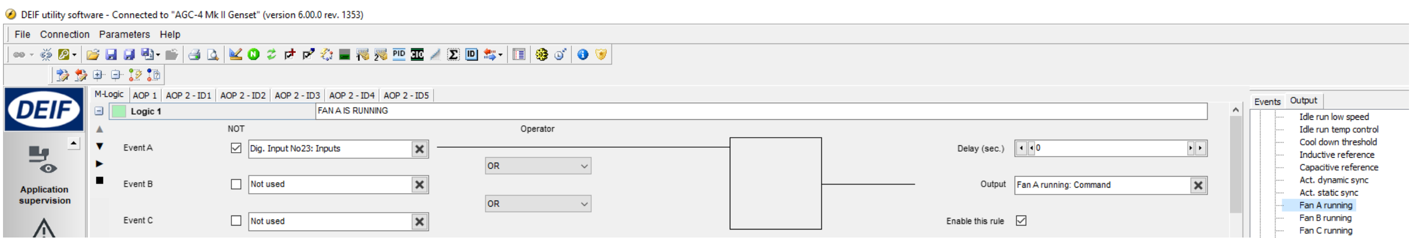
9.6.5 Fan start delay

If two or more fans are requested to be started at the same time, it is possible to add a start delay between each fan start. The reason for this is to limit the peak start current, so all fans will not contribute with a start current at the same time. This delay is adjusted in the menu 6586.



9.6.6 Fan running feedback

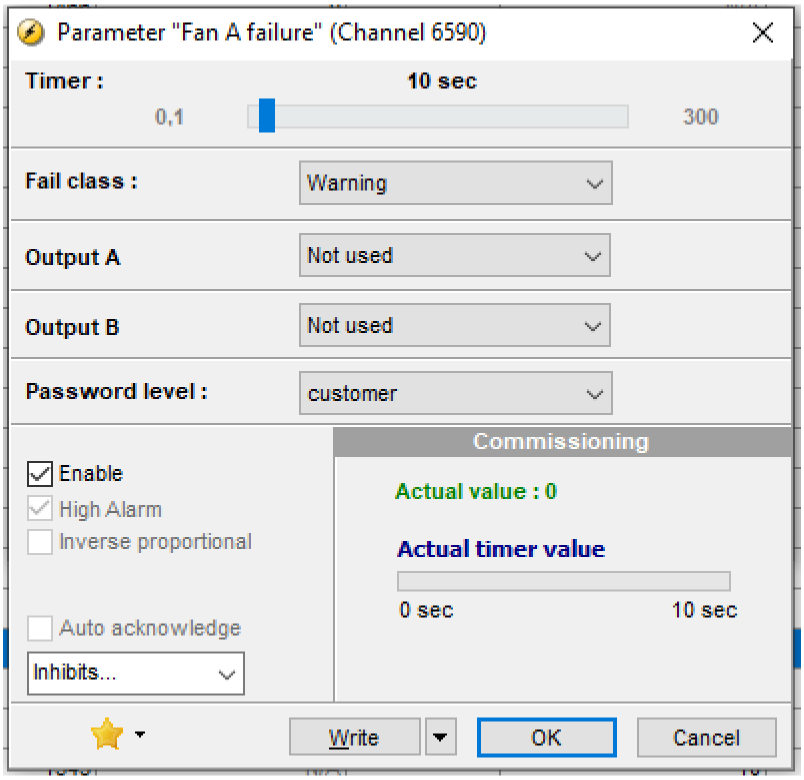
To make sure that the fan is running, it is possible to assign a digital input as a running feedback. The running feedback has to be programmed through M-Logic. Here is an example.



The *Fan A/B/C/D running command* output tells the AGC that the fan is running. The output is found under *Output, Command* as shown above.

9.6.7 Fan failure

It is possible to activate an alarm if the fan does not start. The fan failure alarm appears if the running feedback from the fan does not appear. In parameters 6590 to 6620, the fan failure alarms are set up for fans A to D.

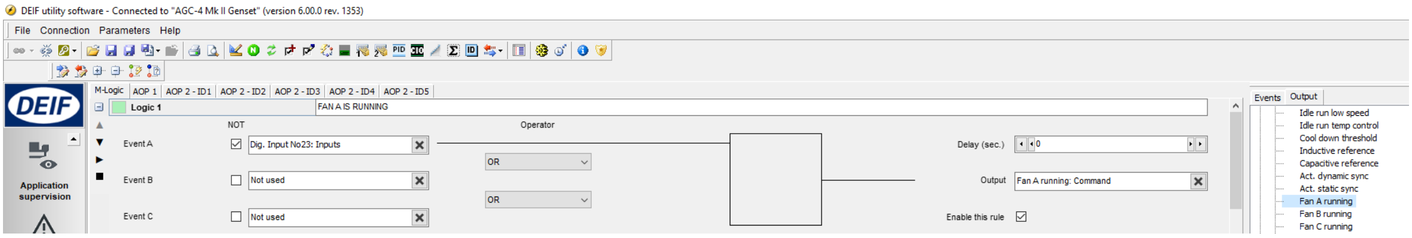


9.6.8 Fan priority (running hours)

The priority of the fans A to D rotates automatically from 1st to 4th priority. This is done automatically, because the running hours of the fans are detected and are used for the rearranging.

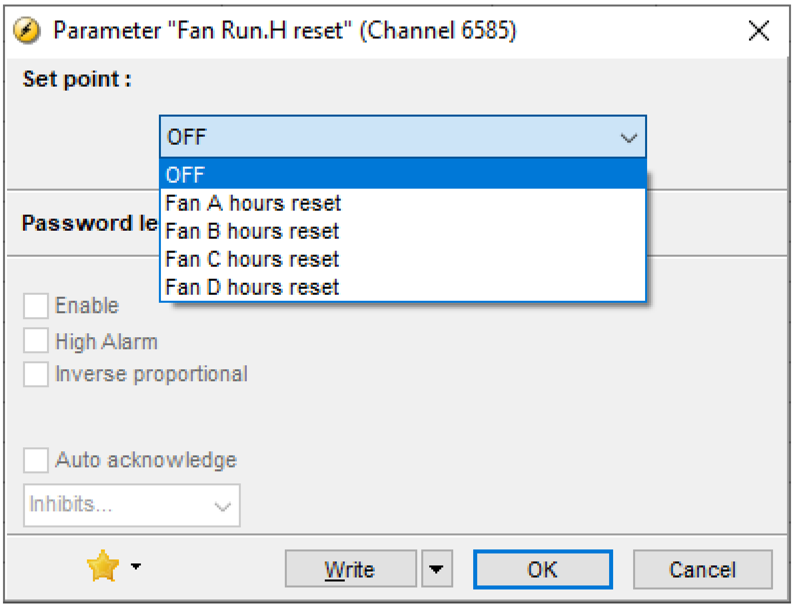
M-Logic setup

If the fan unit is raising a signal that is led to a digital input on the AGC when it is running, the following M-Logic must be programmed:



When it is not possible to get a running feedback from the fan unit, the internal relay of the AGC must be used to indicate that the fan is running. If, for example, Relay 57 is the relay for Fan A, the following M-Logic must be programmed:

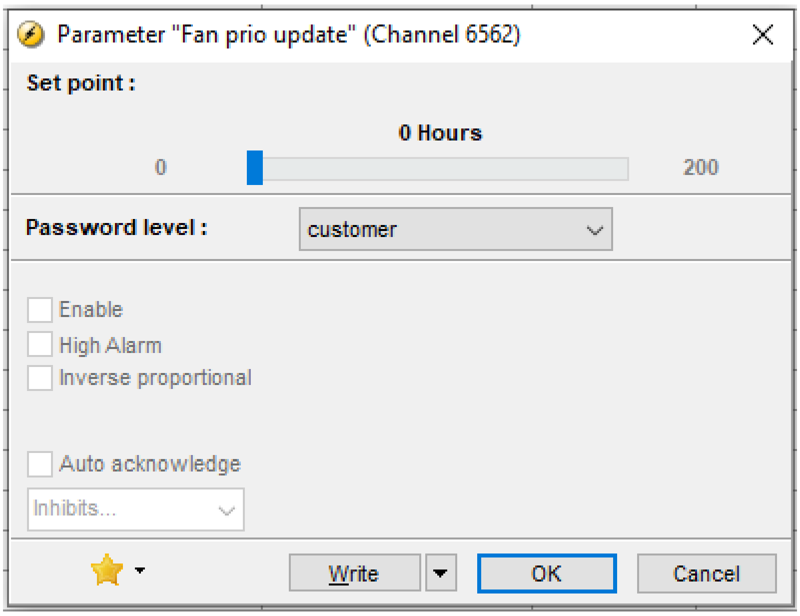
The running hours can be reset by selecting the fan to reset in parameter 6585.



NOTE Only reset is possible. It is not possible to add an offset to the run hour counter.

9.6.9 Fan priority update

In parameter 6562, the priority update rate (the hours between priority changes) is selected:



If the fan priority update is set to 0 hours, the priority order is: Fan A, Fan B, Fan C, Fan D.

9.7 Derate genset

The derate function reduces the maximum output power of the genset when specific conditions require this. For example, if the ambient temperature increases so much that the cooling water coolers do not have enough cooling capacity. If the genset is not derated, there can be alarms and/or a shutdown. Three, independent derate functions are available.

The derating is based on the nominal power.

NOTE The derate function is typically used when cooling problems are expected.

9.7.1 Input selection

Each derate function can be assigned to one of the following inputs (using parameter 6241, 6251 or 6261):

Input	Comment
Multi-input 102 (slot #7) Multi-input 105 (slot #7) Multi-input 108 (slot #7)	0-40V DC 4-20 mA Pt100/1000 RMI Digital
Analogue input (M15.X)	4-20 mA
Multi-input (M16.X)	0-5V DC 4-20 mA Pt100
External analogue input (H12.X)	
EIC (only with option H12)	EIC cooling water temp. (SPN 110) EIC Oil temp. (SPN 175) EIC Ambient temp. (SPN 171) EIC Intercool temp. (SPN 52) EIC Fuel temp. (SPN 174) EIC Derate request (SPN 3644)*
M-Logic	If *M-Logic, Output, Command, Derate Pnom 1/2/3* is activated, the AGC uses the value in parameter 6246 for derating.

NOTE * See EIC derate. Alternatively, you can enable parameter 7551 to activate derate requests directly from the EIC.

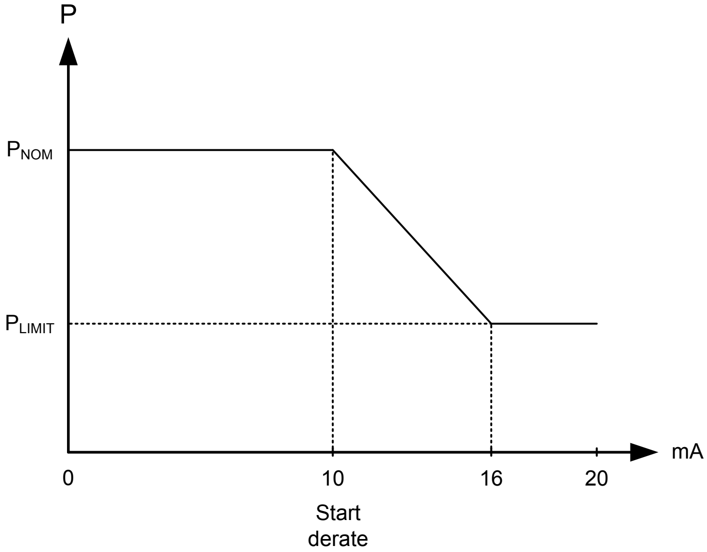
NOTE If more than one derate function and/or parameter 7551 are enabled, the AGC uses the lowest calculated derate power.

9.7.2 Derate parameters

These parameters define the derate function:

- **Start derate at (6242/6252/6262)**: The value where the derating starts. The input selection (6241/6251/6261) determines the units.
- **Derate slope (6243/6253/6263)**: Used to calculate the power, based on the input (percent per unit). For example, if a 4-20 mA input is used, then the derating is in %/mA. If the Pt100/Pt1000/RMI input is used, then the derating is in %/ °C.
- **Derate limit (6246/6256/6266)**: This is the lower power derating limit, shown by P(limit) below.

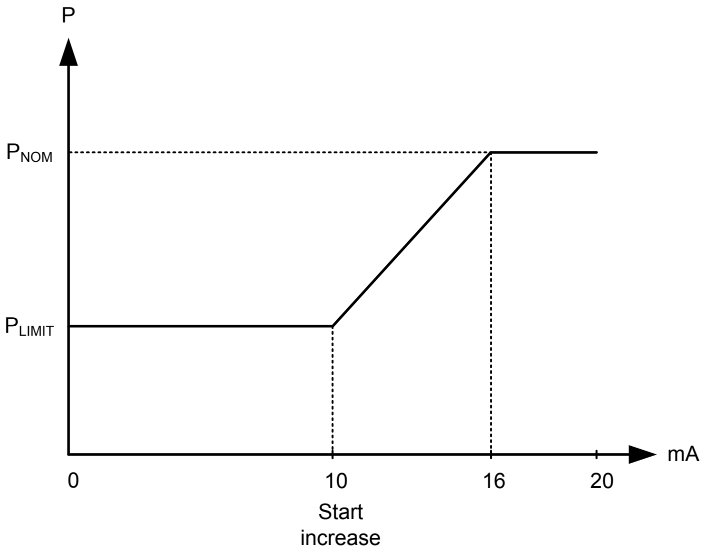
Inverse derating example



9.7.3 Derate characteristic

The derating can be proportional or inverse.

Proportional derating example



Use *Enable* in parameter 6246/6256/6266 to select the derate characteristic:

- Enable OFF: Inverse. A higher control value gives a lower power.
- Enable ON: Proportional. A higher control value gives a higher power.

9.7.4 EIC derate

NOTE This requires option H12.

The AGC can use a value from the EIC for derating. Specifically, the AGC uses the Engine Derate Request (PGN 64914/0xFD92, SPN 3644) to calculate the maximum genset power.

There are two options for EIC derating.

EIC derate with derating function

Using parameter 6241, 6251 or 6261, select *EIC Derate request (SPN 3644)*.

To calculate the derated power, the AGC uses the value from the EIC in the derate function.

EIC derate using parameter 7551

Enable parameter 7551 to use the EIC value *Engine Derate Request (that is, SPN 3644)* as the derated power in the AGC. That is, the EIC value is used directly, without a derate calculation.

9.8 Dynamic frequency response

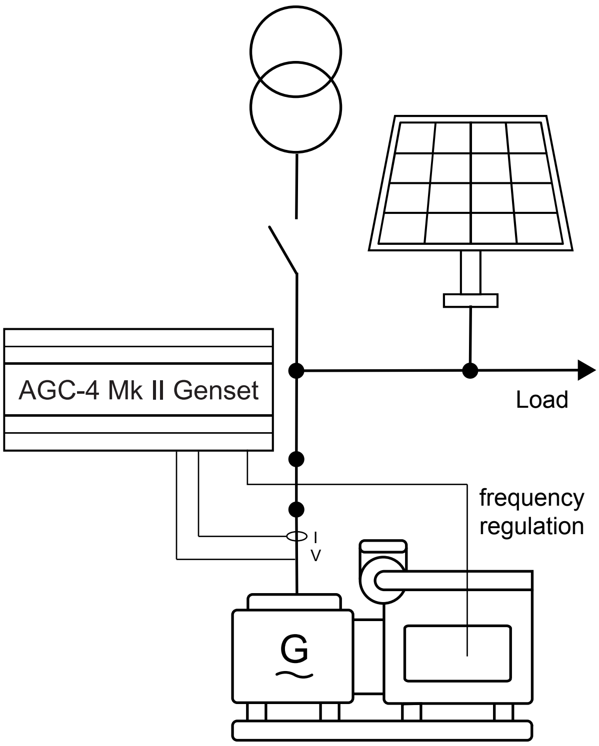
You can use the dynamic frequency response (DFR) function to automatically adjust the genset frequency set point, based on the genset load. DFR is designed for systems where photovoltaic (PV) power and a genset are connected. Without DFR, when the PV conditions are good, the PV can produce too much power. The excess PV power can then force the genset to run at low or reverse power. When DFR is active, DFR checks whether a mains is connected. If the genset is in island operation, DFR monitors the power from the genset, and automatically adjusts the genset frequency set point.

With DFR, if the genset power is low, the controller increases the busbar frequency. The PV should respond to the higher frequency by producing less power. DFR therefore protects the genset from loads that are too low (including reverse power).

The controller can regularly check whether frequency affects genset power. These checks stop the DFR from raising the busbar frequency when the PV is inactive (for example, at night). If frequency does not affect genset power, the reference frequency is used as the set point.

DFR can be activated using the setting in the utility software. When DRF is activated in the utility software, it can be operated using M-Logic.

System example



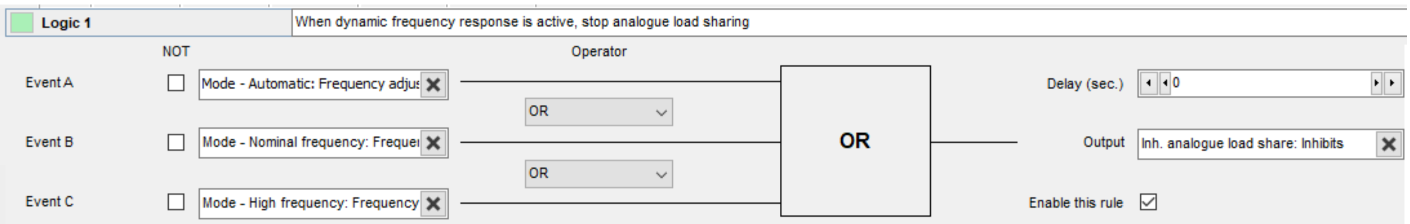
DFR uses the standard genset controller's connections. DFR uses the measurements from the voltage and current terminals to calculate the genset power. DFR uses governor regulation to regulate the busbar frequency.

No mains connection

If there is a mains connection, the controller does not use DFR. The controller automatically checks that the genset is in island operation.

No analogue load sharing

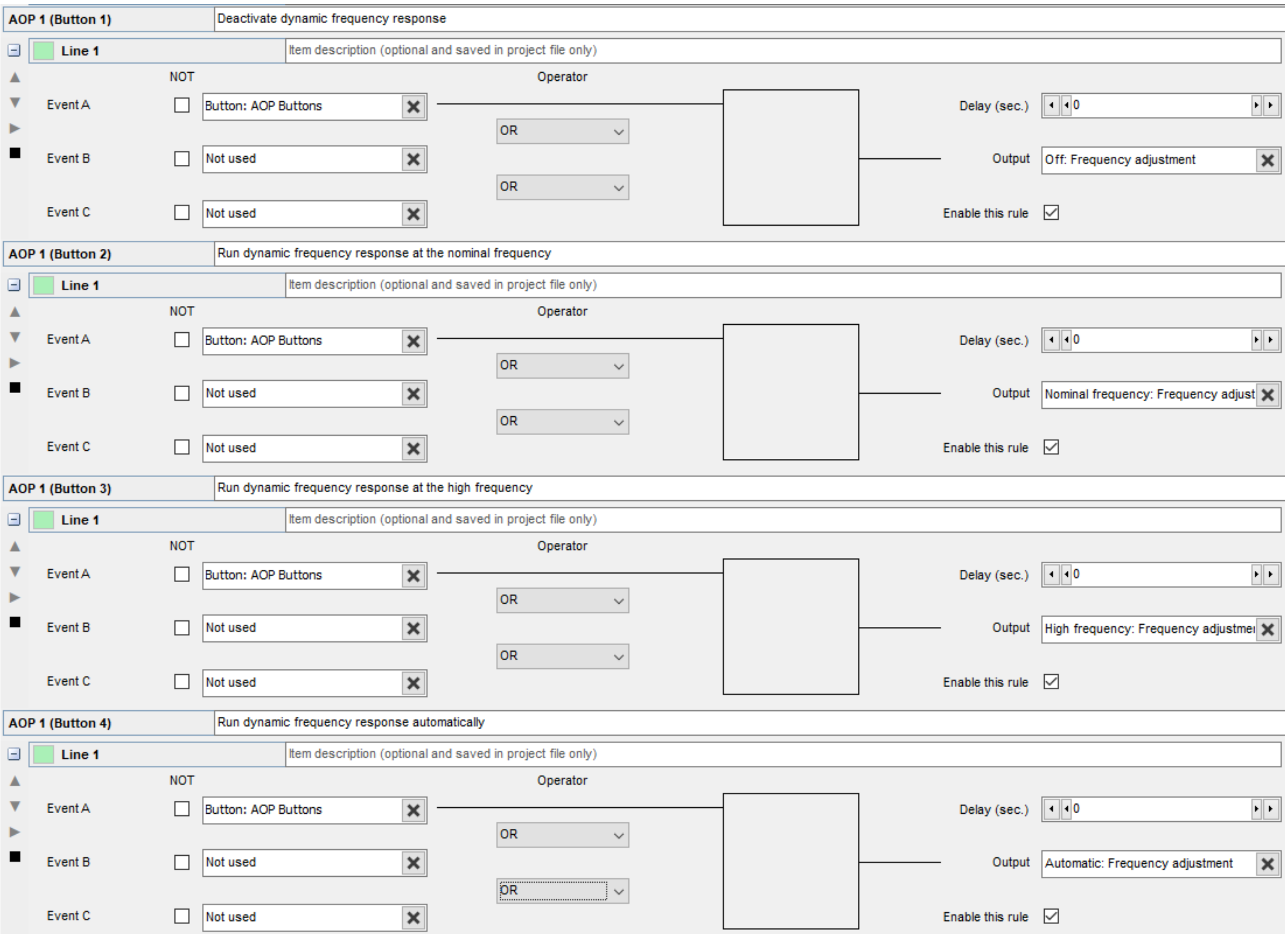
DFR does not work if analogue load sharing is active. You can use M-Logic to inhibit P/Q load sharing.



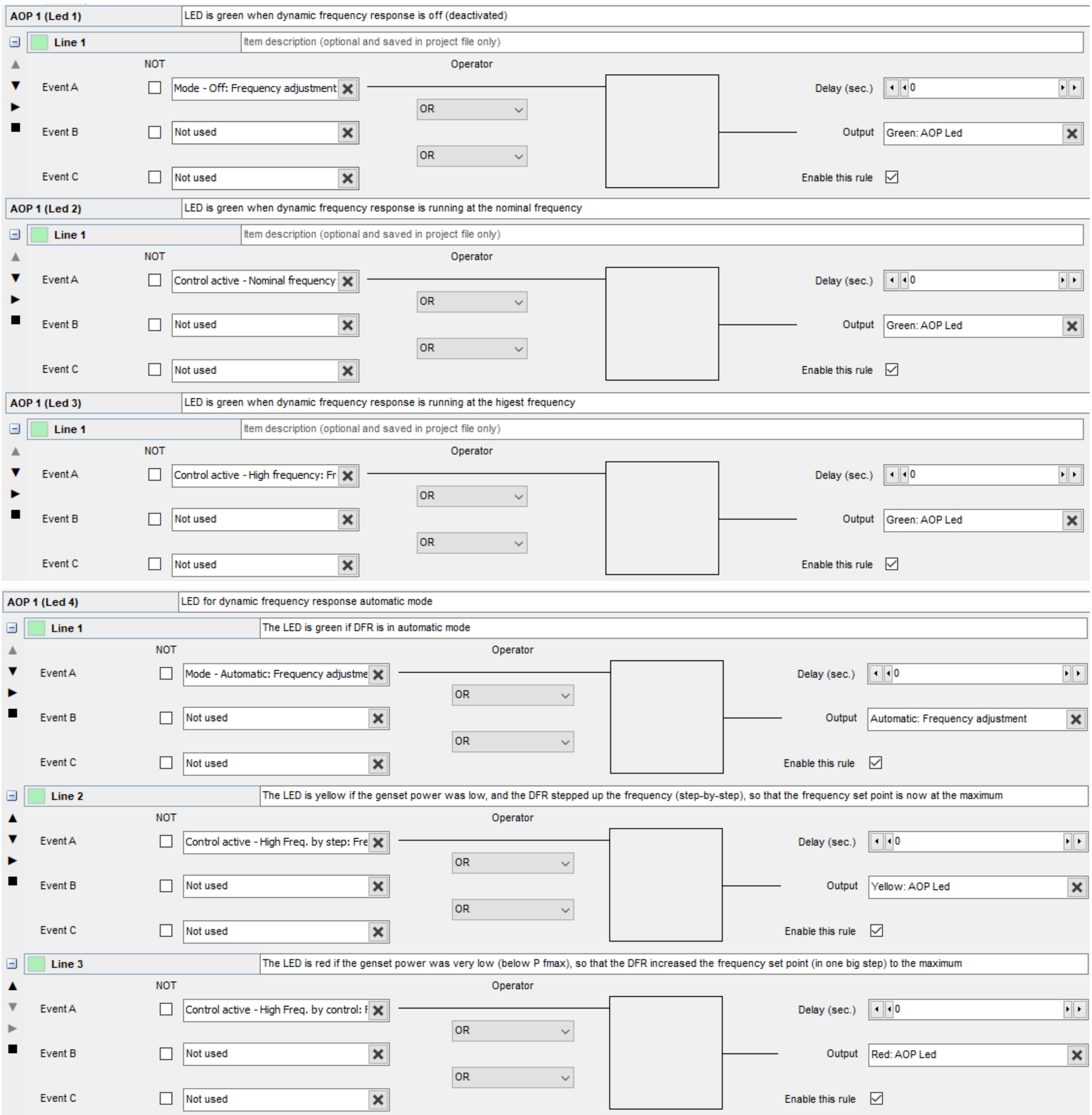
Automatic adjustment of power threshold 1

To ensure smooth control, the controller automatically adjusts the first power threshold. The initial value is *Minimum power* **P1** (also known as *Power threshold 1*). The controller does not adjust **P1** below the *Minimum power limit* **P1 Limit** (also known as *Limit power threshold 1*).

Using AOP buttons to operate DFR (example)



Using AOP LEDs to monitor DFR (example)



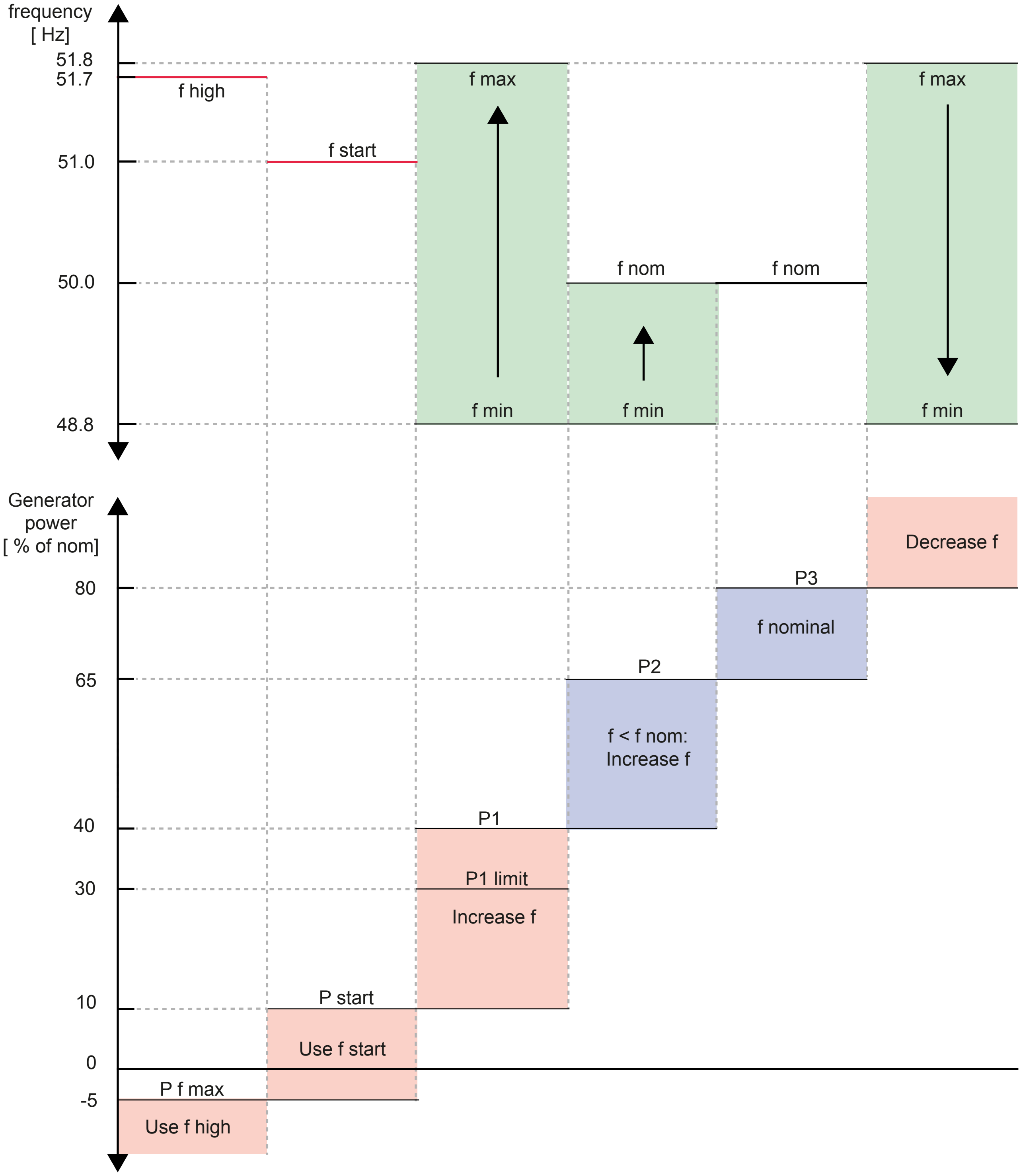
9.8.1 Settings

Utility software > Advanced protection > DFR

Name	Range	Default	Details
Dynamic frequency response	OFF ON	OFF	To activate DFR, select ON.
Min frequency (f min)	48 to 60 Hz	48.8 Hz	The lowest frequency set point for DFR.
Max frequency (f max)	50 to 62 Hz	51.8 Hz	The highest frequency set point for DFR.
Control end req	50 to 62 Hz	51.4 Hz	The highest frequency set point for high frequency by step. If the genset power is still low and a higher frequency is needed, the controller uses *f max*.

Name	Range	Default	Details
High frequency (f high)	50 to 62 Hz	51.7 Hz	The frequency set point for high frequency mode (activated by very low power).
Start frequency (f start)	50 to 62 Hz	51 Hz	The first frequency set point when the genset power goes below *P start*.
Frequency reference	50 to 61 Hz	50.1 Hz	The fallback frequency set point. DFR uses this set point when frequency changes do not affect the genset power. This set point must not be less than the nominal frequency.
Frequency step	0.1 to 0.5 Hz	0.1 Hz	This setting is used for frequency step control.
Period time (t step)	1 to 20 s	10 s	The minimum time between frequency step changes.
Start below power (P start)	0 to 30 %	10 % of nominal genset power	DFR starts frequency regulation if the genset power is below this value.
Max freq below power (P fmax)	-10 to 10 %	-5 % of nominal genset power	DFR uses *f max* as the frequency set point if the genset power is below this value.
Minimum power (P min)	10 to 70 %	40 % of nominal genset power	Also known as P1. Below P1, DFR increases the frequency set point. Between P1 and P2, DFR only increases the frequency set point if the frequency is below the nominal frequency.
Min power limit	0 to 40 %	30 % of nominal genset power	Also known as P1 limit. The limit for the automatic adjustment of P1. See below for details.
Power reference	20 to 80 %	65 % of nominal genset power	Also known as P2. Between P2 and P3, DFR regulates the frequency to the nominal frequency.
Maximum power (P max)	70 to 99 %	80 % of nominal genset power	Also known as P3. Above P3, DFR only decreases the frequency set point if the frequency is above the nominal frequency. The frequency set point is not decreased below f min.
Test signal period time	0 to 600 s	300 s	The time between tests (making a small frequency change to test the effect on the system power).
Test signal freq step	0.1 to 1 Hz	0.2 Hz	The change in frequency used in the tests.

Power and frequency settings example



9.8.2 M-Logic

Frequency adjustment

`Output > Frequency adjustment`

Description	Notes
Off	Deactivate the dynamic frequency response function (the controller does not adjust the frequency set point).
Nominal frequency	Dynamic frequency response controls the frequency at the nominal frequency.

Description	Notes
High frequency	Controls the frequency at the dynamic frequency response *High frequency* setting.
Automatic	Automatically select the dynamic frequency response mode. Activate the suitable dynamic frequency response control.

Frequency adjustment

`Events > Frequency adjustment`

Description	Notes
Control inactive	The dynamic frequency response function does not control the frequency.
Control active - Nominal frequency	The dynamic frequency response function controls the frequency at the *Frequency reference* setting.
Control active - High frequency	The dynamic frequency response function controls the frequency at the *High frequency* setting.
Control active	The dynamic frequency response function controls the frequency.
Control active - High Freq. by step	The genset power was low. The dynamic frequency response function therefore increased the frequency set point in steps, so that the frequency set point is now at the maximum.
Control active - High Freq. by control	The genset power was very low (P f max). The dynamic frequency response function therefore increased (in one big step) the frequency set point to the maximum.
Mode - Off	The dynamic frequency response function is not activated.
Mode - Nominal frequency	The dynamic frequency response function is activated. The controller controls the frequency at the nominal frequency.
Mode - High frequency	The dynamic frequency response function is activated. The controller controls the frequency at the *High frequency* setting.
Mode - Automatic	The dynamic frequency response function is activated. The controller automatically selects the mode and activates suitable control.

9.9 Trip of non-essential load (NEL)

9.9.1 Trip of NEL

NOTE The two terms "trip of non-essential load" and "load shedding" describe the same function.

The trip of Non Essential Load (NEL) groups (load shedding) is carried out to protect the busbar against an imminent blackout due to either a high load/current or overload on a generator set or a low busbar frequency.

The controller can trip three NEL groups due to:
- The measured load of the generator set (high load and overload)
- The measured current of the generator set
- The measured frequency at the busbar

The load groups are tripped individually. This means that the trip of load group 1 has no direct influence on the trip of load group 2. Only the measurement of either the busbar frequency or the load/current on the generator set can trip the load groups.

Trip of the NEL groups due to the load of a running generator set will reduce the load on the busbar and thus reduce the load percentage on the running generator set. This may prevent a possible blackout at the busbar caused by an overload on the running generator set. The current trip will be selected in case of inductive loads and unstable power factor (PF <0.7) where the current is increased.

Trip of the NEL groups due to a low busbar frequency will reduce the real power load at the busbar and thus reduce the load percentage on the generator set. This may prevent a possible blackout at the busbar.

NOTE For output setup, please refer to the description of outputs.

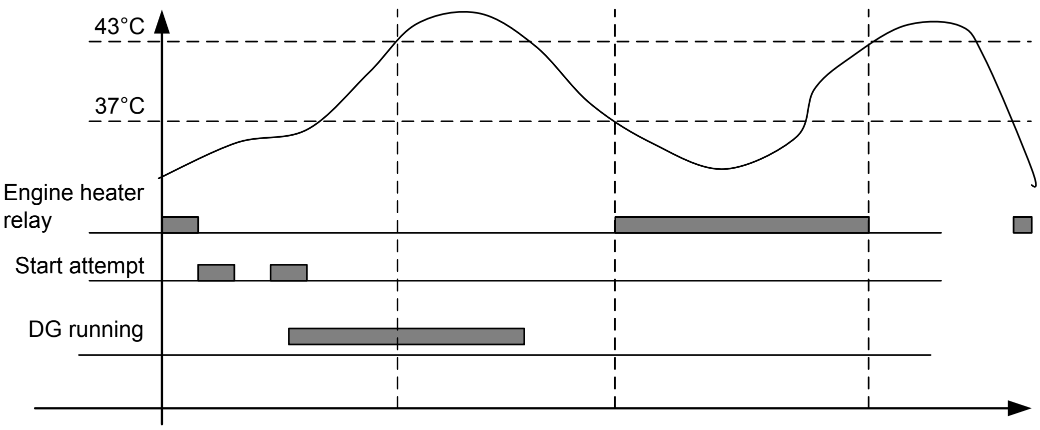
9.10 Engine heater

This function is used to control the temperature of the engine. A sensor measuring the cooling water temperature is used to activate an external heating system to keep the engine at a minimum temperature.

The set points adjusted in menu 6320 are:

- Set point: This set point +/- the hysteresis is the start and stop points for the engine heater.
- Output A: The relay output for the engine heater.
- Input type: Multi-input to be used for temperature measurement.
- Hysteresis: This decides how big a deviation from the set point is needed to activate/deactivate the engine heater.
- Enable: Enables the engine heater function.

Principle diagram



NOTE The engine heater function is only active when the engine is stopped.

9.10.1 Engine heater alarm

If the temperature keeps dropping after the start set point has been exceeded, an alarm will be raised if configured in menu 6330.

9.11 Pump logic

9.11.1 Fuel pump logic

The fuel pump logic is used to start and stop the fuel supply pump to keep the fuel in the service tank at the required level. The fuel level is detected from one of the three multi-inputs.

Parameters

Parameter	Name	Range	Default	Details
6551	Fuel pump logic	0 to 100 % 1 to 10 s	20 % 1 s	Fuel transfer pump start point.
6552	Fuel pump logic	0 to 100 %	80 %	Fuel transfer pump stop point.
6553	Fuel fill check	0.1 to 999.9 s Fail classes	60 s Warning	Fuel transfer pump alarm timer and fail class. The alarm is activated if the fuel pump relay is activated, but the fuel level does not increase by 2 % within the delay time.
6554	Fuel pump logic	Multi input [102/105/108], Ext. Ana. In [1 to 8], Auto detection	Auto detection	The multi-input or external analogue input for the fuel level sensor. Configure the input in the utility software under *I/O & Hardware setup*. Select the multi-input if 4-20 mA is used. Select *Auto detection* if a multi input with RMI fuel level is used.

Relay output

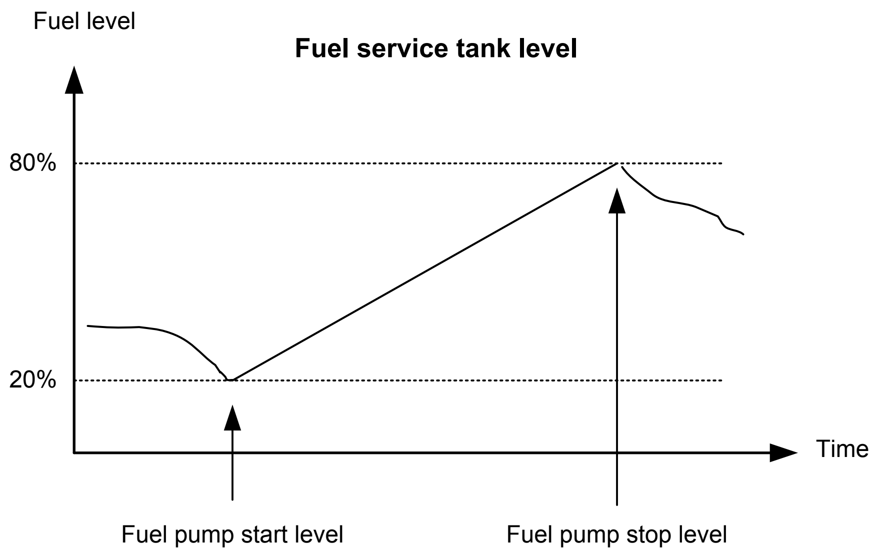
In the utility software under *I/O & Hardware setup*, select the output relay to control the fuel pump, as shown in the following example. If you do not want an alarm whenever the output is activated, configure the output relay as a limit relay.

The controller activates the relay when the fuel level is below the start limit. The controller deactivates the relay when the fuel level is above the stop limit.

NOTE The fuel pump relay can be activated using M-Logic (`Output > Command > Activate Fuel Pump`).

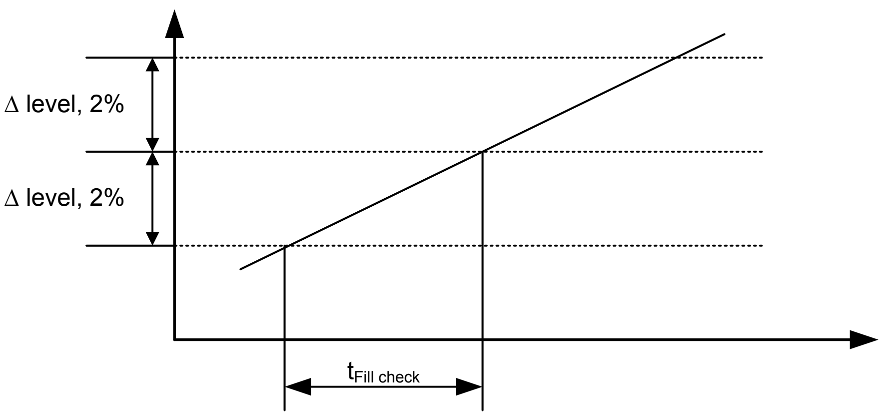
How it works

The diagram below shows how the fuel pump is started when the fuel level is 20 % and stopped again when the level is 80 %.



Fuel fill check

When the fuel pump is running, the fuel level must increase by 2 % within the **Fuel fill check** timer set in menu 6553. If the fuel level does not increase by 2 %, the controller deactivates the fuel pump relay and activates a **Fuel fill alarm**.



NOTE The level increase is fixed at 2 % and cannot be changed.

Fuel tank level and volume

You can set the capacity of the day tank in parameter 6911. The controller uses this value and the fuel level to calculate the fuel volume. The fuel volume is shown in the utility software in *Application supervision, Genset data, General*.

9.11.2 DEF pump logic

The DEF pump logic can start and stop the DEF pump to keep the DEF at the required level. For this function, engine interface communication (EIC) must provide the DEF level. If the EIC cannot provide the DEF level, you can use the generic fluid pump logic instead.

Parameters

Parameter	Name	Range	Default	Details
6721	DEF pump log. start	0 to 100 % 1 to 10 s	20 % 1 s	DEF transfer pump start point.
6722	DEF pump log. stop	0 to 100 %	80 %	DEF transfer pump stop point.
6723	DEF fill check	0.1 to 999.9 s Fail classes	60 s Warning	DEF transfer pump alarm timer and fail class. The alarm is activated if the DEF pump relay is activated, but the DEF level

Parameter	Name	Range	Default	Details
				does not increase by the DEF fill slope (see 6724) within the delay time.
6724	DEF fill slope	1 to 10 %	2 %	When the DEF pump relay is activated, this is the amount by which the DEF level must increase in the time defined in 6723.

Relay output

In the utility software under *I/O & Hardware setup*, select the output relay to control the DEF pump, as shown in the following example. If you do not want an alarm whenever the output is activated, configure the output relay as a limit relay.

The controller activates the relay when the DEF level is below the start limit. The controller deactivates the relay when the DEF level is above the stop limit.

NOTE The DEF pump relay can be activated using M-Logic (`Output > Command > Activate DEF Pump`).

9.11.3 Generic pump logic

The fluid pump logic can start and stop a pump to keep any fluid at the required level.

Parameters

Parameter	Name	Range	Default	Details
6731	Fluid pump start	0 to 100 % 1 to 10 s	20 % 1 s	Fluid transfer pump start point.
6732	Fluid pump stop	0 to 100 %	80 %	Fluid transfer pump stop point.
6733	Fluid check	0.1 to 999.9 s Fail classes	60 s Warning	Fluid transfer pump alarm timer and fail class. The alarm is activated if the fluid pump relay is activated, but the fluid level does not increase by the fluid fill slope (see 6735) within the delay time.
6734	Fluid pump log.	Multi input [102/105/108], Ext. Ana. In [1 to 8]	Multi input 102	Select the analogue input for the fluid level. Configure the input in the utility software under *I/O & Hardware setup*.
6735	Fluid fill slope	1 to 10 %	2 %	When the fluid pump relay is activated, this is the amount by which the fluid level must increase in the time defined in 6733.

Relay output

In the utility software under *I/O & Hardware setup*, select the output relay to control the fluid pump, as shown in the following example. If you do not want an alarm whenever the output is activated, configure the output relay as a limit relay.

The controller activates the relay when the fluid level is below the start limit. The controller deactivates the relay when the fluid level is above the stop limit.

NOTE The fluid pump relay can be activated using M-Logic (`Output > Command > Activate Generic Pump`).

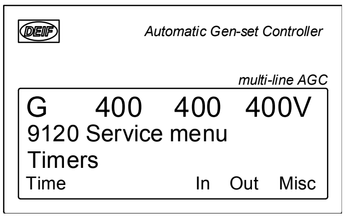
9.12 Service menu

The purpose of the service menu is to give information about the present operating condition of the genset. The service menu is entered using the "JUMP" push-button (9120 Service menu).

Use the service menu for easy troubleshooting in connection with the event log.

Entry window

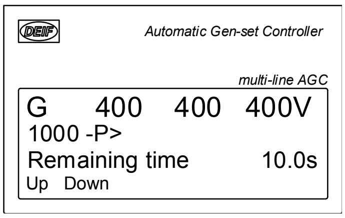
The entry shows the possible selections in the service menu.



Available selections

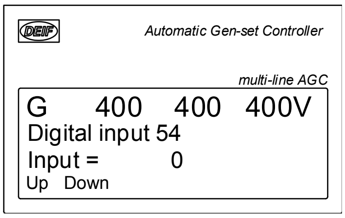
Time

Shows the alarm timer and the remaining time. The indicated remaining time is minimum remaining time. The timer will count downwards when the set point has been exceeded.



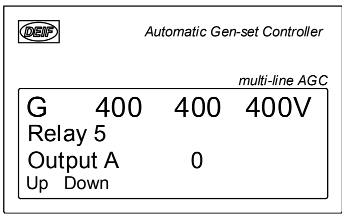
IN (digital input)

Shows the status of the digital inputs.



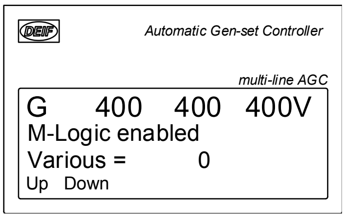
OUT (digital output)

Shows the status of the digital outputs.



MISC (miscellaneous)

Shows miscellaneous messages.



9.13 Service timers

The controller can monitor the maintenance intervals. Four service timers are available to cover different intervals. The service timers are set up in menus 6110, 6120, 6300 and 6310.

The function is based on running hours. When the adjusted time expires, the controller will display an alarm. The running hours is counting when the running feedback is present.

Set points available in menus 6110, 6120, 6300 and 6310:

- Enable: Enable/disable the alarm function.
- Running hours: The number of running hours to activate the alarm. The service timer alarm will be activated as soon as the running hours have been reached.
- Day: The number of days to activate the alarm – if the running hours are not reached before this number of days, the alarm will still be activated. The service timer alarm will be activated at 8:00 AM on the day the alarm expires.
- Fail class: The fail class of the alarm.
- Output A: Relay to be activated when the alarm is activated.
- Reset: Enabling this will reset the service timer to zero. This must be done when the alarm is activated.

9.14 Command timers

The purpose of the command timers is to be able to for example start and stop the genset automatically at specific times each weekday or certain weekdays. If auto mode is activated, this function is available in island operation, load takeover, mains power export and fixed power operation. Up to four command timers can be used for start and stop for instance. The command timers are available in M-Logic and can be used for other purposes than starting and stopping the genset automatically. Each command timer can be set for the following time periods:

- Individual days (MO, TU, WE, TH, FR, SA, SU)
- MO, TU, WE, TH
- MO, TU, WE, TH, FR
- MO, TU, WE, TH, FR, SA, SU
- SA, SU

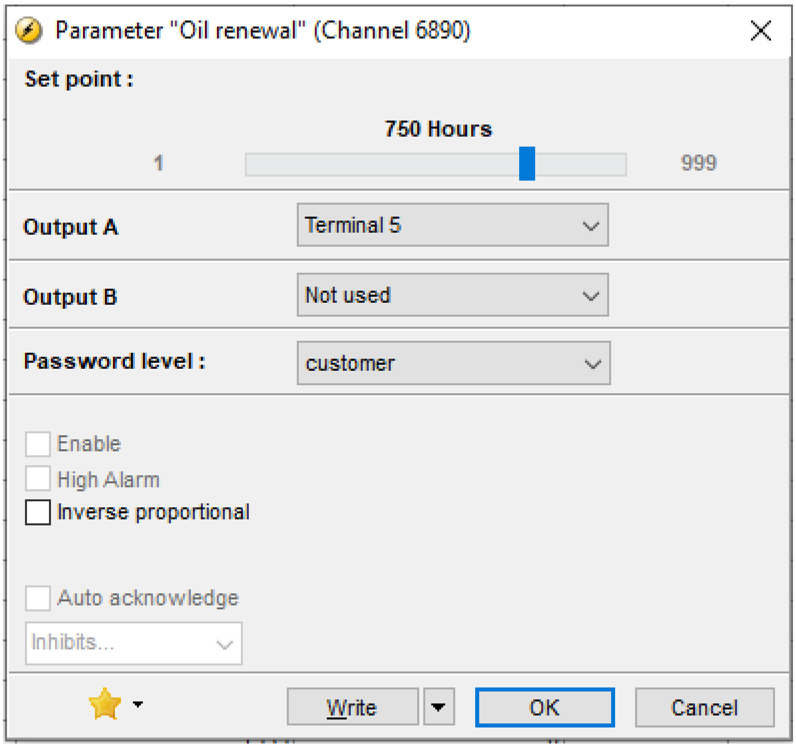
NOTE To start in AUTO mode, the "Auto start/stop" command can be programmed in M-Logic or in the input settings.
NOTE The time-dependent commands are flags that are raised when the command timer is in the active period.

9.15 Oil renewal function

The purpose of the oil renewal function is to give the possibility to exchange a small portion of the lubricating oil of the engine with fresh or new oil. This means that the quality of the oil is kept at a satisfactory level without significant degrading of the oil (for example, contamination and TBN value) in the entire period between the oil changes.

The time interval between the oil changes is assumed to be 1000 hours of operation. The renewal function will read the engine hours from the engine interface communication (EIC). The running hours counter in the controller is only used if the EIC counter is not available.

The function in the controller is to activate a relay under defined conditions. Then the relay must be used for the oil renewal system (not part of the DEIF scope of supply) where lubricating oil is removed and added to the engine. Any freely configurable relay is available for this feature. In parameter 6890 a set point is available, which can be set between 1 and 999 hours to define when the relay should close, and it is possible to choose which relay should be used. Furthermore, this parameter can be inversed, meaning that the relay will remain closed until the set point is reached.



When the running hours counter has reached 1000 hours, the controller will reset the hours just for the oil renewal function. If, for example, the set point has been set to 750 hours and inverse is not enabled, the relay will close at 750 hours and remain closed until 1000 hours is reached, and then the hours counter starts from 0 hours again.

9.16 Breaker functions

9.16.1 Breaker types

There are five possible selections for the setting of breaker type for both mains breaker and generator breaker.

Continuous NE and Continuous ND

This type of signal is most often used combined with a contactor. When using this type of signal, the AGC will only use the close breaker relays. The relay will be closed for closing of the contactor and will be opened for opening of the contactor. The open relay can be used for other purposes. Continuous NE is a normally energised signal, and Continuous ND is a normally de-energised signal.

Pulse

This type of signal is most often used combined with circuit breaker. With the setting pulse, the AGC will use the close command and the open command relay. The close breaker relay will close for a short time for closing of the circuit breaker. The open breaker relay will close for a short time for opening of the breaker.

External/ATS no control

This type of signal is used to indicate the position of the breaker, but the breaker is not controlled by the AGC.

Compact

This type of signal will most often be used combined with a compact breaker, a direct controlled motor driven breaker. With the setting compact, the AGC will use the close command and the open command relay. The close breaker relay will close for a short time for the compact breaker to close. The breaker off relay will close for the compact breaker to open and hold it closed long enough for the motor in the breaker to recharge the breaker. If the compact breaker is tripped externally, it is recharged automatically before next closing.

NOTE If compact breaker is selected, the length of the breaker open signal can be adjusted. This can be done in menu 2160/2200.

9.16.2 Breaker position failure

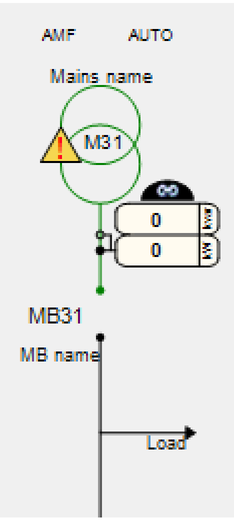
At all times, the controller must get feedback from the breaker about its position, that is, whether it is opened or closed.

The position failure alarm is activated:

- When the controller is not getting either an open or close feedback from the breaker.
- When the controller is getting both open and close feedbacks from the breaker simultaneously.

Controller	Breaker	Parameters
Genset	Generator Breaker	GB Pos fail (menu 2180)
Genset	Mains Breaker	MB Pos fail (menu 2220)
Mains	Tie Breaker	TB Position fail (menu 2180)
Mains	Mains Breaker	MB Pos fail (menu 2220)
BTB	Bus Tie Breaker	BTB Position fail (menu 2180)

When a controller has position failure alarm on its breaker, in the application supervision the position failure is highlighted as shown below.



NOTE By default, the fail class of the position failure alarm is *Warning*. This allows the breaker to retry the action that it was doing before the alarm was activated.

9.16.3 Breaker spring load time

To avoid breaker close failures in situations where breaker ON command is given before the breaker spring has been loaded, the spring load time can be adjusted for GB/TB and MB.

The following describes a situation where you risk getting a close failure:

1. The genset is in auto mode, the auto start/stop input is active, the genset is running and the GB is closed.
2. The auto start/stop input is deactivated, the stop sequence is executed and the GB is opened.
3. If the auto start/stop input is activated again before the stop sequence is finished, the GB will give a GB close failure as the GB needs time to load the spring before it is ready to close.

Different breaker types are used, and therefore there are two available solutions:

1. Timer-controlled: A load time set point for the GB/TB and MB control for breakers with no feedback indicating that the spring is loaded. After the breaker has been opened it will not be allowed to close again before the delay has expired. The set points are found in menus 6230, 7080 and 8190. On the AGC Mains controller (option G5), the spring load feedback from the tie breaker can be connected instead of the GB spring load feedback.
2. Digital input: Two configurable inputs to be used for feedbacks from the breakers: One for GB/TB spring loaded and one for MB spring loaded. After the breaker has been opened it will not be allowed to close again before the configured inputs are active. The inputs are configured in the utility software. When the timers are counting, the remaining time is shown in the display.

If the two solutions are used together, both requirements are to be met before closing of the breaker is allowed.

Breaker LED indication

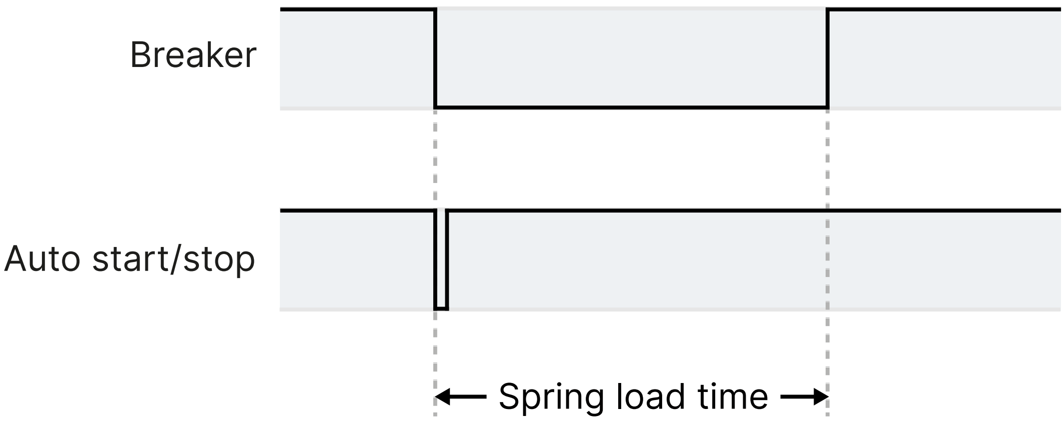
To alert the user that the breaker close sequence has been initiated but is waiting for permission to give the close command, the LED indication for the breaker will be flashing yellow in this case.

If the breaker needs time to reload the spring after it has opened, then the AGC can take this delay into account. This can be controlled through timers in the AGC or through digital feedbacks from the breaker, depending on the breaker type.

9.16.4 Breaker spring load time principle

The diagram shows an example where a single AGC in island operation is controlled by the AUTO start/stop input.

This is what happens: When the AUTO start/stop input deactivates, the GB opens. The AUTO start/stop is reactivated immediately after the GB has opened, for example by the operator through a switch in the switchboard. However, the AGC waits a while before it issues the close signal again, because the spring load time must expire (or the digital input must be activated - not shown in this example). Then the AGC issues the close signal.



9.16.5 Racked out breaker

Racked out breaker is a function which is used when the breaker's test mode is active or when the breaker is out for maintenance. The feature “racked out breaker” informs the system that the physical position of the breaker is open no matter the position feedback of the actual breaker, which makes it possible to operate the racked out breaker without interfering with the rest of the system.

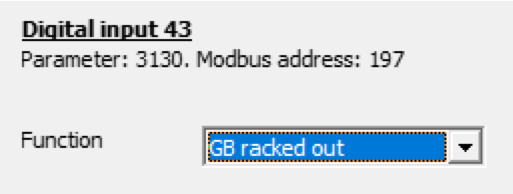
NOTE When the function *Racked Out Breaker* is activated, the specific controller expects the breaker to physically be disconnected from the busbar, and thereby the breaker can be opened and closed instantly without any synchronisation check no matter the busbar state.

When the breaker is out for maintenance, the position feedback might not be present on the controller which causes a *position failure* alarm, and while the breaker is in test mode, the technician might operate the breaker manually which causes a *breaker Ext. tripped* alarm.

If the above mentioned alarms are triggered while the *racked out breaker* is active, alarms are suppressed by changing the fail class of the specific alarms to *Warning*. This ensures that the alarm will not interfere with other breakers in the system.

A DG or mains controller that has the *breaker racked out* feature active, will inform the other controllers in the system that the breaker is open but also that the power source is not available on the busbar.

In the input list from the USW, the tag “breaker racked out” is assigned to specific inputs, see screen shot below.



NOTE Depending on the controller type, GB, TB, MB or BTB -*racked out* is shown in the input list.

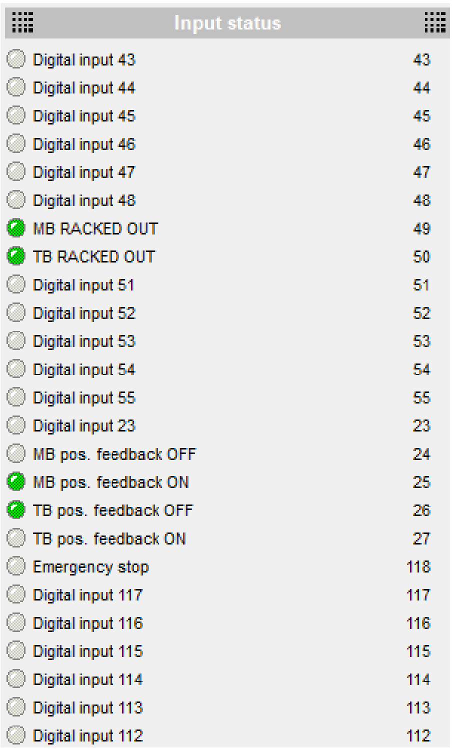
Several conditions have to be fulfilled before the “Racked out breaker” function will come active:

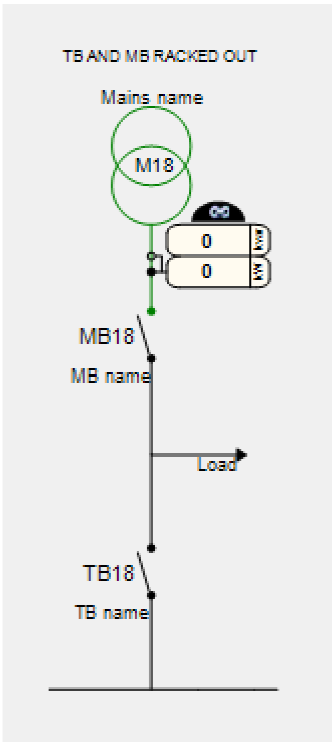
1. Controller should either be in semi-auto or manual running mode
2. *Breaker pos. feedback OFF* is active, or a position failure on the specific breaker is present
3. The input for racked out breaker is high

If all the above conditions are fulfilled, the status text and the USW will show “BREAKER RACKED OUT”.

NOTE If a *position failure* or *breaker ext. trip* occurs while the breaker is racked out and the input for the feature is high, the alarms will show but the fail class will be inhibited.

The pictures below shows a mains with both MB, and TB racked out, 1 feedback ON and 1 feedback OFF still it is recognised as an open signal while the breaker racked out input is high.





NOTE It is important to physically check that the breaker is actually racked out/disconnected from the busbar or is physically in the test position. When the racked out signal is active, no synchronisation is present, and if the breaker is not physically removed, a close command to the breaker from the controller could potentially connect a generator and a live BB out of sync.

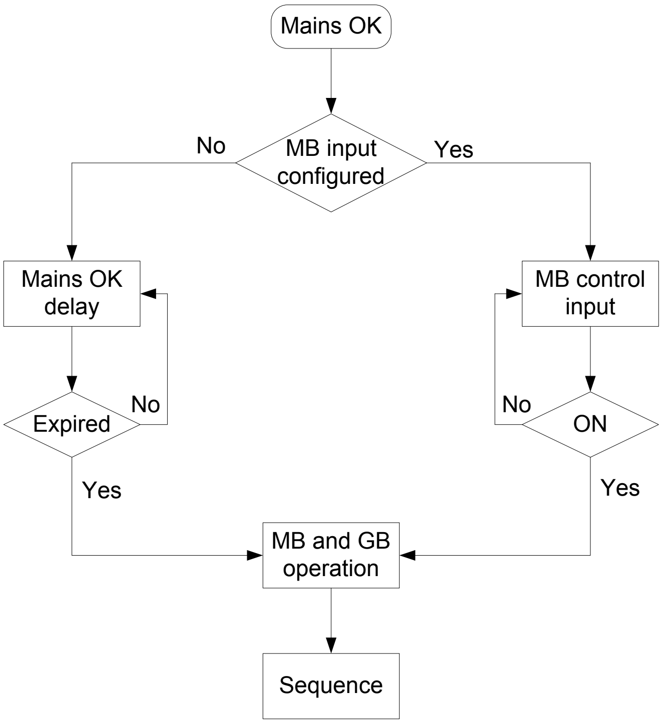
NOTE When a genset controller is in racked out breaker mode it will not be possible to use ground relay function. See **Option G5** for more information about ground relay.

9.17 Digital mains breaker control

The controller will normally execute the automatic mains failure sequence based on the settings adjusted in the system setup. Besides these settings it is possible to configure a digital input that can be used to control the mains return sequence. This input is the "mains OK" input. The purpose of this function is to let an external device or an operator control the mains return sequence. The external device can e.g. be a PLC.

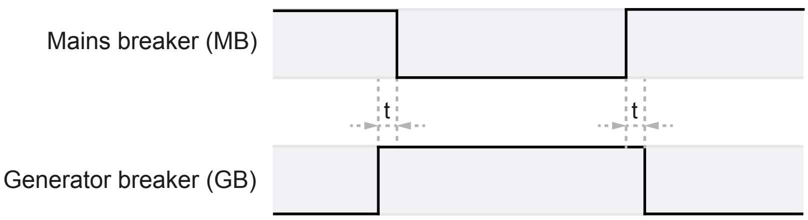
The flowchart below shows that if the input is configured, it needs to be activated (by a pulse) in order to initiate the mains return sequence. The load will continue on generator supply if the input is not activated.

The mains OK delay is not used at all when the "Mains OK" input is configured.



9.18 Short-time parallel

If *Overlap* (menu 2760) is *On*, the controller enforces a maximum paralleling time for the generator and mains supply. This is used to meet local requirements for short-time parallel. The overlap function is only available in automatic mains failure and load takeover modes.



When the generator breaker is closed, the mains breaker is opened automatically before the timer runs out (t). Similarly, when the mains breaker is closed, the generator breaker is opened before the timer runs out (t). The timer is configurable (0.10 to 99.90 seconds).

NOTE The timer is a maximum time. The two breakers are never both closed for longer than the set point.

NOTE If the function is used in a power management (option G5) application, for the AGC mains, the overlap is between the mains breaker and the tie breaker.

9.19 Frequency- or voltage-dependent droop

This droop function is a mains support function. It can be used when the genset is running parallel to the mains in the following modes: *Fixed power*, *Mains power export* and *Peak shaving*. If the frequency or voltage drops or rises due to instability of the mains, the curve for frequency- or voltage-dependent droop adjusts the power set point. The power set point is reduced for greater mains frequency or voltage. The power set point is increased when the mains frequency or voltage is lower than specified.

Parameters for frequency- or voltage-dependent droop

Parameter	Name	Range	Default	Description
7051	Contr. setting P	0 to 100 % of nominal power	100 %	Fixed power set point.
*	Deadband low (7121)	0 to 99.99 % of nominal frequency/voltage	0.4 %	Deadband for grid under-frequency or under-voltage.
*	Deadband high (7122)	0 to 99.99 % of nominal frequency/voltage	0.4 %	Deadband for grid over-frequency or over-voltage.
*	Hysteresis low (7123)	0 to 99.99 % of nominal frequency/voltage	99.89 %	Hysteresis for grid under-frequency or under-voltage. If this is set above deadband low, the hysteresis low is disabled.
*	Hysteresis high (7124)	0 to 99.99 % of nominal frequency/voltage	99.89 %	Hysteresis high in percentages of nominal frequency/voltage. If this is set above deadband high, the hysteresis high is disabled.
*	P min	0 to 20000 kW	24 kW**	Limit, minimum active power.
*	P max	0 to 20000 kW	480 kW**	Limit, maximum active power.
*	Slope low	-20000 to 20000 kW/%	96 kW/%**	Gradient during grid under-frequency or under-voltage. The setting determines the increase/decrease of power reference per percentage the actual value drops below nominal frequency/voltage.
*	Slope high	-20000 to 20000 kW/%	-96 kW/%**	Gradient during grid over-frequency or over-voltage. The setting determines the increase/decrease of power reference per percentage the actual value rises above nominal frequency/voltage.
*	Curve select	P(X1) N.A.	P(X1)	**P(X1)**: The X-axis is power.
*	Curve select	f U N.A.	f	**f**: The Y-axis is frequency. **U**: The Y-axis is voltage.
*	Curve enable	Disable Enable	Disable	Note that you the droop curve function is disabled by default. Change this parameter to enable it.
*	Recovery delay	0 to 3600 s	600 s	The timer starts when the grid frequency returns to the deadband. The controller uses power ramp 3 until this timer runs out, or the frequency moves out of the deadband.

Parameter	Name	Range	Default	Description
				Power ramp 3 is only available if you have Option A10. You can adjust it using parameters 2801 and 2802.
*	Calculation method	P momentary P installed	P installed	**P momentary**: Use actual P for the calculations. **P installed**: Use nominal P for the calculations.
*	Droop slope calculation method	Absolute Percentage	Absolute	Calculation method for the gradient.
*	Slope low	-100 to 100	5 % power/% f/U	Gradient during grid under-frequency or under-voltage.
*	Slope high	-100 to 100	-5 % power/% f/U	Gradient during grid over-frequency or over-voltage.

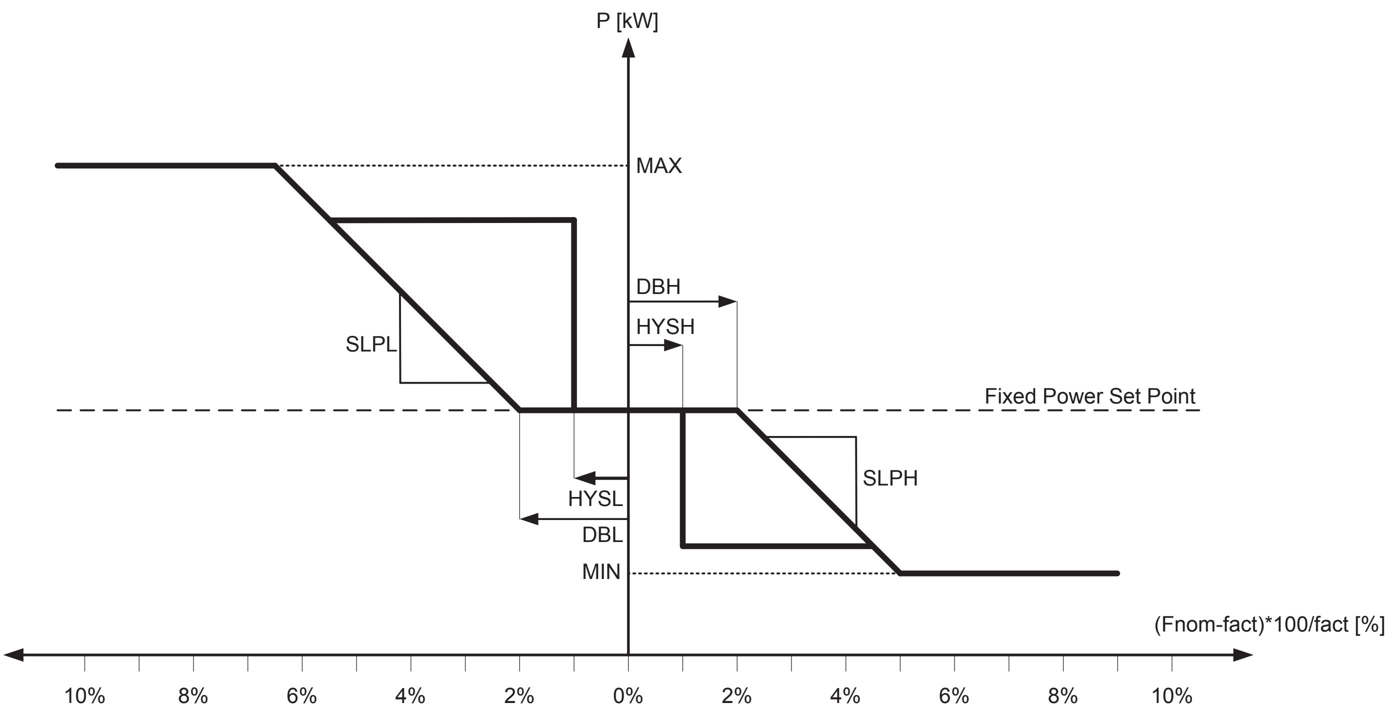
*Note: Use the USW to configure these parameters, under *Advanced Protection, Droop curve 1*.

**Note: If *Scaling* (parameter 9030) is *100 to 25 000 V*.

More information
Droop curve 1 is also used by Option A10. Compliance with new grid code rules is possible with AGC controllers and Option A10. For a more detailed explanation of droop curve 1, see **Over- and under-frequency-dependent active power** in **Option A10**.

Example

With a nominal frequency of 50 Hz and an actual frequency of 51.5 Hz, there is a deviation of 1.5 Hz which is equal to a 3 % deviation from the nominal setting. The genset will then droop to 400 kW according to the diagram below.



The droop curve can be specified within the area from P min to P max.

When droop is activated, the function is based on the actual value for power set point. If, for example, the function is activated during ramping and the actual power value is 200 kW, the droop is based on 200 kW as the *Fixed Power Set point* shown in the diagram.

The slopes (*Slope low (7133)* and *Slope high (7134)*) are used, as long as the mains frequency is moving away from the nominal setting. When the mains is starting to recover and the frequency is moving towards the nominal setting, the power set point waits to be restored until the frequency is within the hysteresis limits. If the hysteresis is disabled, the power set point is restored using the slope.

When drooping, the slopes are scaled based on size of the actual power at the droop start, compared to the specified nominal power. For example, if a genset of nominal 1000 kW is producing 500 kW when droop is activated, then only 50 % of the slope values will be used. For a nominal droop of 40 % per Hz, a 1000 kW (50 Hz) genset should be configured with slopes of 200 kW/%. If the genset only produces 500 kW when droop is activated, the actual slope is 100 kW/%.

If *Auto ramp selection* is enabled (parameter 2624), the secondary pair of ramps is used during frequency-dependent power droop. To prevent a new situation with faulty mains, in or after a situation with an unstable mains, slower ramps may be useful. The secondary ramps are automatically disabled again when the frequency-dependent power droop is no longer active, and the specified power set point is reached. If *Auto ramp selection* is disabled, it is only possible to activate the secondary ramps using M-Logic. Parameters used for the secondary ramps are stated in the table below.

Parameter	Name	Range	Default	Description
2616	Power ramp up 2	0.1 to 20 %/s	0.1 %/s	Slope of ramp 2 when ramping up.
2623	Power ramp down 2	0.1 to 20 %/s	0.1 %/s	Slope of ramp 2 when ramping down (not used for deload).
2624	Auto ramp selection	Enabled, Not enabled	Enabled	Activate or disable automatic selection of secondary ramps.

9.20 Power and cos phi offsets

9.20.1 Power offsets

This function is for making a power offset from Pnom, 3 offsets are available. It is possible to enable offsets in M-Logic, where offsets can be used as an event or an output where offsets can be activated or deactivated. The offset can be set in menus 7220 to 7225. The enabled power offsets will be added/subtracted from the fixed power set point in menu 7051, which refers to Pnom.

NOTE The adjusted fixed power set point will be kept within parameter 7023 *Minimum load*, and *Pnom*.

9.20.2 Cos phi offsets

This function is for making a cos phi offset from the fixed cos phi set point. 3 offsets are available. It is possible to enable offsets via M-Logic, where offsets can be used as an event or an output where offsets can be activated or deactivated. For example, *Output, Commands, Act. cos phi offset 1* and *Output, Commands, Deact. cosphi offset 1*. The cos phi offsets can be set in menu 7241-7245. The enabled cos phi offsets will be added/subtracted from the fixed cos phi set point in menu 7052.

NOTE The adjusted fixed cos phi set point will be kept within *Advanced Protection, Cosphi curve, Cosphi min set (7171)* and *Cosphi max set (7173)*.

NOTE The values in menu 7050 set the cos phi. This is not the power factor (PF) value displayed in the display. cos phi and PF are only equal if the AC waveform is a true sinusoidal wave.

9.21 RRCR external set point control

The grid can use a Radio Ripple Control Receiver (RRCR) for load management. The AGC can use the RRCR signals for power and reactive power regulation.

You can use four binary inputs (from an external RRCR) to configure 16 signal combinations. Each of the 16 signal combinations can used for a set point for *Power*, and a set point for *Reactive Power* or *cos phi*.

You can also make combined set points, for example, *Power* and *Reactive Power*, using the same inputs.

For feedback to the RRCR, you can use four relay outputs to configure 16 signal combinations. This feedback can only be used to represent the *Power* set point.

NOTE As an alternative to RRCR, the controller can use Modbus or analogue inputs for load management.

9.21.1 RRCR configuration

Use the Utility Software to configure the controller response to RRCR signals.

Configure the inputs in M-Logic

Use M-Logic to define the four binary inputs. All four inputs must be defined for RRCR to work. Select the inputs under *Output*, *Power Limit Inputs*, *Power Limit Input [01 to 04]*.

Figure 9.2 RRCR input example: DI 23 activates RRCR input I1

Configure the RRCR inputs for power set point inputs

Select the *RRCR* icon in the Utility Software task bar: . The **RRCR** window opens.

Figure 9.3 Example of RRCR for power set point inputs

RRCR Power set point inputs example

As the figure shows, the power set point inputs for RRCR are enabled.

When only input 1 is activated, the controller power set point is 0 %.
When only input 2 is activated, the controller power set point is 30 %.
When only input 3 is activated, the controller power set point is 60 %.
When only input 4 is activated, the controller power set point is 100 %.

For all other RRCR input combinations, the controller power set point is 0 %.

The RRCR inputs do not control the Q or cosphi set point.

The 16 input combinations are shown on the left of the window (red box). You cannot change these.

RRCR is *Enabled* (*Disabled* by default) using *Power Set point Inputs* (blue box).

For each input combination, under *P [%]* (black box), choose the required power set point.

Under *P Select* (orange box), select *P* for the controller to use *P [%]* as the set point for regulation. If *P Select* is *Off*, that RRCR input combination cannot be used for the power set point.

Configure the RRCR inputs for Q or cos phi set point inputs

- Under *Q [%]* (green box), choose the required reactive power set points. Note that *Q [%]* must be negative for capacitive set points.
- Under *Cosphi* (purple box), choose the required cos phi set points.
- Under *Excitation* (yellow box), select *Inductive* or *Capacitive* for cos phi. Note that the selection here does not affect the Q set point.
- Under *Q Select*, select the regulation *Off*, *Q* or *Cosphi*. If *Off* is chosen, there is neither reactive power nor cos phi regulation.

Configure the outputs in M-Logic

You can also use M-Logic to define the optional outputs. Select the outputs under *Events, Power Limit Outputs, Power Limit Output [1 to 4]*.

Figure 9.4 RRCR output example: RRCR output R1 activates Relay 5

NOTE The RRCR inputs and outputs are not linked. They are independent of each other.

Configure the RRCR outputs (optional)

Under *Power Set point Output Reference*, define the relay outputs.

Figure 9.5 Example of power set point outputs for RRCR

RRCR Power set point output example

As the figure shows, the power set point output for RRCR is enabled.

If the controller power set point is 30 to 39 %, R1 and R2 are activated.
If the controller power set point is 40 to 49 %, R3 is activated.

On the left, the 16 output combinations are shown (red box). You cannot change these.

RRCR is *Enabled* (*Disabled* by default) using *Power Set point outputs* (blue box).

For each output combination, under *P [%]* (black box), select the power set point.

Under *P Select* (orange box), select *P* for the controller to use *P [%]* as the set point for regulation. If *P Select* is *Off*, the controller does not use that RRCR output combination to output the power set point.

NOTE The curve of P % values must be linear.

9.22 Manual governor and AVR control

The manual governor and AVR control function can be activated by pressing ▽ more than two seconds, or by activating the digital inputs or AOP buttons for governor or AVR control in semi-auto mode. The intention of this function is to give the commissioning engineer a helpful tool for adjustment of the regulation.

When using the display arrows for increasing or decreasing, the output will change as long as the button is active. For the digital input and AOP buttons, there is a timer so that it is possible to choose how long one pulse should be; the timer can be set to 0.1 to 10 sec. For the governor, the timer parameter is 2782 and for AVR, it is 2784. If for example the timer is set to 5 sec., then one push on the AOP or one pulse from digital input will give 5 sec. increase or decrease of the output.

The function of the regulation window depends on the selected mode:

G 0	0	0V
P-Q Setp	100 %	100 %
P-Q Reg.	50 %	60 %
	<u>GOV</u>	AVR

9.22.1 Manual mode

In manual mode the regulation is deactivated. When activating the up or down arrows, the output value to GOV or AVR is changed, this is the Reg. value in the display. The up and down arrows have the same function as the digital inputs or AOP buttons for governor and AVR control when the window is open. To exit the regulation window press "back".

9.22.2 Semi-auto mode

As in manual mode, the up and down arrows have the same function as the digital inputs or AOP buttons for governor or AVR control when the window is open.

The value Setp can be changed by pressing the arrow up or down. When GOV is underlined, the governor set point will be changed, and vice versa when the AVR is underlined. When changing the Setp value, an offset will be added to or subtracted from the nominal value. The Reg. value is the output value from the regulator. If the genset is running in parallel, the active or reactive nominal power set point value will be changed. If it is a stand-alone genset not parallel to the mains, the nominal frequency or voltage set point will be changed and also displayed. When the "back" button is activated, the regulation set point returns to nominal.

NOTE If the digital inputs or AOP buttons are activated in semi-auto, the regulation window is automatically opened.

9.22.3 Auto and test mode

Like semi-auto, except from the fact that activating the digital inputs or AOP buttons for governor or AVR control will change the regulation set point but not open the regulation window. When the digital inputs or AOP buttons are deactivated, the regulation set point returns to nominal.

NOTE For AOP setup, see *Help* in the PC utility software.

9.23 Fail class

All activated alarms must be configured with a fail class. The fail classes define the category of the alarms and the subsequent alarm action.

The tables below show the action of each fail class for a genset controller when the engine is running or stopped.

NOTE All fail classes trigger the alarm *Warning*, which is shown in the active alarm log.

More information
See **Option G5 Power management** for mains and BTB controller fail classes. See **Option G7 Extended power management** for plant and group controller fail classes.

9.23.1 Engine running

Fail class	Action	Alarm horn relay	Alarm display	De-load	Trip of gen. breaker	Trip of mains breaker	Cooling-down genset	Stop genset
1 Block		●	●					
2 Warning		●	●					
3 Trip GB		●	●		●			
4 Trip + stop		●	●		●		●	●
5 Shutdown		●	●		●			●
6 Trip MB		●	●			●		
7 Safety stop*		●	●	●**	●		●	●
8 Trip MB/GB		●	●		●**	●		
9 Controlled stop*		●	●	●	●		●	●

*Note: *Safety stop* and *Controlled stop* are shown as identical, but they act differently: *Safety stop* de-loads and stops the genset if other power sources are able to take the load; if not, the genset does not stop. *Controlled stop* de-loads the genset, but if no other power sources are available to take the load, the genset trips the breaker and stops. This means that *Controlled stop* prioritises protection of the genset, whereas *Safety stop* prioritises the load.

**Note: *Safety stop* only de-loads the genset before opening the breaker if option G5 (power management) is used. If power management is not active, *Safety stop* is similar to *Controlled stop*.

***Note: *Trip MB/GB* only trips the generator breaker if there is no mains breaker present.

The table shows the action of the fail classes. If, for example, an alarm has been configured with the *Shutdown* fail class, the following actions occur.

- The alarm horn relay activates
- The alarm is displayed in the alarm info screen
- The generator breaker opens instantly
- The genset is stopped instantly
- The genset cannot be started from the controller (see next table)

9.23.2 Engine stopped

Fail class	Action	Block engine start	Block MB sequence	Block GB sequence
1 Block		●		
2 Warning				
3 Trip GB		●		●
4 Trip + stop		●		●
5 Shutdown		●		●
6 Trip MB			●	
7 Safety stop		●		
8 Trip MB/GB		●*	●	●*
9 Controlled stop		●		●

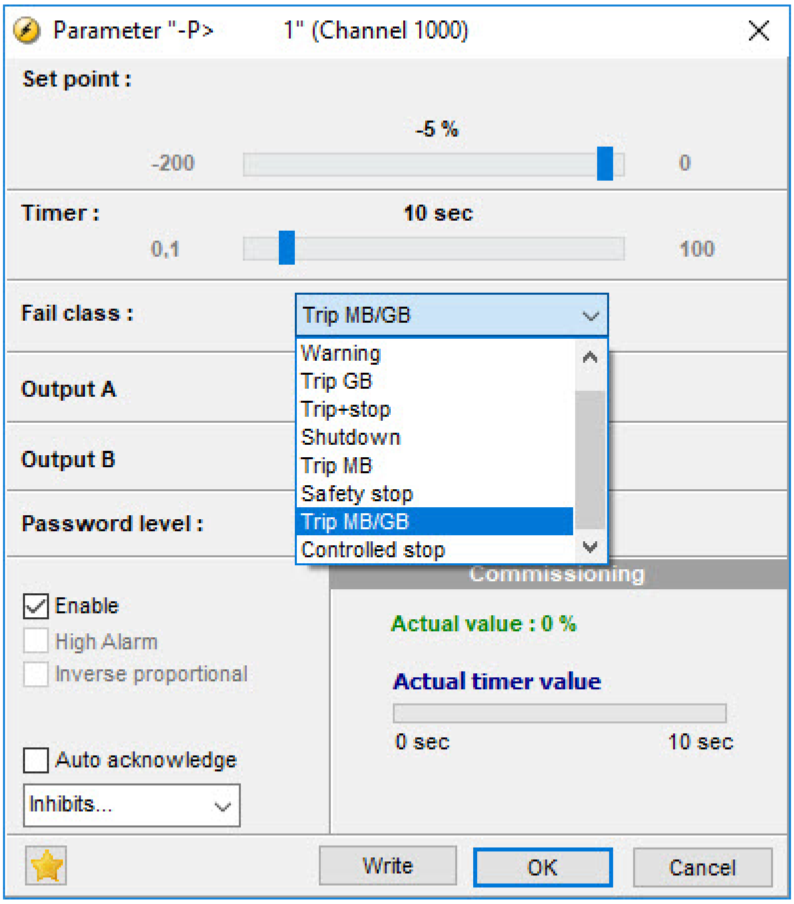
*Note: The fail class *Trip MB/GB* only blocks engine start and GB sequence if there is no mains breaker present.

NOTE In addition to the actions defined by the fail classes, it is possible to activate one or two relay outputs if additional relays are available in the controller.

9.23.3 Fail class configuration

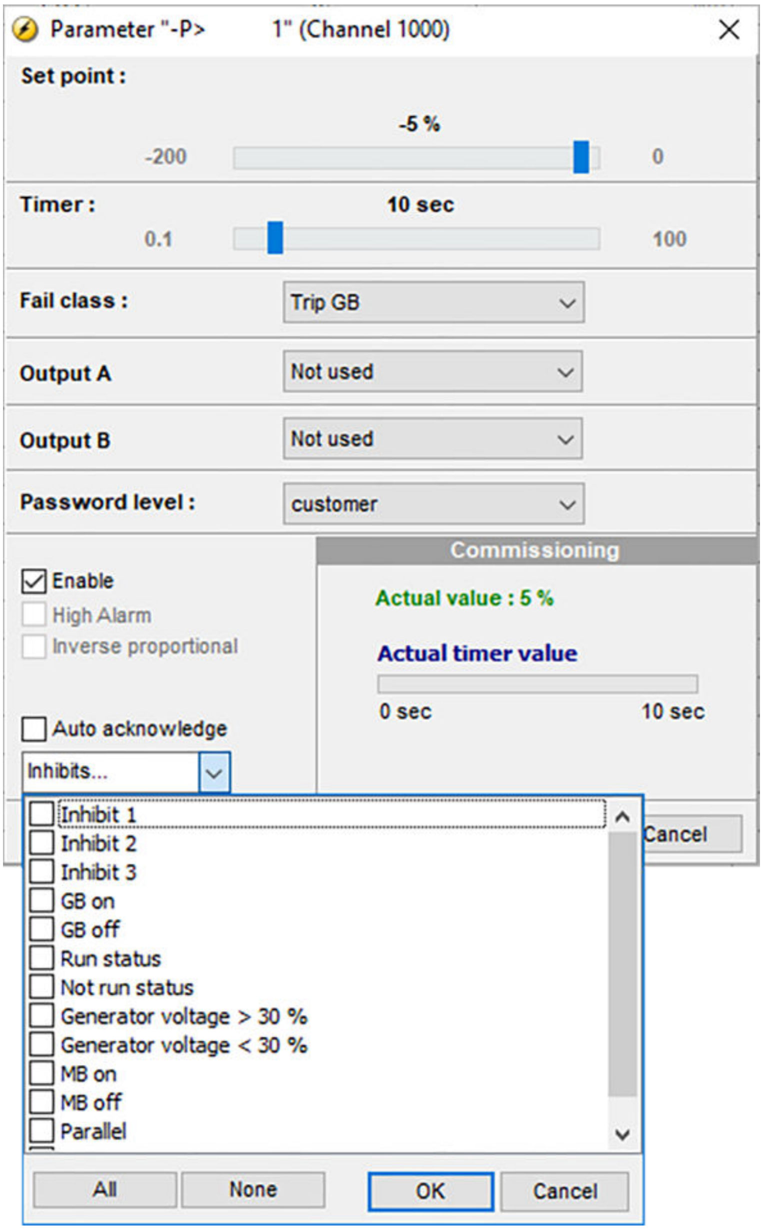
The fail class can be selected for each alarm function either via the display or the PC software.

To change the fail class via the PC software, the alarm function to be configured must be selected. Select the desired fail class in the fail class roll-down panel.



9.24 Alarm inhibit

In order to select when the alarms are to be active, a configurable inhibit setting for each alarm has been made. The inhibit functionality is only available via the PC utility software. For each alarm, there is a drop-down window where it is possible to select which signals that have to be present in order to inhibit the alarm.



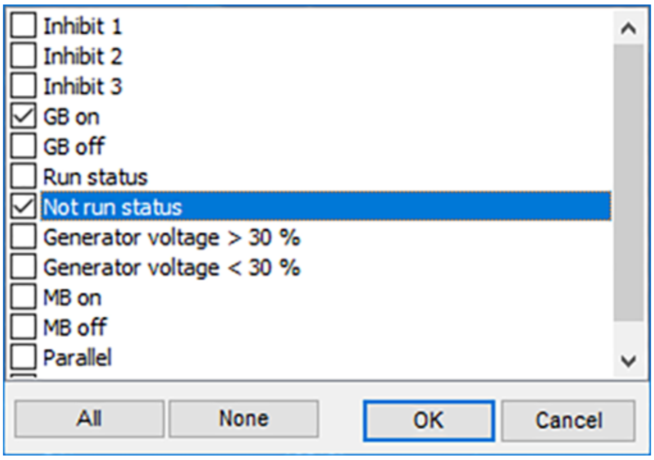
Selections for alarm inhibit:

Function	Description
Inhibit 1	
Inhibit 2	M-Logic outputs: Conditions are programmed in M-Logic
Inhibit 3	
GB on (TB on)	The generator breaker is closed
GB off (TB off)	The generator breaker is open
Run status	Running detected and the timer in menu 6160 expired
Not run status	Running not detected or the timer in menu 6160 not expired

Function	Description
Generator voltage > 30%	Generator voltage is above 30% of nominal
Generator voltage < 30%	Generator voltage is below 30% of nominal
MB on	The mains breaker is closed
MB off	The mains breaker is open
Parallel	Both GB and MB are closed
Not parallel	Either GB or MB is closed, but not both
Redundant controller	The controller is the redundant controller (only shown if option T1 is activated)

NOTE The timer in 6160 is not used if binary running feedback is used.

Inhibit of the alarm is active as long as one of the selected inhibit functions is active.



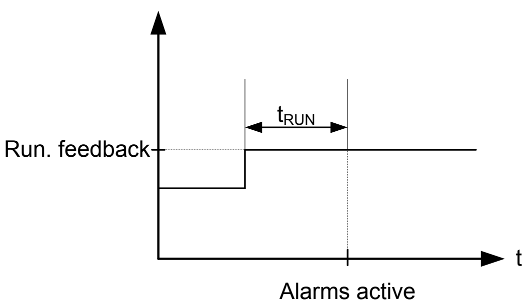
In this example, inhibit is set to *Not run status* and *GB ON*. Here, the alarm will be active when the generator has started. When the generator has been synchronised to the busbar, the alarm will be disabled again.

NOTE The inhibit LED on the controller and on the display will activate when one of the inhibit functions is active.
NOTE Function inputs such as running feedback, remote start or access lock are never inhibited. Only alarm inputs can be inhibited.
NOTE The BTB controller has no running detection that can be configured, so the only inhibit functions are the binary input and the TB position.

9.24.1 Run status (6160)

Alarms can be adjusted to activate only when the running feedback is active and a specific time delay has expired.

The diagram below illustrates that after activation of the running feedback, a run status delay will expire. When the delay expires, alarms with *Run status* will be activated.



NOTE The timer is ignored if digital running feedback is used.

9.25 Event log

9.25.1 Logs

The logging of data is divided in three different groups:

- Event log containing 500 entries.
- Alarm log containing 500 entries.
- Battery test log containing 52 entries.

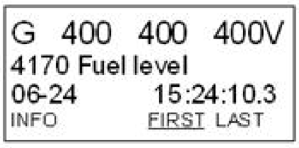
The logs can be viewed in the display or in the PC utility software. When the individual logs are full, each new event will overwrite the oldest event, using the "first in - first out" principle.

9.25.2 Display

In the display it looks like this when the "LOG" push-button is pressed:

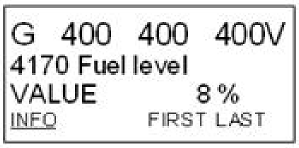
Now it is possible to select one of the three logs.

If the "Event" is selected, the log could look like this:



The specific alarm or event is shown in the second line. In the example above the fuel level alarm has occurred. The third line shows the time stamp.

If the cursor is moved to "INFO", the actual value can be read when pressing "SEL":



The first event in the list will be displayed if the cursor is placed below "FIRST" and "SEL" is pressed.

The last event in the list will be displayed if the cursor is placed below "LAST" and "SEL" is pressed.

The keyUP and keyDOWN push-buttons are used for navigating in the list.

9.26 Connection TCP/IP and network parameters

You can use TCP/IP communication to connect to the controller. This requires an Ethernet cable, or a connection to the network that includes the controller.

Default controller network address

- IP: 192.168.2.21
- Gateway: 192.168.2.1
- Subnet mask: 255.255.255.0

Configuring the controller IP address using the display unit or a USB connection

When connecting to a controller using TCP/IP, you must know the controller's IP address. Find the IP address on the display under jump menu 9002.

You can use a USB connection or an Ethernet connection, and the utility software to change the controller IP address.

How to use a USB cable to AGC-4
See our tutorial on How to use USB cable to AGC-4 for help and guidance.

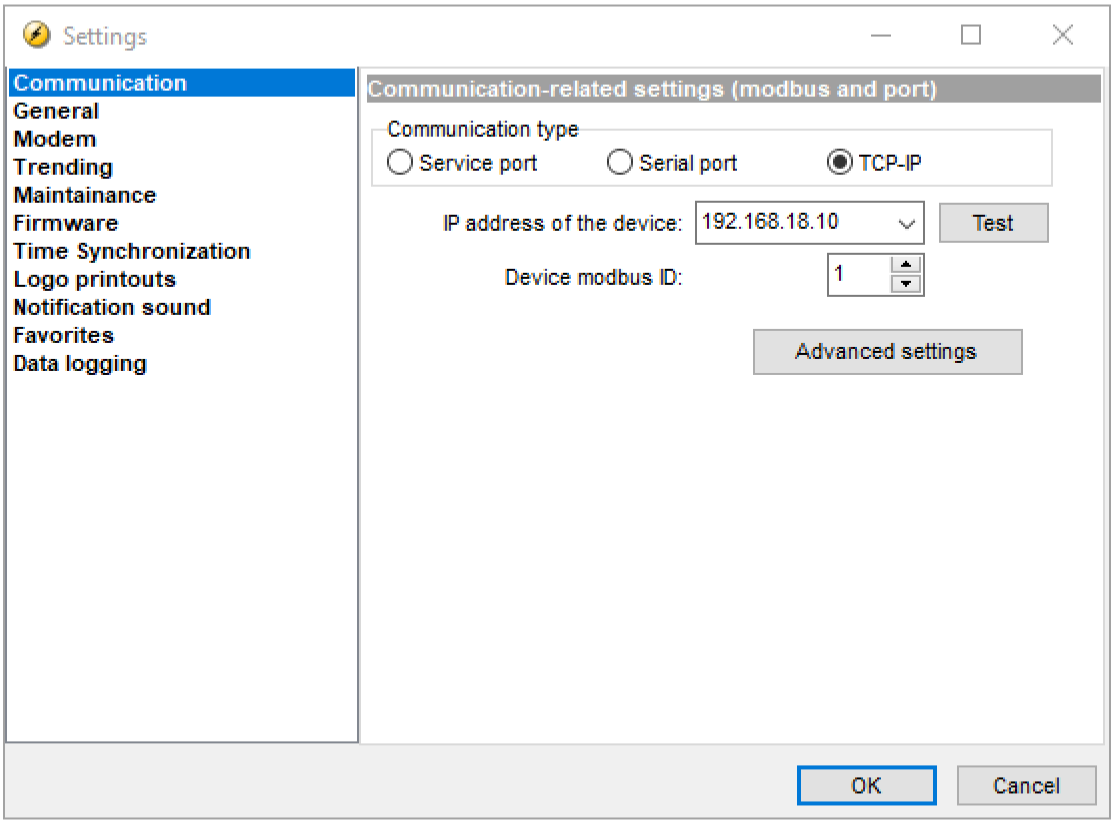
Point-to-point Ethernet connection to the controller

If you do not want to use a USB connection to change the IP address, you can use a point-to-point Ethernet connection. The PC must have a static IP address. For the default controller network address, the PC static IP address must be 192.168.2.xxx, where xxx is a free IP-address in the network.

If you change the controller address (for example, from 192.168.**2**.yyy to 192.168.**47**.yyy) the connection is lost. A new static IP for the PC is needed. In this case, 192.168.47.zzz, where zzz is a free IP-address in the network.

When the PC has the correct static IP address:

1. Use an Ethernet cable to connect the PC to the controller.
2. Start the utility software.
3. Select *TCP-IP*, and enter the controller IP address.

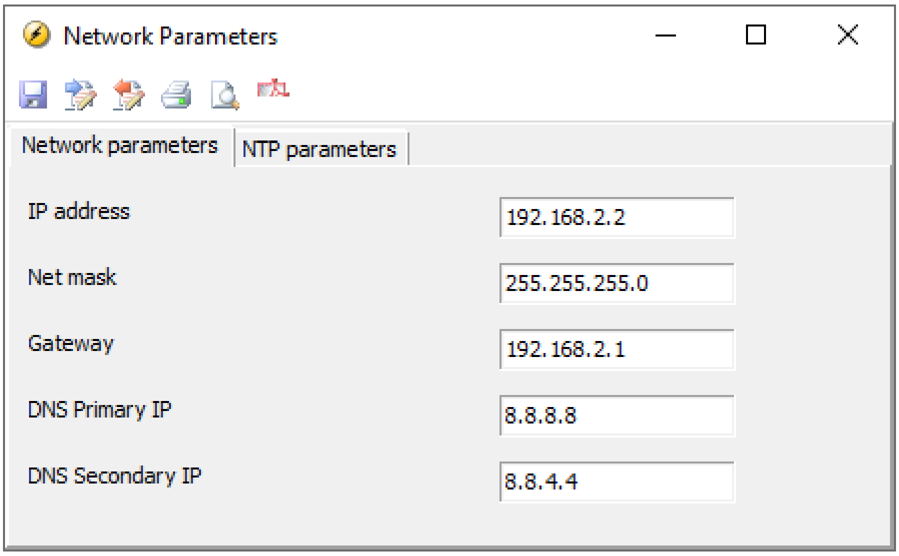


4. You can use the *Test* button to check if the connection is successful.
5. Select *Connect* to connect to the controller using TCP-IP.

How to use an Ethernet cable to AGC-4
See our tutorial on How to use Ethernet cable to AGC-4 for help and guidance.

Configuring the controller IP address using the utility software

To change the controller network parameters from the utility software, press the *Option N configuration* button. The *Network Parameters* window opens:



When the controller network parameters have been changed, press the *Write to device* button.

The controller receives the new network parameters and reboots the network hardware.

To connect to the controller again, use the new controller IP address (and a correct PC static IP address).

Using a switch

For a system with multiple controllers, all controllers can be connected to a switch. Create a unique IP address for each controller in the network before connecting the controllers to a switch.

The PC can then be connected to the switch, and the Ethernet cable can be in the same port of the switch at all times. You can enter the controller IP address in the utility software.

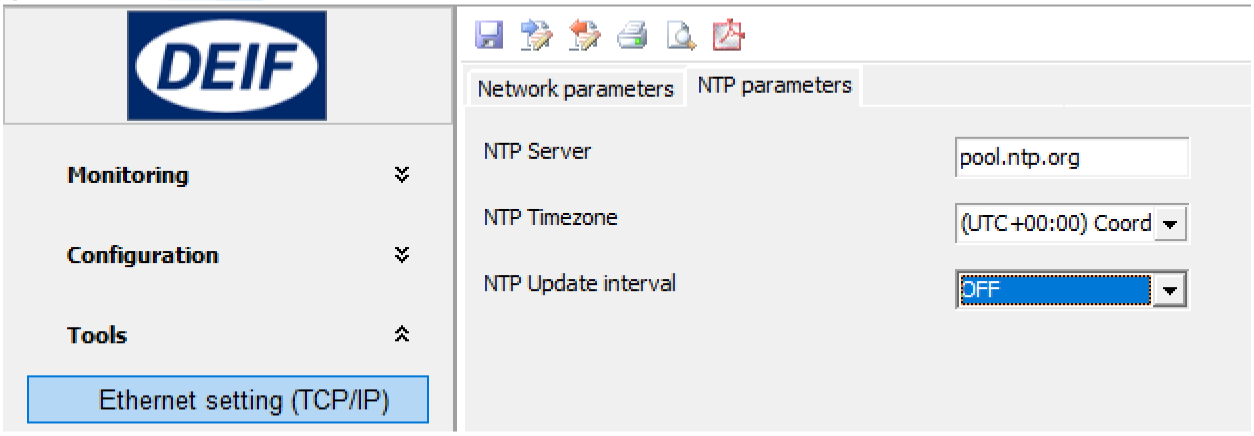
The TCP-IP connection is faster than other connections. It also allows the user to shift between controllers in the application supervision window in the utility software.

How to configure an IP address on AGC-4
See our tutorial on How to configure IP address on AGC-4 for help and guidance.

9.26.1 Using NTP

To ensure that the controller always has the right time, you can use the network time protocol (NTP) function.

Select *Ethernet setting (TCP/IP)* in the Utility software, then select the *NTP parameters* tab in the *Network Parameters* window:



You can select an NTP server, a time zone and an update interval. Write the changes to the controller to activate the NTP function.

9.27 M-Logic

How to create M-Logic on AGC-4
See our tutorial on How to create M-Logic on AGC-4 for help and guidance.

M-Logic is a simple tool based on logic events. One or more input conditions are defined, and at the activation of those inputs, the defined output will occur. A variety of inputs can be selected, such as digital inputs, alarm conditions and running conditions. A variety of outputs can also be selected, such as relay outputs and change of controller modes.

M-Logic is included in the controller by default. It does not require any options. However, selecting additional options (for example, option M12, which offers additional digital inputs and outputs) can increase the functionality.

M-Logic is not a PLC, but can function as a PLC if only very simple commands are needed.

NOTE M-Logic is part of the PC utility software. It can only be configured using the PC utility software (and not via the display).

More information
See the **Application notes M-Logic** for an overview of the M-Logic function. You can also refer to the *Help* function in the PC utility software.

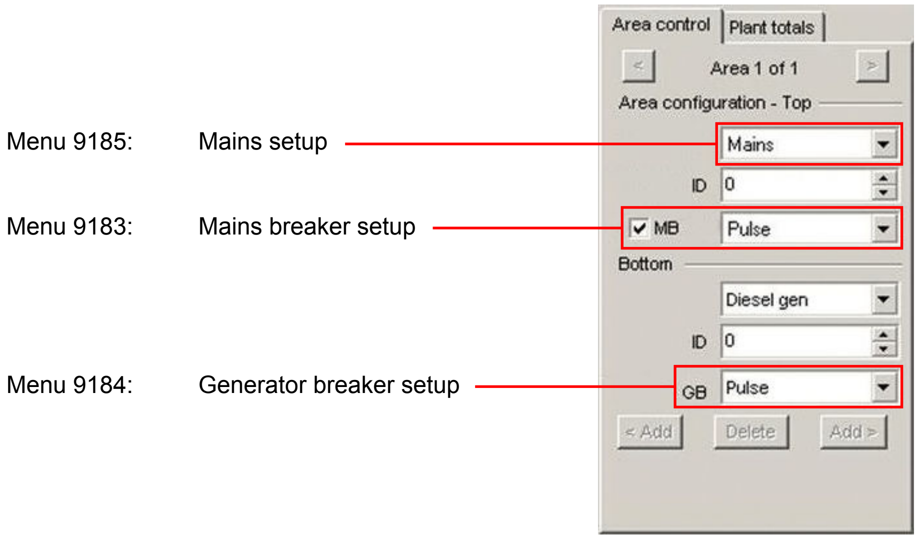
9.28 Quick setup

Both the PC utility software and the quick setup menu can be used to set up a plant.

The quick setup menu is made to provide easy setup of a plant. Entering the quick setup menu 9180 via the DU-2 display gives the possibility to add or remove e.g. mains and MB without using the utility software. It is only possible to do the same basic setup as via the application configuration in the utility software.

Menu 9180 Quick setup

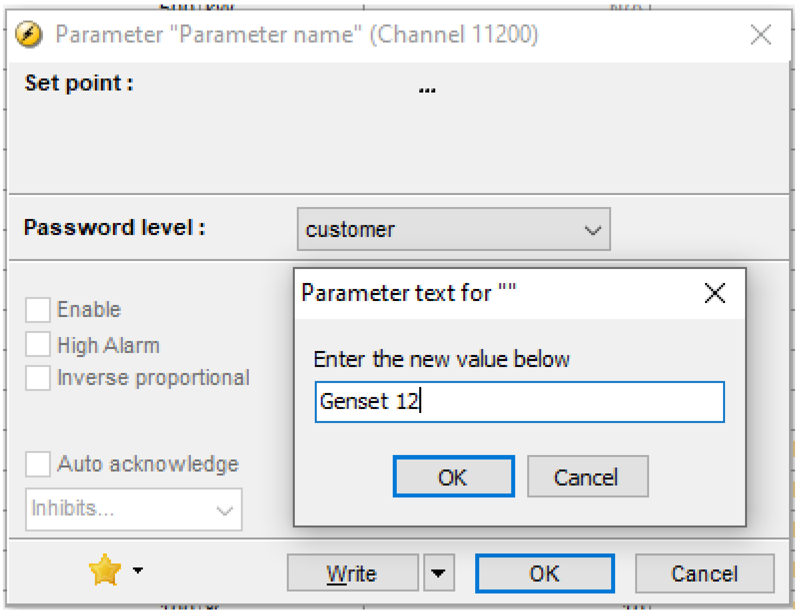
- 9181: Mode
- OFF: When the mode menu is set to **OFF**, the existing application of the genset will not be changed.
- Setup plant: The setup plant mode is used in G5 applications. For more information, refer to the option G5 manual.
- Setup stand-alone: When the mode menu is set to *Setup stand-alone*, the AGC will change the application configuration. The settings in menu 9182-9185 are used for the new configuration.



NOTE If *Setup stand-alone* is activated while the genset is running, an info text, *Quick setup error*, will appear.

9.29 Parameter ID

You can add a short text name in parameter 11200 to identify the parameter file used in the controller.



9.30 Language selection

The controller can display different languages. It is delivered with one master language, which is English. This is the default language, and it cannot be changed. In addition to the master language 11 different languages can be configured. This is done via the PC utility software.

The languages are selected in the system setup **menu 6080**. The language can be changed when connected to the PC utility software. It is not possible to make language configuration from the display, but the already configured languages can be selected.

9.31 Master clock

The purpose of the master clock is to control the frequency of the genset in order to obtain the correct number of periods.

NOTE This function can only be used if island operation is selected.

In a 50 Hz system one period lasts 20 ms. If this changes, for example, due to the dead band setting of the frequency controller, a difference will exist between the actual number of periods and the theoretical number of periods.

Equipment that works based on the zero crossings will be affected by the surplus or missing zero crossings. The most common example of such equipment is alarm clocks.

The controller's internal clock is a timekeeper which is included in the battery backed memory circuit. The timekeeper function works based on an oscillating crystal instead of zero crossings of the AC measurements. Due to the accuracy of the timekeeper, it is recommended to synchronise the clock regularly, for example, once a month.

Parameter	Name	Description	Comment
6401	Start	Start time.	The compensation period starts at the adjusted time.
6402	Stop	Stop time.	The compensation period stops at the adjusted time.
6403	Difference	The set point in seconds that initiates the compensation.	
6404	Compensation	Frequency difference when the compensation is initiated.	+/- value.
6405	Enable	Enables the function.	

NOTE The compensation frequency must be adjusted to a value higher than the dead band setting.

9.31.1 Compensation time

The time for the compensation can easily be calculated at a given adjustment of 6403 and 6404 (example):

- 6403 = 30 seconds
- 6404 = +/- 0.1 Hz

t(total) = t(set) / (1 - f(nom) / f(diff))
t(total) = 30 s / (1 - 50 Hz / 50.1 Hz)
t(total) = 15030 s ≅ 4.1 hours

9.32 Summer/winter time

This function makes the controller automatically adjust its clock for summer and winter time. The function is enabled in menu 6490.

NOTE The function only supports the Danish rules.

9.33 Access lock

The purpose of access lock is to deny the operator the possibility to configure the controller parameters and change the controller modes. The input to be used for the access lock function is defined in the utility software (USW).

Access lock will typically be activated from a key switch installed behind the door of the switchboard cabinet. As soon as access lock is activated, changes from the display cannot be made.

Access lock will only lock the display and will not lock any AOP or digital input. AOP can be locked by using M-Logic. It will still be possible to read all parameters, timers and the state of inputs in the service menu (9120).

It is possible to read alarms, but not any alarms when access lock is activated. Nothing can be changed from the display.

This function is ideal for a rental generator, or a generator placed in a critical power segment. The operator does not have the possibility to change anything. If there is an AOP-2, the operator will still be able to change up to 8 different predefined things.

NOTE The stop push-button is not active in semi-auto mode when the access lock is activated. For safety reasons it is recommended to install an emergency stop switch.

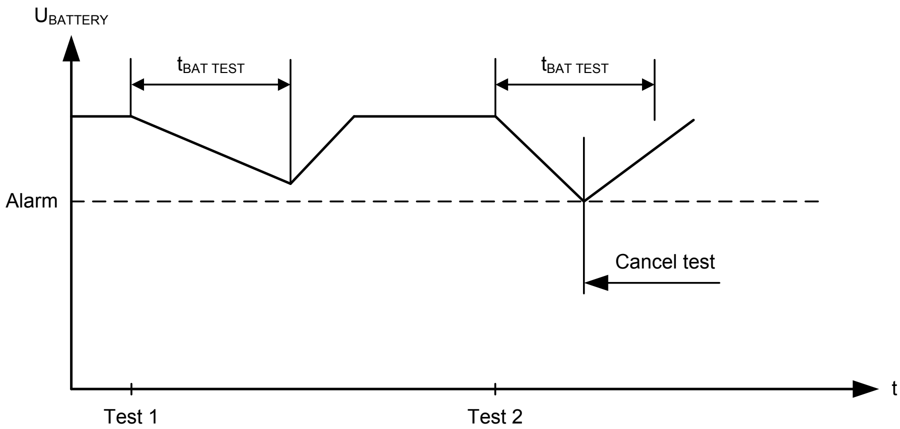
NOTE AOP buttons are not locked when access lock is activated.

9.34 Battery test

This function gives the possibility to test the condition of the battery. The battery test can be initiated with a digital input and is available when the genset is in semi-auto and auto mode.

If a mains failure occurs during the battery test sequence, the test will automatically be interrupted, and the automatic mains failure start up sequence will be activated.

During the test, the battery voltage will decrease and an alarm will occur if it drops to the set point that has been configured in *Battery test* (parameter 6411).



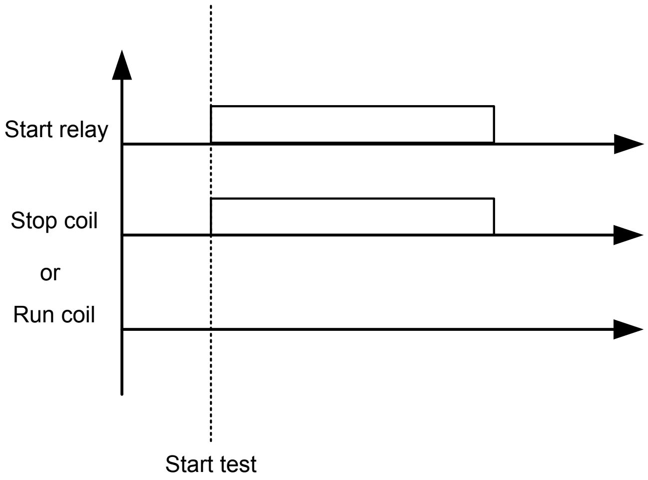
The drawing shows that test #1 is carried out without a large voltage drop of the battery voltage, whereas test #2 reaches the alarm set point. As there is no reason to wear the battery down even more, the test stops when the battery test alarm occurs.

The test is typically used at periodical intervals, for example, once every week. The engine must be at a standstill when the test is started. Otherwise, the test command will be ignored.

The stop relay will act depending on the coil type:

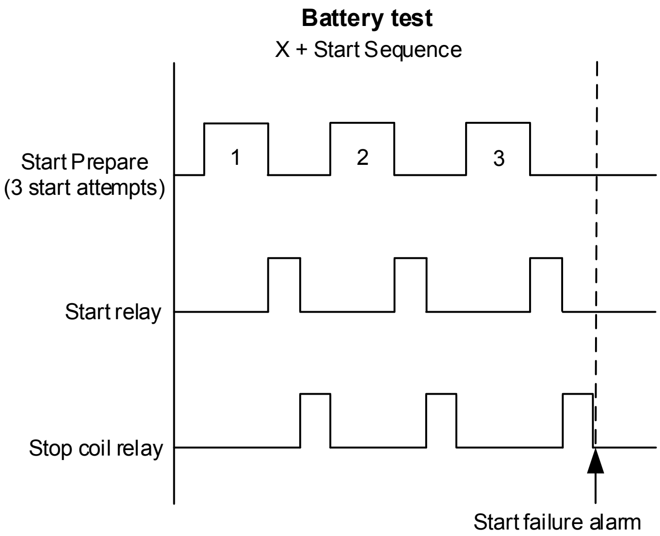
- Stop coil: The stop relay activates during the test.
- Run coil: The stop relay stays deactivated during the test.

The drawing below shows that when the test is started, the start relay activates, making the engine turn. The engine will turn in the time period that has been configured in *Battery test* (parameter 6412).



Battery test “X + Start sequence”

If the set point in *Battery test* (parameter 6413) has been configured to *X + Start sequence*, the genset will run the defined start attempts (without activating run coil). This function is used to test that the battery can withstand more than one start attempt.



A battery test configured as *X + Start sequence*, as shown in the above example, will use: *Start prepare* timer, *Start on time* and *Start off time*. In this example, the genset will crank three times with *Start prepare* and *Start off time* delay in between each crank. When the test has finished, a start failure alarm will be present.

If at any point the battery voltage is lower than the set point *Battery test* (parameter 6411), the test will be cancelled.

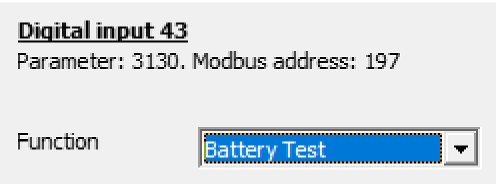
Description	Comments
Battery test (parameter 6411)	Minimum voltage level
Battery test (parameter 6413)	Set point: X + Start sequence
Battery test (parameter 6415)	Enable/disable
Battery test (parameter 6416)	Fail class
Start Prepare (parameter 6181)	Timer before crank
Start on Time (parameter 6183)	Start relay ON timer

Description	Comments
Start off Time (parameter 6184)	Stop coil relay ON timer
Start attempts (parameter 6190)	Number of start attempts

NOTE For normal operation, the start failure alarm must be acknowledged after the test has ended.

9.34.1 Input configuration

If this function is to be used, it is necessary to configure a digital input that initiates the function. This is done in the dialogue box below.



NOTE If AUTO mode is selected, the mains failure sequence will be initiated if a mains failure occurs during the battery test.

9.34.2 Auto configuration

If the automatic battery test is used, the function must be enabled in menu 6420. When the function is enabled, the battery test will be carried out with a specified interval, for example, once a week. Completed battery tests will be logged in a separate battery test log.

NOTE The factory setting in menu 6424 is 52 weeks. This means that the automatic battery test will be executed once a year.

NOTE If *Battery test* (parameter 6413) is configured to *X + Start sequence*, the alarm *Start failure* (parameter 4570) will occur at the end. If the alarm is left unacknowledged, the genset will not be operational.

9.34.3 Battery asymmetry (6430 Batt. asymmetry)

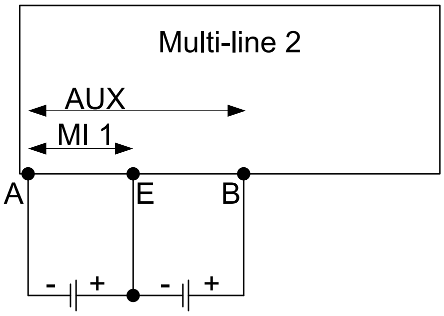
The reason for making the battery asymmetry test is to determine if one of the batteries is getting weak. The battery asymmetry is a combination of measurements and calculations.

Set points available:

- T1: The input type to be used for calculation of battery asymmetry.
- RF1: Reference of asymmetry measurement no. 1.
- T2: The input type to be used for calculation of battery asymmetry 2.
- RF2: Reference of asymmetry measurement no. 2.

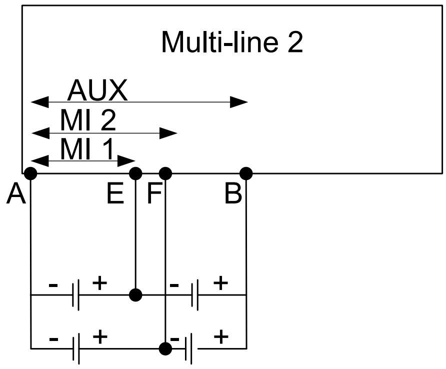
The following seven battery applications are supported. The shown applications are merely examples – the choice of multi-input (MI) or power supply input is configurable in menu 6410.

Application 1:



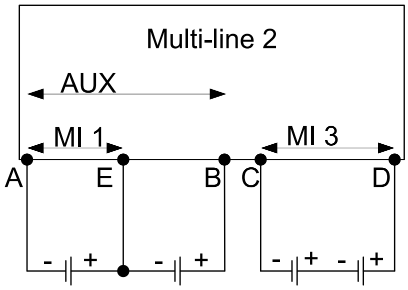
Start/Manoeuvre battery

Application 2:



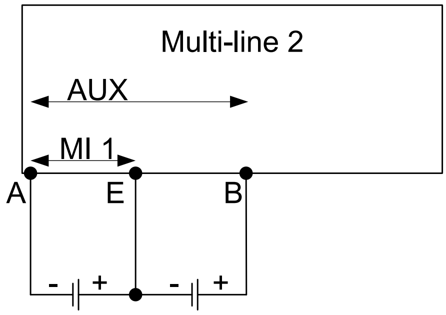
Start/Manoeuvre battery

Application 3:



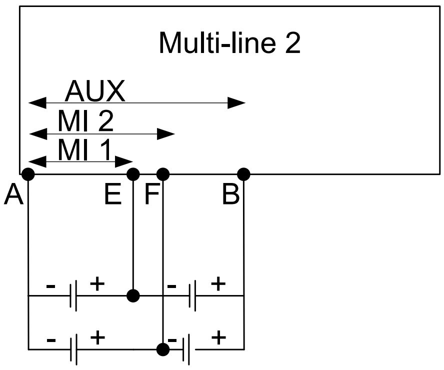
Manoeuvre battery Start battery

Application 4:

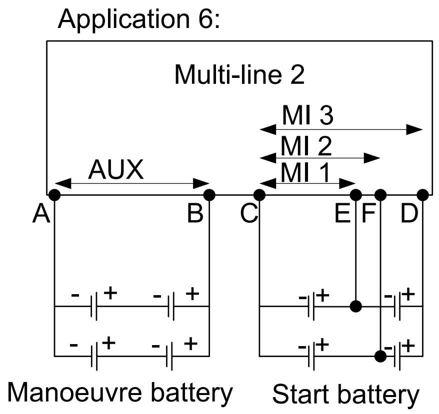


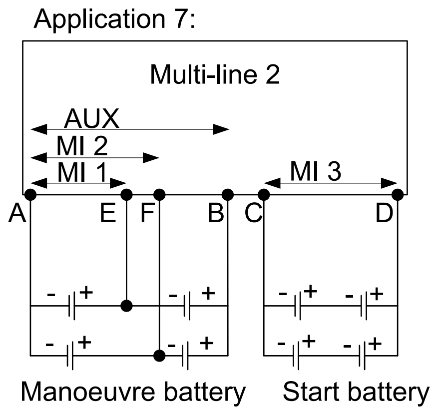
Manoeuvre battery

Application 5:

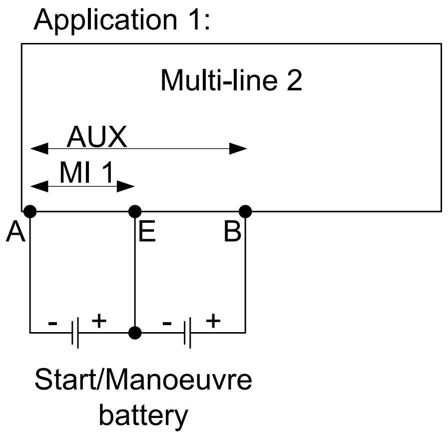


Manoeuvre battery





Looking at battery application 1 as an example:



The power supply measurement is used as the reference RF1 (points A and B) in menu 6432 and multi-input 1 is used as the type T1 (points A and E) in menu 6431. By making these measurements, it is possible to calculate the voltage between E and B. This gives a full picture of battery voltages, for example:

- Measured value A/B (RF1) = 21 V DC
- Measured value A/E (T1) = 12 V DC
- Calculated value E/B (RF1 – T1) = 9 V DC
- Battery asymmetry = E/B – (RF1*1/2) = 9 – (21*1/2) = -1.5 V DC

NOTE If application 3, 6 or 7 is used, it is expected that one of the multi-inputs is used for the battery test of the starter battery.

NOTE It is expected that the multi-inputs used for the battery asymmetry are configured to *0 to 40 V DC*.

NOTE The selection power supply is referring to the supply on terminals 1 and 2.

Battery asymmetry alarm

Alarms for battery asymmetry 1 and 2 are set up in menus 6440 and 6450.

NOTE The set point in menus 6440 and 6450 is positive. However, the alarm is also activated if the battery asymmetry calculation is negative.

9.35 Switchboard error

The switchboard error function is handled in two different menus: 6500 "Block swbd error" and 6510 "Stop Swbd error". The functions are activated by using one configurable input (switchboard error) which is configured with the PC utility software.

NOTE The functionality of the “switchboard error” input is active as soon as the input is configured. The “enable” in menus 6500 and 6510 only refers to the alarm function.

9.35.1 Block swbd error (menu 6500)

When activated, this function will block the start sequence of the genset in case the genset is not running.

Set points available:

- Delay: When the input is active, the alarm will be activated when this delay has expired.
- Parallel:
  - OFF: Only AMF start sequence is blocked when the input is active.
  - ON: All start sequences, regardless of running mode, are blocked when the input is active.
- Output A: Relay to activate when the delay has expired.
- Output B: Relay to activate when the delay has expired.
- Enable: Enable/disable the alarm function.
- Fail class: The fail class of the alarm.

9.35.2 Stop swbd error (menu 6510)

When activated, this function will stop the genset if the genset is running in Auto mode.

Set points available:

- Delay: When the input is active and the delay has expired, the genset will trip the breaker, cool down and stop. The function is active regardless of the "Enable" setting.
- Output A: Relay to activate when the delay has expired.
- Output B: Relay to activate when the delay has expired.
- Enable: Enable/disable the alarm function.
- Fail class: The fail class of the alarm.

9.36 Step-up and step-down transformer

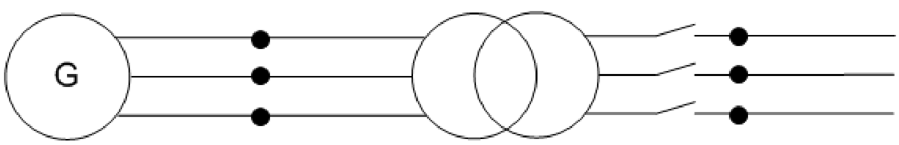
9.36.1 Step-up transformer

In certain cases, the use of a generator with step-up transformer (called a block) is required. This may be to adapt to the closest grid voltage or to step up the voltage to minimise the losses in cables and also to bring down the cable size. The applications where a step-up transformer is needed, is supported by the ML-2. The functions available in this application are:

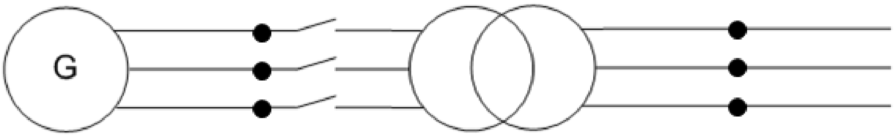
1. Synchronising with or without phase angle compensation
2. Voltage measurement displayed
3. Generator protections
4. Busbar protections

A diagram of a block is shown below

Generator/transformer block:



Typically the synchronising breaker is on the high voltage (HV) side, and there is no breaker (or only a manually operated one) on the low voltage (LV) side. In some applications, the breaker could also be placed on the LV side. But this does not influence on the setting in the ML-2, as long as the breaker and the step-up transformer are both placed between the generator and busbar, and mains voltage measuring points for the ML-2. The measuring points are shown as black dots in the figures above and below.



The phase angle compensation would not be an issue if there was no phase angle shift across the step-up transformer, but in many cases there is. In Europe, the phase angle shift is described using the vector group description. Instead of vector group, this could also be called clock notation or phase shift.

NOTE When voltage measurement transformers are used, these must be included in the total phase angle compensation.

When an ML-2 is used for synchronising, the device uses the ratio of the nominal voltages for the generator and the busbar, to calculate a set point for the AVR and the voltage synchronising window (dU_{MAX}).

Example

A 10000 V/400 V step-up transformer is installed after a generator with the nominal voltage of 400 V. The nominal voltage of the busbar is 10000 V. Now, the voltage of the busbar is 10500 V. The generator is running 400 V before synchronising starts, but when attempting to synchronise, the AVR set point will be changed to:

$U_{BUS\text{-}MEASURED} \times U_{GEN\text{-}NOM}/U_{BUS\text{-}NOM}$ = 10500 × 400/10000 = **420 V**

9.36.2 Vector group for step-up transformer

Vector group definition

The vector group is defined by two letters and a number:

- The first letter is an upper case D or Y, defining if the HV side windings are in delta or wye configuration.
- The second letter is a lower case d, y or z, defining if the LV side windings are in delta, wye or zigzag configuration.
- The number is the vector group number, defining the phase angle shift between HV and LV side of the step-up transformer. The number is an expression of the LV side lag compared to the HV side voltage. The number is an expression of the lag angle divided by 30 degrees.

Example

Dy11 = HV side: Delta, LV side: Wye, vector group 11: Phase shift = 11 × (–30) = -330 degrees.

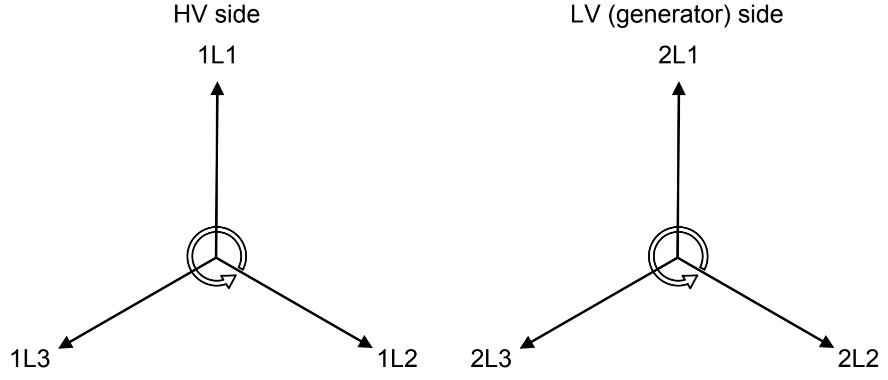
Typical vector groups

Vector group	Clock notation	Phase shift	LV lag degrees compared to HV
0	0	0 °	0 °
1	1	-30 °	30 °
2	2	-60 °	60 °
4	4	-120 °	120 °
5	5	-150 °	150 °
6	6	-180 °/180 °	180 °
7	7	150 °	210 °
8	8	120 °	240 °
10	10	60 °	300 °
11	11	30 °	330 °

Vector group 0

The phase shift is 0 degrees.

Figure 9.6 Yy0 example



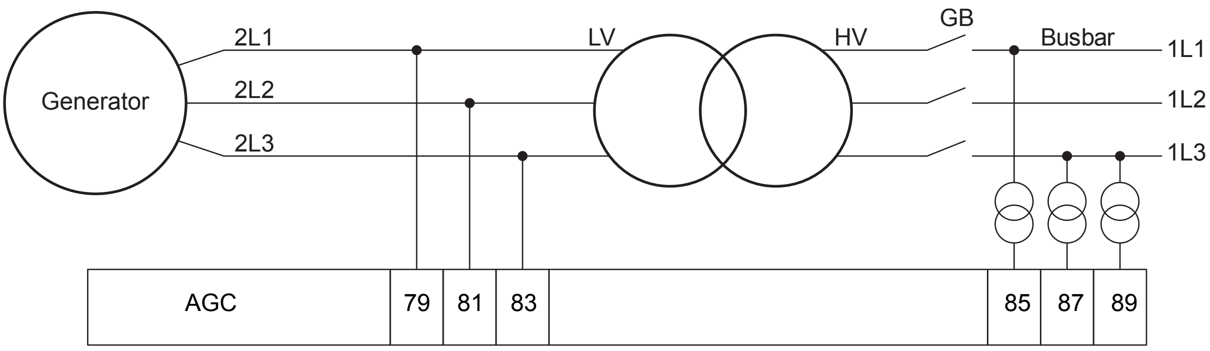
1L1 to 2L1 phase angle is 0 degrees

Table 9.1 Phase compensation setting

Parameter	Function	Setting
9141*	BB (mains)/generator angle compensation	0 degrees

NOTE * This parameter is for busbar parameter set 1. Use parameter 9142 for busbar parameter set 2.

Figure 9.7 Connections

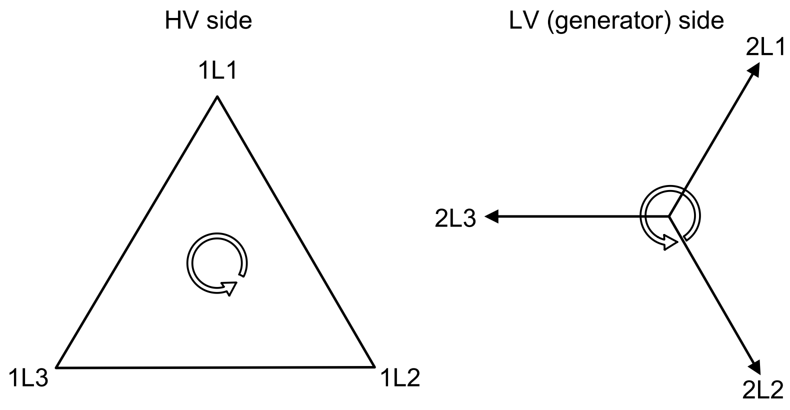


NOTE The connection shown in the diagram should always be used when an AGC is used for a genset.

Vector group 1

The phase shift is -30 degrees.

Figure 9.8 Dy1 example



1L1 to 2L1 phase angle is -30 degrees.

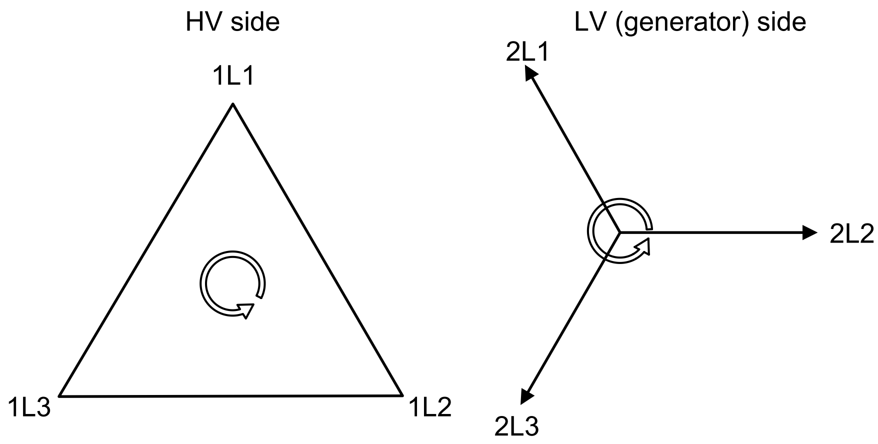
Table 9.2 Phase compensation setting

Parameter	Function	Setting
9141	BB (mains)/generator angle compensation	30 degrees

Vector group 11

The phase angle shift is 11 × (-30) = -330/+30 degrees.

Figure 9.9 Dy11 example



1L1 to 2L1 phase angle is -333/+30 degrees.

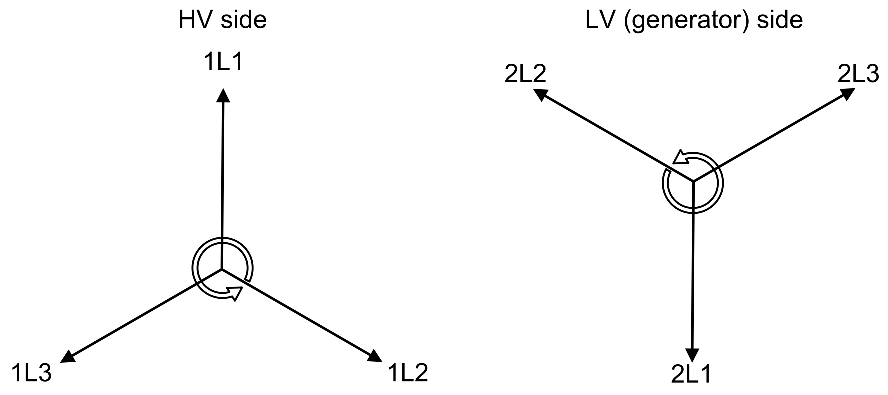
Table 9.3 Phase compensation setting

Parameter	Function	Setting
9141	BB (mains)/generator angle compensation	-30 degrees

Vector group 6

The phase angle shift is 6 × 30 = 180 degrees.

Figure 9.10 Yy6 example



1L1 to 2L1 phase angle is -180/+180 degrees.

Table 9.4 Phase compensation setting

Parameter	Function	Setting
9141	BB (mains)/generator angle compensation	180 degrees

NOTE Select 179 degrees in parameter 9141 when vector group 6 is used.

Table 9.5 Comparison table between different terminologies

Vector group	Clock notation	Phase shift	LV lag degrees compared to HV	LV side lagging	LV side leading
0	0	0 °	0 °	0 °	
1	1	-30 °	30 °	30 °	
2	2	-60 °	60 °	60 °	
4	4	-120 °	120 °	120 °	
5	5	-150 °	150 °	150 °	
6	6	-180 °/180 °	180 °	180 °	180 °
7	7	150 °	210 °		150 °
8	8	120 °	240 °		120 °
10	10	60 °	300 °		60 °
11	11	30 °	330 °		30 °

In the following, the name vector group will be used.

Table 9.6 Table to read parameter 9141 compared to a step-up transformer

Vector group	Step-up transformer types	Parameter 9141
0	Yy0, Dd0, Dz0	0 °
1	Yd1, Dy1, Yz1	30 °
2	Dd2, Dz2	60 °
4	Dd4, Dz4	120 °
5	Yd5, Dy5, Yz5	150 °

Vector group	Step-up transformer types	Parameter 9141
6	Yy6, Dd6, Dz6	180 °
7	Yd7, Dy7, Yz7	-150 °
8	Dd8, Dz8	-120 °
10	Dd10, Dz10	-60 °
11	Yd11, Dy11, Yz11	-30 °

NOTE DEIF does not take responsibility that the compensation is correct. Before closing the breaker, DEIF recommends that customers always measure the synchronisation themselves.

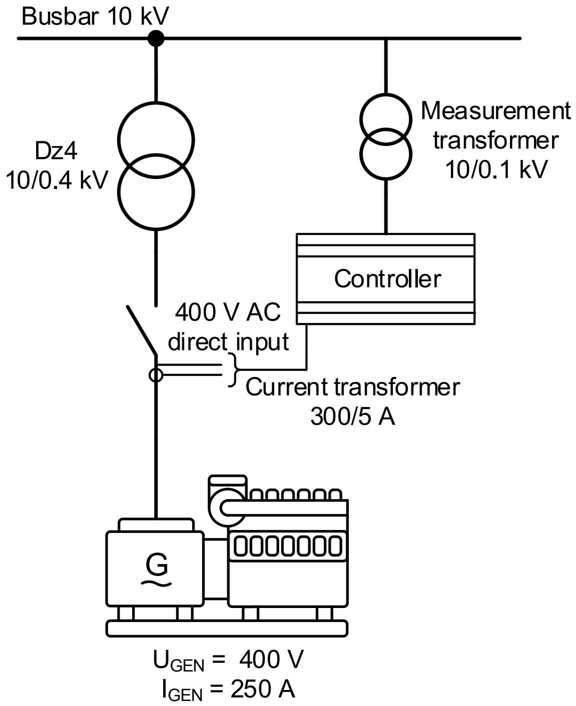
NOTE If voltage measurement is connected incorrectly, the setting in parameter 9141 will be wrong.

NOTE The setting shown in the table above does not include any phase angle twist made by measurement transformers.

NOTE The settings shown in the table above are not correct if a step-down transformer is used. These settings are shown later.

9.36.3 Setup of step-up transformer and measurement transformer

If the HV side of the transformer is transforming the voltage up to a voltage level higher than 690 V AC, it will be necessary with measurement transformers. The setup of all these parameters can be done from the utility software, and will be explained by an example:



- The transformer is a Dz4 step-up transformer, with nominal settings of 10/0.4 kV.
- The generator has a nominal voltage of 0.4 kV, nominal current of 250 A, and a nominal power of 140 kW.
- The measurement transformer has a nominal voltage of 10/0.1 kV, and no phase angle twist.
- The nominal voltage of the busbar (BB) is 10 kV.

Because the generator’s nominal voltage is 400 V, there is no need for a measurement transformer on the LV side in this example. The ML-2 can handle up to 690 V. But it is still required to set up current transformers on the LV side. In this example, the current transformers have a nominal current of 300/5 A.

Due to the fact that the step-up transformer is a Dz4, there will be a phase angle twist of -120 °.

These settings can be programmed via the display or the utility software. These settings must be put into the parameters shown in the table below:

Parameter	Comment	Setting
6002	Generator nominal power	140
6003	Generator nominal current	250
6004	Generator nominal voltage	400
6041	LV measurement transformer primary side (There is none here)	400
6042	LV measurement transformer secondary side (There is none here)	400
6043	Current transformer primary side	300
6044	Current transformer secondary side	5
6051	HV (BB) measurement transformer primary side	10000
6052	HV (BB) measurement transformer secondary side	100
6053	Nominal HV setting of step-up transformer	10000
9141*	Phase angle compensation	120 °

NOTE * This parameter is for busbar parameter set 1. Use parameter 9142 for busbar parameter set 2.

NOTE The ML-2 controller can directly handle voltage levels between 100 and 690 V. If the voltage level in the application is higher or lower, it is required to use measurement transformers that transform the voltage into a number between 100 and 690 V.

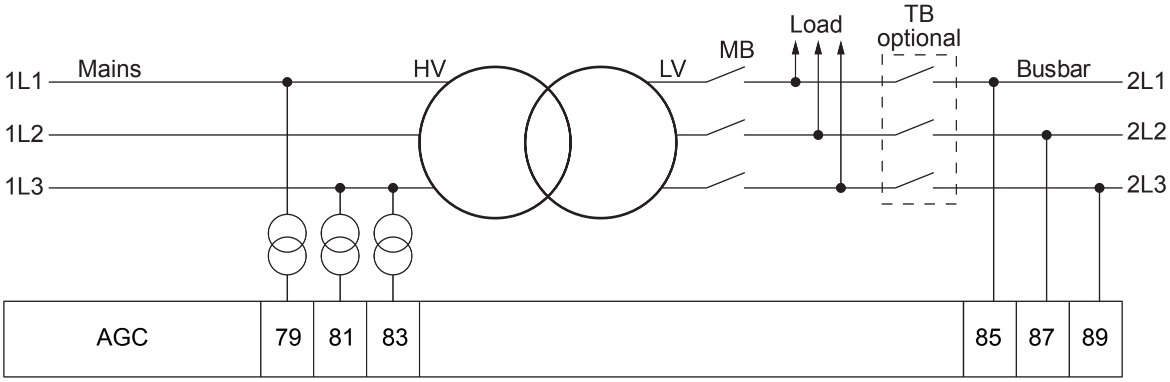
9.36.4 Vector group for step-down transformer

In some applications, there may also be a step-down transformer. This could be to transform a grid voltage down, so the load can handle the voltage level. The controller is able to synchronise the busbar with the mains, even if there is a step-down transformer with a phase angle twist. The transformer must be between the measuring points for the controller. If a step-down transformer is used, these settings must be set in parameter 9141 to compensate the phase angle twist.

Vector group	Step-up transformer types	Parameter 9141
0	Yy0, Dd0, Dz0	0 °
1	Yd1, Dy1, Yz1	-30 °
2	Dd2, Dz2	-60 °
4	Dd4, Dz4	-120 °
5	Yd5, Dy5, Yz5	-150 °
6	Yy6, Dd6, Dz6	180 °
7	Yd7, Dy7, Yz7	150 °
8	Dd8, Dz8	120 °
10	Dd10, Dz10	60 °
11	Yd11, Dy11, Yz11	30 °

NOTE If a step-down transformer is mounted with a genset controller, the settings shown in the table above should also be used.

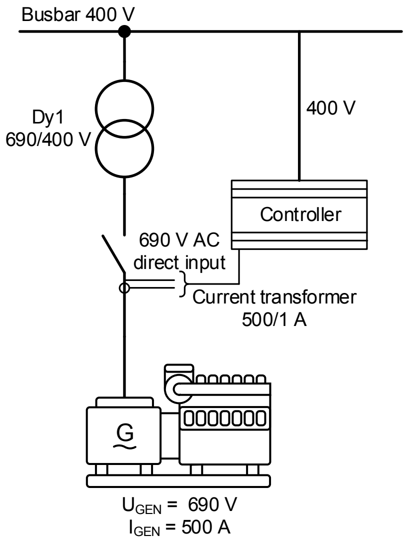
If a step-down transformer and mains controller are mounted, note how the measurements are mounted on the controller. The correct connection is shown below.



NOTE The connection shown in the picture should always be used when a controller is used for a mains breaker.

9.36.5 Setup of step-down transformer and measurement transformer

If the HV side of the transformer has a voltage level higher than 690 V AC, it will be necessary with measurement transformers. In this example, the HV side is 690 V, and therefore there is no need for a measurement transformer. The step-down transformer can have a phase angle twist, which must be compensated for. The setup of all the parameters can be done from the utility software, and will be explained by an example:



- The transformer is a Dy1 step-down transformer, with nominal settings of 690/400 V.
- The generator has a nominal voltage of 690 V, nominal current of 500 A and a nominal power of 480 kW.
- There is no measurement transformer in this application, because the ML-2 is able to handle the voltage levels directly.
- The nominal voltage of the busbar (BB) is 400 V.

It is still required to set up current transformers. In this example, the current transformers have a nominal current of 500/1 A. Due to the fact that the step-down transformer is a Dy1, there will be a phase angle twist of +30 °.

These settings can be programmed via the display or the utility software. These settings must be put into the parameters shown in the table below:

Parameter	Comment	Setting
6002	Generator nominal power	480
6003	Generator nominal current	500
6004	Generator nominal voltage	690
6041	HV measurement transformer primary side (There is none here)	690

Parameter	Comment	Setting
6042	HV measurement transformer secondary side (There is none here)	690
6043	Current transformer primary side	500
6044	Current transformer secondary side	1
6051	LV (BB) measurement transformer primary side (There is none here)	400
6052	LV (BB) measurement transformer secondary side (There is none here)	400
6053	Nominal LV setting of step-up transformer	400
9141	Phase angle compensation	-30 °

9.37 Demand of peak currents

9.37.1 I thermal demand

This measurement is used to simulate a bimetallic system, known from the Maximum Demand ammeter, which is specifically suited for indication of thermal loads in conjunction with cables, transformers, and so on.

It is possible to have two different readouts shown in the display. The first readout is called I thermal demand. This readout shows the average **maximum** peak current over an adjustable time interval.

NOTE Be aware that the calculated average is NOT the same as the average current over time. The I thermal demand value is an average of the MAXIMUM PEAK current in the adjustable time interval.

The measured peak currents are sampled once every second, and every 6 seconds an average peak value is calculated. If the peak value is higher than the previous maximum peak value, it is used to calculate a new average. The thermal demand period will provide an exponential thermal characteristic.

The time interval in which the average maximum peak current is calculated can be adjusted in parameter 6840. The value can also be reset. If the value is reset, it will be logged in the event log and the readout in the display is reset to 0.

9.37.2 I max. demand

The second readout is called I maximum demand, and shortened in the controller, I max. demand. The readout displays the newest maximum peak current value. When a new maximum peak current is detected, the value is saved in the display. The value can be reset in menu 6843. If the value is reset, it will be logged in the event log.

NOTE The two reset functions are also available as commands through M-Logic (*Output, Command, Reset I max demand* and *Reset I thermal demand*).

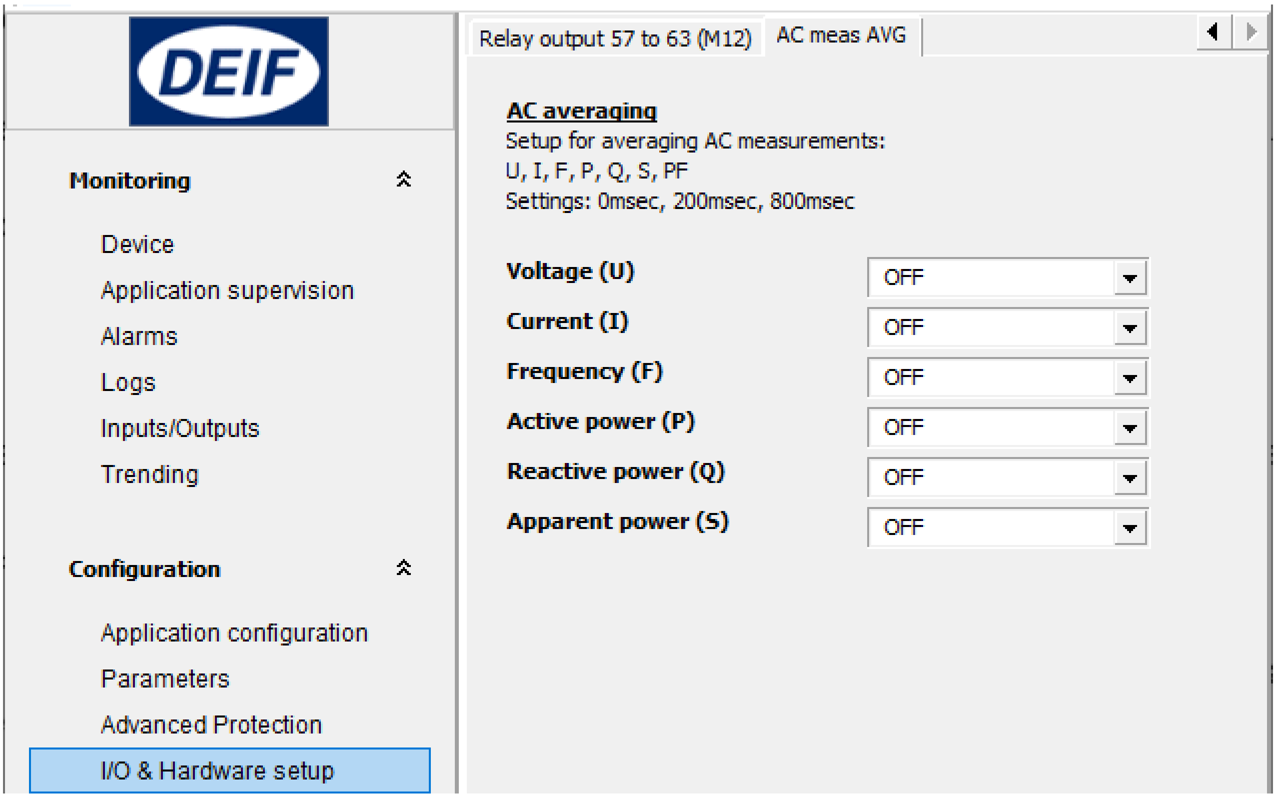
NOTE Display readout is updated with an interval of 6 seconds.

9.38 AC averaging

9.38.1 AC measurement averaging

You can use the utility software to set up averaging for a number of AC measurements. The averaged values are then shown on the display unit and in the Modbus values. However, the controller continues to use real-time measurements.

In the utility software, under *I/O & Hardware setup*, select the *AC meas AVG* tab. For each measurement, you can select no averaging (0 ms), averages calculated over 200 ms, or averages calculated over 800 ms.



9.38.2 AC average alarms

An alarm is activated if the average of a specific measurement exceeds the set point for a certain time.

In principle, the average calculation is done every time the measurement updates, for example, the voltage. The average is based on the RMS value of the three phases.

There are two levels for each alarm. You can use the USW to configure these alarms.

Parameter	Item
14000	Avg G U> L-L 1
14010	Avg G U> L-L 2
14020	Avg G U< L-L 1
14030	Avg G U< L-L 2
14040	Avg G U> L-N 1
14050	Avg G U> L-N 2
14060	Avg G U< L-N 1
14070	Avg G U< L-N 2
14080	Avg G f> 1
14090	Avg G f> 2
14100	Avg G f< 1
14110	Avg G f< 2
14120	Avg I> 1
14130	Avg I> 2

NOTE You cannot configure these alarms from the display.

9.39 Counters

9.39.1 Counter parameters

Counters for various values are included, and some of these can be adjusted if necessary, for instance if the controller is installed on an existing genset or a new circuit breaker has been installed.

The table shows the adjustable values and their function in menu 6100:

Parameter	Name	Function	Comment
6101	Running time	Offset adjustment of the total running hours counter.	Counting when the running feedback is present.
6102	Running time	Offset adjustment of the total running thousand hours counter.	Counting when the running feedback is present.
6103	GB operations	Offset adjustment of the number of generator breaker operations.	Counting at each GB close command.
6104	MB operations	Offset adjustment of the number of mains breaker operations.	Counting at each MB close command.
6105	kWh reset	Resets the kWh counter.	Automatically resets to OFF after the reset. The reset function cannot be left active.
6106	Start attempts	Offset adjustment of the number of start attempts.	Counting at each start attempt.

NOTE Additional counters for *Running hours* and *Energy* can be read out from the utility software .

9.39.2 Pulse input counters

Two configurable digital inputs can be used for counter input. The two counters can, for example, be used for fuel consumption or heat flow. The two digital inputs can ONLY be configured for pulse inputs via M-Logic, as shown in the example below.

- Scaling of pulse input can be set in menu 6851/6861. It is possible to determine the scale value to be pulse/unit or unit/pulse.
- Counter values can be read out in display, and the number of decimals can be adjusted in menu 6853/6863.

NOTE The controller can detect 4 to 5 pulses per second.

9.39.3 kWh/kvarh counters

The controller has two transistor outputs, each representing a value for the power production. The outputs are pulse outputs, and the pulse length for each of the activations is 1 second.

Term. number	Output
20	kWh
21	kvarh
22	Common terminal

The number of pulses depends on the actual adjusted setting of the nominal power:

Generator power	Value	Number of pulses (kWh)	Number of pulses (kvarh)
P_{NOM}	<100 kW	1 pulse/kWh	1 pulse/kvarh
P_{NOM}	100 to 1000 kW	1 pulse/10 kWh	1 pulse/10 kvarh
P_{NOM}	>1000 kW	1 pulse/100 kWh	1 pulse/100 kvarh

NOTE The kWh measurement is shown in the display as well, but the kvarh measurement is only available through the transistor output.

NOTE Be careful - the maximum burden for the transistor outputs is 10 mA.

9.39.4 M-Logic counters

More information
See **M-Logic event counters** in **Application notes M-Logic AGC-4 Mk II**.

9.40 KWG ISO5 isolation monitor

If you have option H12, you can connect a KWG ISO5 isolation monitor to the CAN bus terminals. The controller can then receive the insulation resistance.

You can add the insulation resistance to a view in the controller display. You can also use the insulation resistance in an analogue input alarm. You can use Modbus and M-Logic to communicate with the KWG ISO5.

Configuration

If no ECU is connected to the CAN bus terminals, select *KWG ISO5 isolation monitor* in *Engine I/F* (parameter 7561).

If a J1939 ECU is connected and selected in parameter 7561, the controller automatically detects the KWG ISO5.

Viewing the insulation resistance

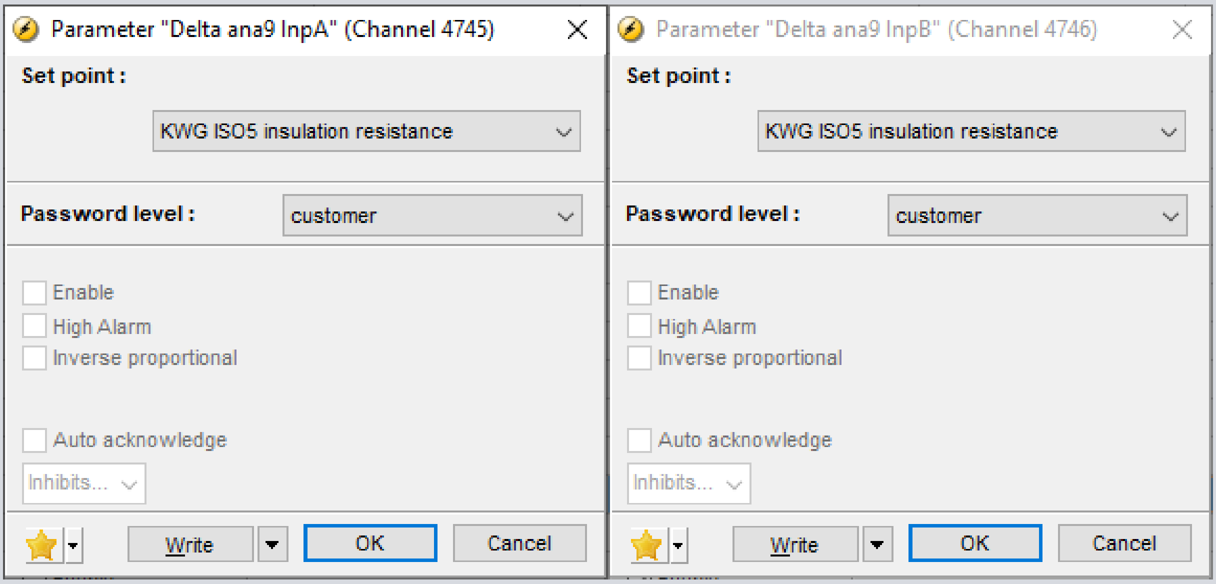
In the utility software, under *Configuration of the user views*, select a view, then select a view line. Select *Engine communication, Isolation monitor, KWG ISO5 isolation monitoring*.

Creating an insulation resistance alarm

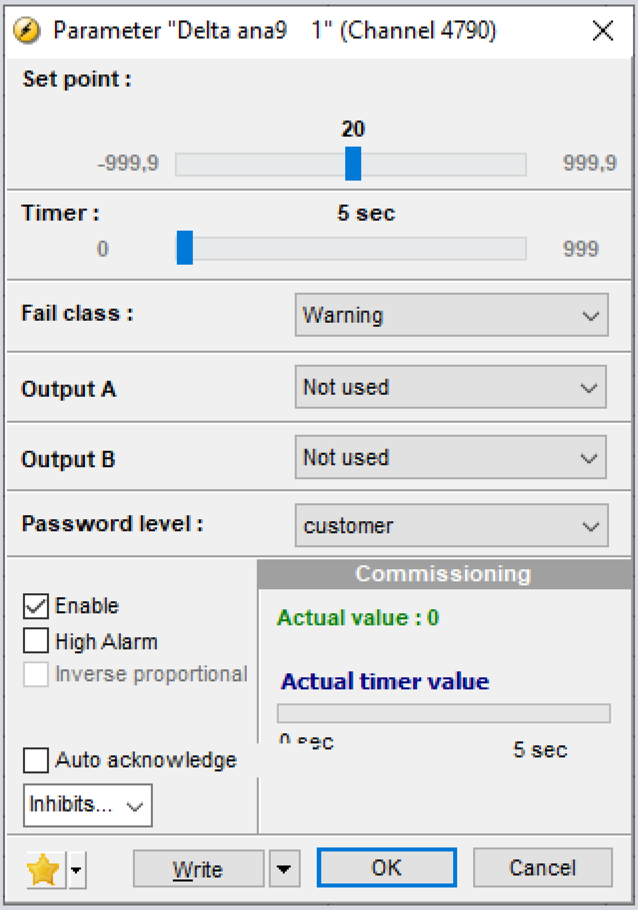
You can use the differential measurement function to create an insulation resistance alarm.

Example: Activate an alarm when the insulation resistance is below 20 kΩ

In *Delta ana9 InpA* (parameter 4745) and *InpB* (4746), select *KWG ISO5 insulation resistance*.



In *Delta ana9 1* (4790), configure the alarm.



NOTE To activate the alarm when the resistance is below 20 kΩ, this is not a *High alarm*.

M-Logic commands

`Output, EIC commands`

Command	Details
EIC KWG ISO5 test telegram	The controller sends a test telegram to the KWG ISO5.
EIC KWG ISO5 reset telegram	The controller sends a reset telegram to the KWG ISO5.
EIC KWG ISO5 buzzer reset telegram	The controller sends a buzzer reset telegram to the KWG ISO5.

M-Logic events

`Events, EIC event`

Event	Details
KWG ISO5 - Isolation fault	The KWG ISO5 has detected an isolation fault.
KWG ISO5 - Isolation warning	The KWG ISO5 is sending an isolation warning.
KWG ISO5 - Isolation timeout	The controller cannot connect to the KWG ISO5.

More information
See **External I/O module CIO/IOM (option H12.2/H12.8)** in the **Installation instructions** for wiring information.

9.41 Unsupported application

The controller has configuration limitations. If a configuration rule is broken, the controller activates the *Unsupported application* alarm or *Wrong breaker config.* alarm. The alarm value shows which rule was broken. You can see the alarm value in the alarm log in the utility software (open the *Logs* page, and get the *Alarm logs*).

Alarm value	Configuration rule
1	For standard controller applications, the controller must have the power management option.
2	It is not possible to configure a single controller application with a mains controller or a BTB controller.
4	Multi-mains application with either group mains or top mains configured.
7	Unknown application type.
8	The controller must have the emulation option enabled to activate emulation.
10	The number of controllers in a plant exceeds the maximum number of allowed controllers.
12	For single controller applications with an external generator breaker both feedbacks must be configured.
13	For single controller applications with an external mains breaker both feedbacks must be configured.
29	There is an internal CAN protocol conflict.
36	There cannot be a mains in the application configuration when PMS lite is enabled.
37	CANshare and PMS lite cannot run on the same CAN line.

Alarm log example

TimeStamp	Line	Text	Channel	PPower	QPower	PF	Gen. U1	Gen. U2	Gen. U3	Gen. I1	Gen. I2	Gen. I3	Gen. F	Bus U1	Bus U2	Bus U3	Bus F	df/dt	Vector	Multi input 102	Multi input 105	Multi input 108	Tacho	Alarm value
2023-08-25 10:39:57.300	0	Unsupported appl.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	36

10. General purpose PID

10.1 Introduction

The general purpose PID controllers use the same principles as the PID controllers for AVR and governor output. They consist of a proportional, integral and derivative part. The integral and derivative parts are dependent on the proportional gain. A description of the principles can be found in the chapter about controllers for AVR and governor. The relay control is also described in the chapter about AVR/governor control.

Note that the GP PIDs are slightly less responsive. These controllers are meant for temperature regulation, controlling fans, valves, and so on.

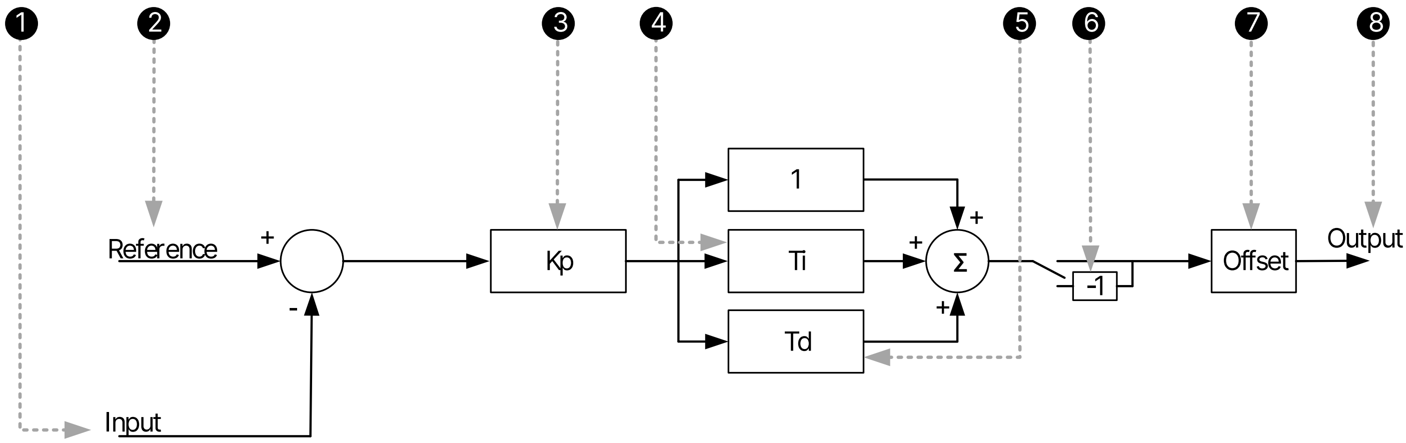
This section describes options in the GP PID interface, with some configuration examples.

Acronyms

- GP: General purpose
- SP: Set point
- PV: Process variable

10.1.1 General purpose PID analogue loop

The analogue regulation in the general purpose PIDs is handled by a PID loop. The diagram below shows the elements in the PID loop



1. **Input:** This is the analogue input that measures the process that the controller is trying to regulate. See *Input* later in this document.
2. **Reference:** This is the set point that the controller is trying to regulate the input to match. See *Input* later in this document.
3. **Kp:** The proportional gain of the PID loop. See *Output* later in this document.
4. **Ti:** The integral gain of the PID loop.
5. **Td:** The derivative gain of the PID loop.
6. **Inverse:** Enabling inverse gives the output a negative sign. See *Output* later in this document.
7. **Offset:** The offset is added to the function and displaces the regulation range. See *Output* later in this document.
8. **Output:** This is the final output from the PID, which controls the transducer.

10.1.2 GP PID interface in USW

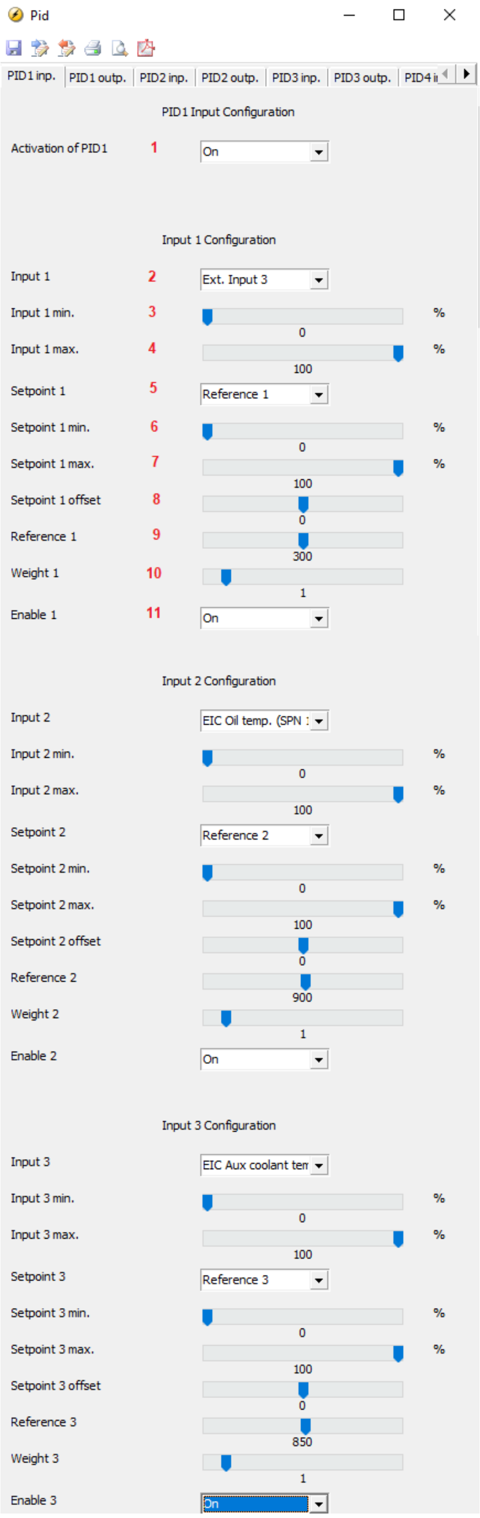
Use the PID button (PID) in the utility software to configure the GP PID's input and output settings.

10.2 Inputs

10.2.1 Inputs

Each output can have up to three inputs. Only one input at a time is used for calculation of output signal. See **Dynamic input selection** for how the selection is handled.

Explanation of GP PID settings



1. **Activation of PID[#]**: Enables the PID, or allows it to be enabled from M-Logic.
2. **Input 1**: Select the source of this input here. Options include controller analogue inputs, external analogue inputs, and EIC measurements.
3. **Input 1 min.**: The lower end of the scale for the input.
4. **Input 1 max.**: The upper end of the scale for the input.
5. **Setpoint 1**: Select **Reference 1** to define the set point in this box. Alternatively, select a set point source (from the same options as **Input 1**).
6. **Setpoint 1 min.**: The lower end of the scale for the set point.
7. **Setpoint 1 max.**: The upper end of the scale for the set point.
8. **Setpoint 1 offset**: The offset for set point 1.
9. **Reference 1**: Select the GP PID set point (**Reference 1** must be chosen for **Setpoint 1**) for this input.

   NOTE The set point uses scaling. For example, for a temperature of 30 °C, the set point is **300**.
10. **Weight 1**: The input value is multiplied by the weight factor.
    - A weight factor of 1 means that the real input value is used in the calculations.
    - A weight factor of 3 means that the input value is three times as big in the calculations.
11. **Enable 1**
    - On: This input is evaluated.
    - Off: This input is not evaluated.

10.2.2 Dynamic input selection

Each GP PID can have up to three active inputs. All activated inputs are evaluated continuously. The input that causes the biggest or smallest output is selected. Whether the biggest or smallest output is selected in the output settings.

Example explaining dynamic input selection

A realistic example of dynamic input selection is for the ventilation of a container with a genset inside. The following three variables are affected by the ventilation, and it therefore it makes sense that they share the output.

- The container includes a sensor for the internal container temperature. To ensure the lifetime of the electronics inside the container, the maximum temperature is 30 °C. (Input 1).
- The engine air intake is inside the container. The turbo compressor inlet temperature therefore depends on the air temperature in the container. The maximum intake air temperature is 32 °C. (Input 2).
- The alternator is cooled by air in the container. The alternator winding temperature therefore depends on the air temperature in the container. The maximum winding temperature is 130 °C. (Input 3).

This data is used to configure the inputs in the screenshot above (Inputs). All inputs are configured with the full range of measurement (0 to 100 %) and a weight factor of 1. The common output to the ventilator speed drive is configured to prioritise maximum output as explained in **Output**. This configuration ensures that none of the input set points are continuously exceeded, unless maximum ventilation is reached.

For example, during operation, the controller has been using input 1, and a temperature of 30 °C is maintained in the container. At a point, the air filter housing is heated by radiation from the engine. This makes input 2 to rise more above 32 °C than input 1 is above 30 °C. Input 2 now has the greatest positive deviation. All inputs are configured with a weight factor of 1 and the maximum output is prioritised. The greatest positive deviation results in the maximum output, and so input 2 is selected.

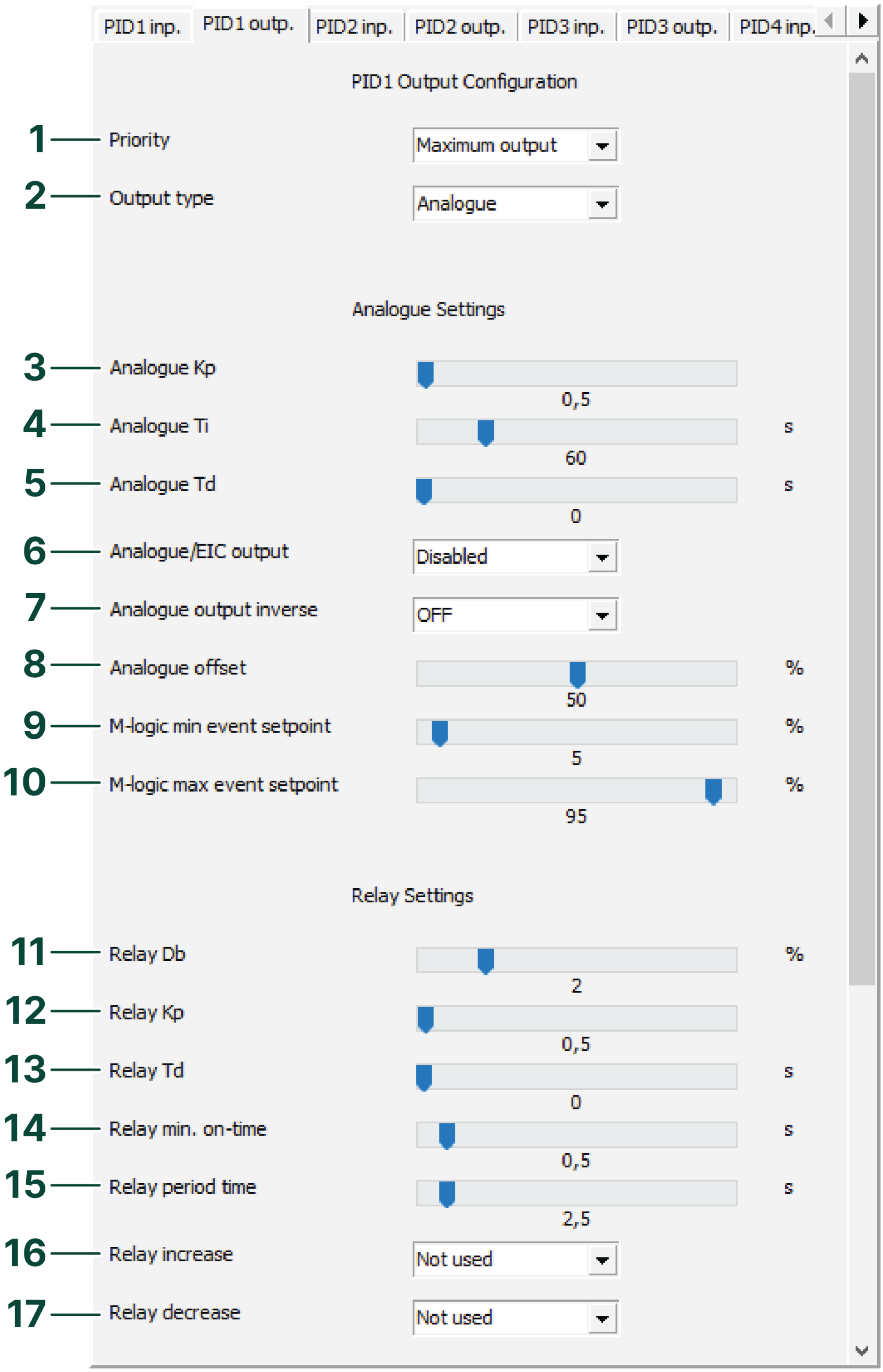
Later, the genset is running at full load with a maximum of reactive load. Due to high currents, the alternator windings heat up beyond the 130 °C set point. At some point, input 3 give the maximum output, and therefore be selected as the input used in output calculation. Ventilation is increased. The winding temperature may reach a steady state of 130 °C with a container room temperature of 27 °C and a compressor inlet temperature of 30 °C. As long as this is the situation, input 3 remains the selected input, as this is the input that causes the greatest output.

For high ambient temperatures, the ventilation might not be able to influence the temperature enough, so that the temperatures start to rise above set point. The output stays at 100 % as long as any of the inputs are continuously above their set points.

The weight factor also applies to dynamic input selection. If any of the three inputs have different weight factors, the maximum deviation is not necessarily the maximum output. If two inputs with a similar deviation to their respective set points have weight factors of 1.0 and 2.0 respectively, the latter has twice the output.

10.3 Output

10.3.1 Explanation of output settings



1. Priority

This setting is used for the dynamic input selection feature. *Maximum output* selects the input that gives the greatest output. *Minimum output* selects the input that gives the smallest output.

2. Output type

Choose *Relay*, *Analogue* or *EIC* output. The following parameters marked *analogue* only apply for analogue and EIC regulation. Parameters marked *relay* only apply to relay regulation.

3. Analogue Kp

This is the proportional gain value. Increasing this value gives a more aggressive reaction. Adjusting this value also affects the integral and derivative output. If Kp needs adjustment without affecting the Ti or Td part, adjust Ti and Td accordingly.

4. Analogue Ti

Increasing the Ti results in less aggressive integral action.

5. Analogue Td

Increasing the Td gives more aggressive derivative action.

6. Analogue/EIC output

Choose an output from the drop-down list.

If **Analogue** is selected under *Output type*, you can select:

Transducer [68/70 PWM/72]: Controller outputs.

Ext Ana. Out [1 to 8]: The eight CIO 308 analogue outputs.

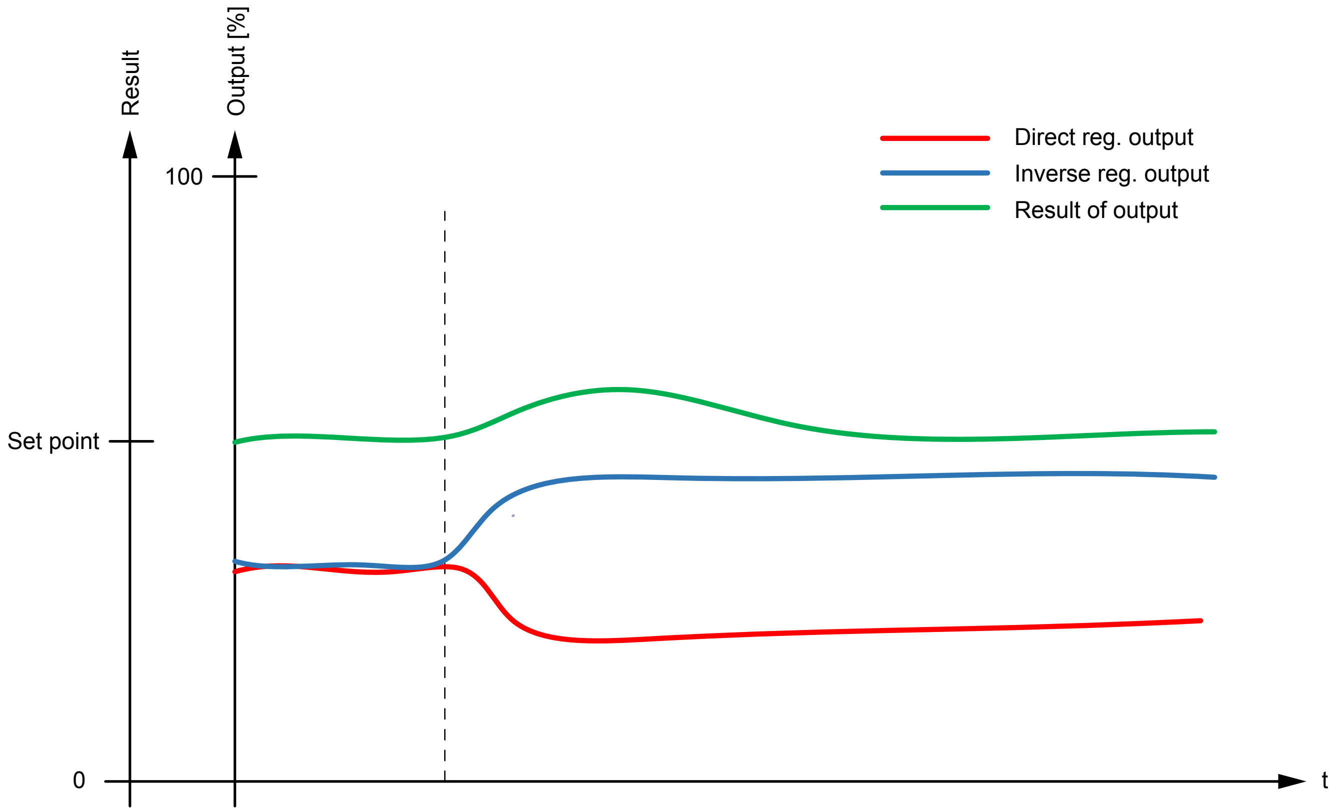
IOM2xx ID [0 to 2] AO [1 to 2]: IOM 220/230 analogue outputs.

- Up to three IOMs can be used as PID outputs. Use the IOM ID selection dip switches to select each IOM ID. See the **IOM 200 Data sheet** for details.
- Two analogue outputs can be used on each IOM. AO 1 is terminals 7-8, and AO 2 is terminals 9-10.
- The IOMs can be in series with an ECU and/or other equipment that uses CAN bus communication.
- The IOMs are detected automatically if a J1939 engine protocol is selected in parameter 7561. If there is no ECU, select *IOM2xx* in parameter 7561.

If **EIC** is selected under *Output type*, you can select *Disabled* or *Fan speed (SPN 986)*.

7. Analogue output inverse

Enabling this inverses the output function.



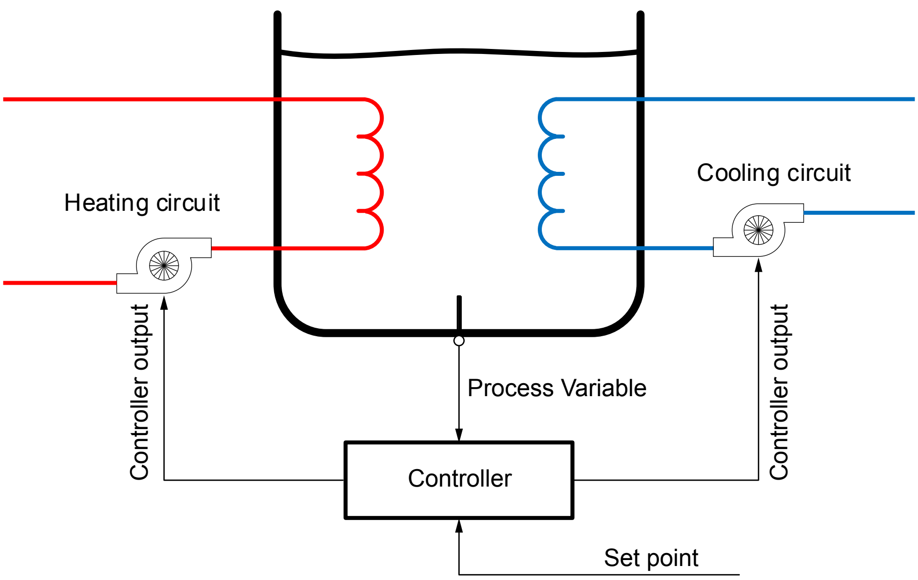
- Direct error = Set point - Process variable
- Inverse error = Process variable - Set point

Direct output is used in applications where a rise in the analogue output increases the process variable.

Inverse output is used in applications where a rise in the analogue output decreases the process variable.

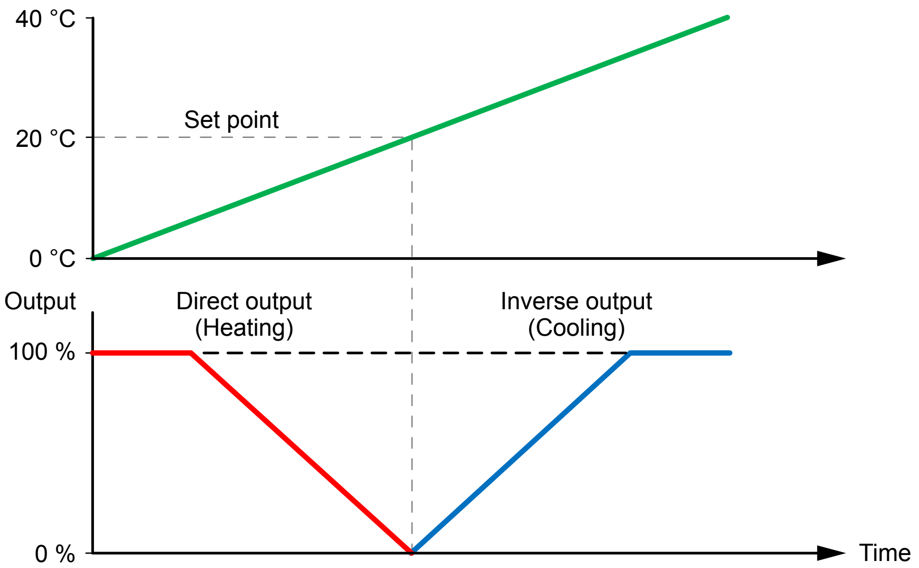
Example explaining direct and indirect regulation

Typically, heating applications use direct output, and cooling applications use inverse output. Imagine a container of water, which must be kept at 20 °C. The container can be exposed to temperatures between 0 and 40 °C. It therefore has both a heating coil and a cooling coil, as shown below.



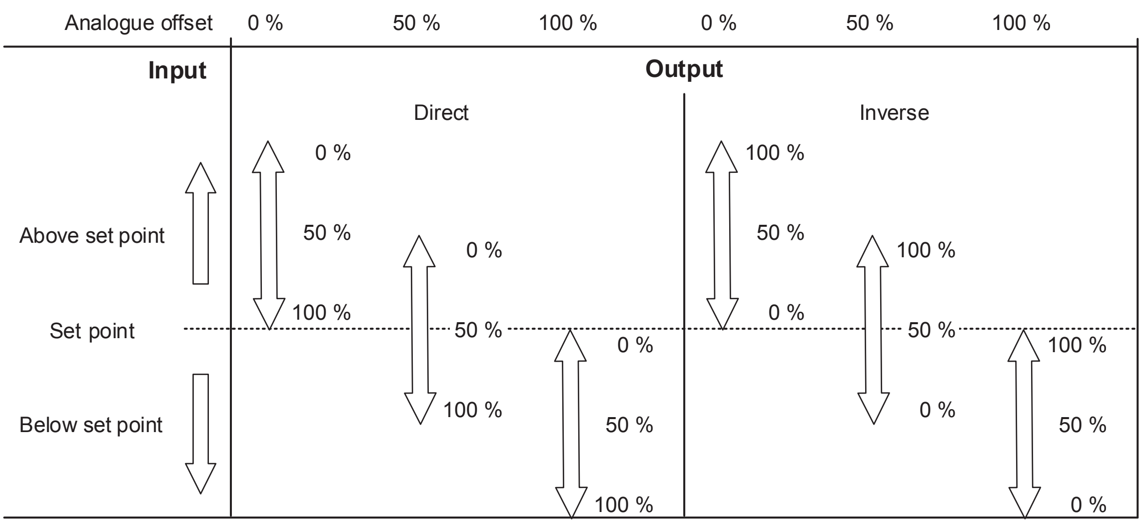
For this application, two controllers must be configured. one with a direct output for the heating pump and one with an inverse output for the cooling pump. To achieve the inverse output shown, an offset of 100 % is needed. See **Analogue offset** and **Example of inverse output with 100 % offset** for more information.

Temperatures below 20 °C then give in a positive output for the heating pump. Similarly, temperatures above 20 °C give a positive output for the cooling pump. The temperature is therefore kept at the set point.



8. Analogue offset

The offset determines the output starting point. The full range of output can be from 0 to 100 %. The offset displaces this range. 50 % offset centres the range of the output at the set point. Offsets of 0, and 100 % result in the full range of output above, or below the set point, respectively. See below for how the inputs, with different offsets, affect the outputs.



An offset of 100 % is commonly used with inverse output, like in the previous cooling example. See also **Example of inverse output with 0 % offset**.

9. M-Logic min event set point

The controller activates *Events > General Purpose PID > PID# at min output* in M-Logic.

10. M-Logic max event set point

The controller activates *Events > General Purpose PID > PID# at max output* in M-Logic.

11. Relay Db

Deadband setting for relay control.

12. Relay Kp
Proportional gain value for relay control.

13. Relay Td
Derivative output for relay control.

14. Relay min on-time
Minimum output time for relay control. Set this to the minimum time that is able to activate the controlled actuator.

15. Relay period time
Total time for a relay activation period. When the regulation output is above this period time, the relay output is continuously activated.

16. Relay increase
Choose the relay used for positive activation.

17. Relay decrease
Choose the relay used for negative activation.

10.4 Kp gain compensation

10.4.1 Introduction

This document describes the functionality regarding the "Kp gain compensation", so it is possible to utilise the function parameters and help with setting up the function. This function is intended to be used when the AGC is controlling the cooling water system for the genset.

As it is today, there are two situations in which the engine is in danger of ending in an oscillation that could shut down the engine:

1. Load impacts
2. Cold start of engine

In both situations, it is desired to have a higher gain when the change is needed, but a lower gain when the system has to stabilise. Without "Kp gain compensation", the PID settings need to be balanced between reaction and stability. The "Kp gain compensation" function allows slower PID settings for when there are no changes or stabilising, and when there are significant changes in the system it will increase the reaction of the PID.

The "Kp gain compensation" consists of two separate functions:

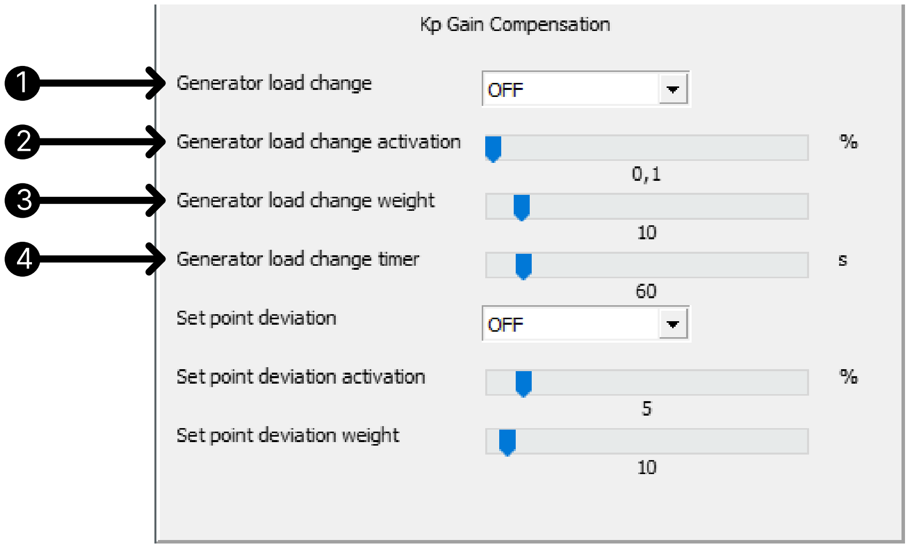
1. The load change gain compensation.
2. Set point deviation compensation.

These two functions, the load-dependent compensation and the set point deviation compensation, can be used separately or together. If they are used together, it is always the one with the highest returned gain that is used.

10.4.2 Load change gain compensation

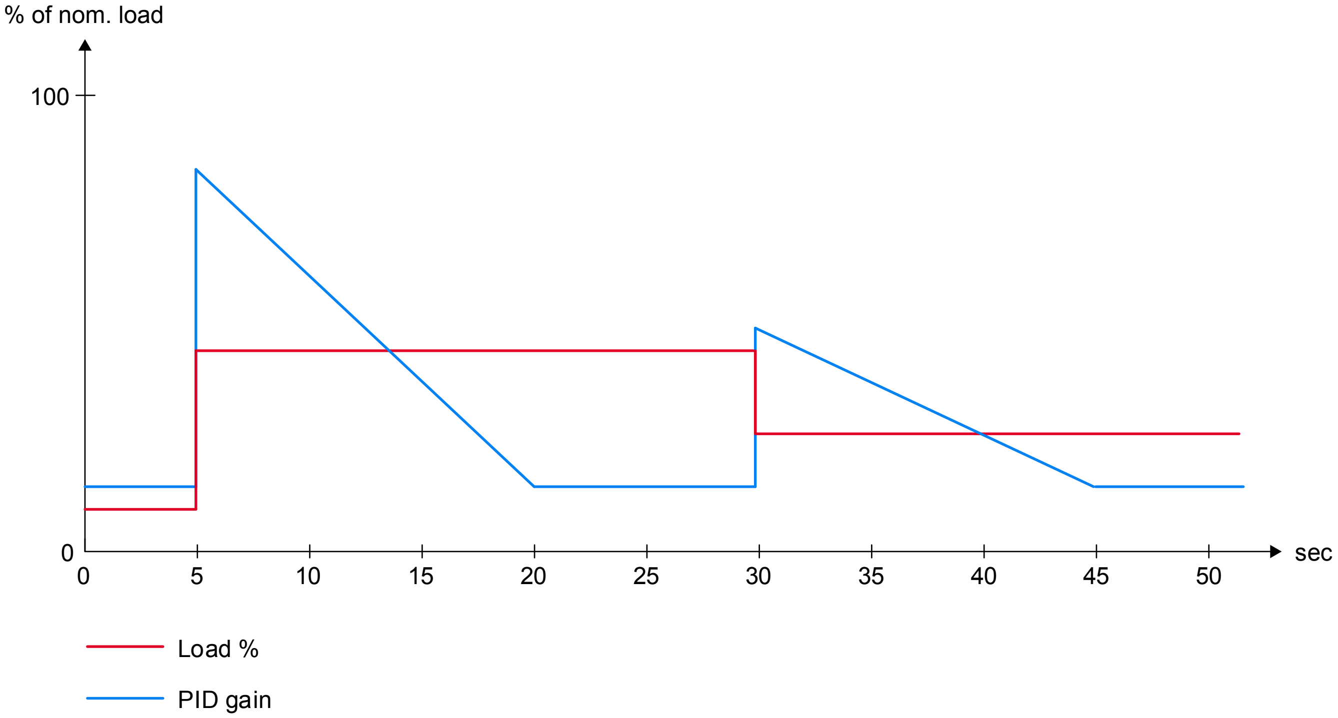
In case of large load impacts or rejections, it can create large deviation in the need of cooling, and thereby create some instability in the cooling system. To alleviate some of this instability, the load change gain compensation will instantaneously increase the gain in relation to the load gain. Larger load changes give a bigger increase in gain. This increase in gain will decrease over a set time till it reaches the nominal gain.

Explanation of settings



1. **Generator load change**: Enables/disables load change compensation.
2. **Generator load change activation**: Load change limit. The controller needs to detect a load change larger than this limit before activating the gain compensation. For example, if the limit is set for 10 %, there must be a load impact or rejection of at least 10 % of the genset nominal power before this function activates.
3. **Generator load change weight**: The gain increase is based on the load change compared to nominal, and this ratio is multiplied by the load weight.
4. **Generator load change timer**: The gain increase will be instantaneous, but it will decrease linearly over the set time until it reaches nominal gain.

Example of load change gain compensation



The diagram above shows the reaction of the gain, based on two load changes.

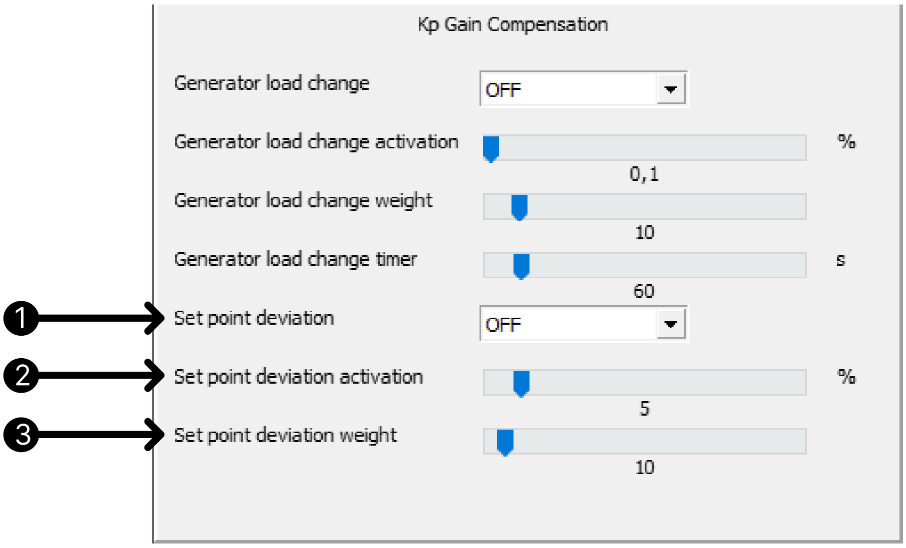
In the first situation, there is a large load impact that triggers the load change gain compensation and increases the gain instantaneously. This increase will decrease, in this case over 15 seconds, and bring the gain back to nominal.

After some seconds, the system drops some load again, but only half of the former impact. Gain is again instantaneously increased, but this time only half as much because the load change is only half as big. The increase will still decrease over 15 seconds.

10.4.3 Set point deviation compensation

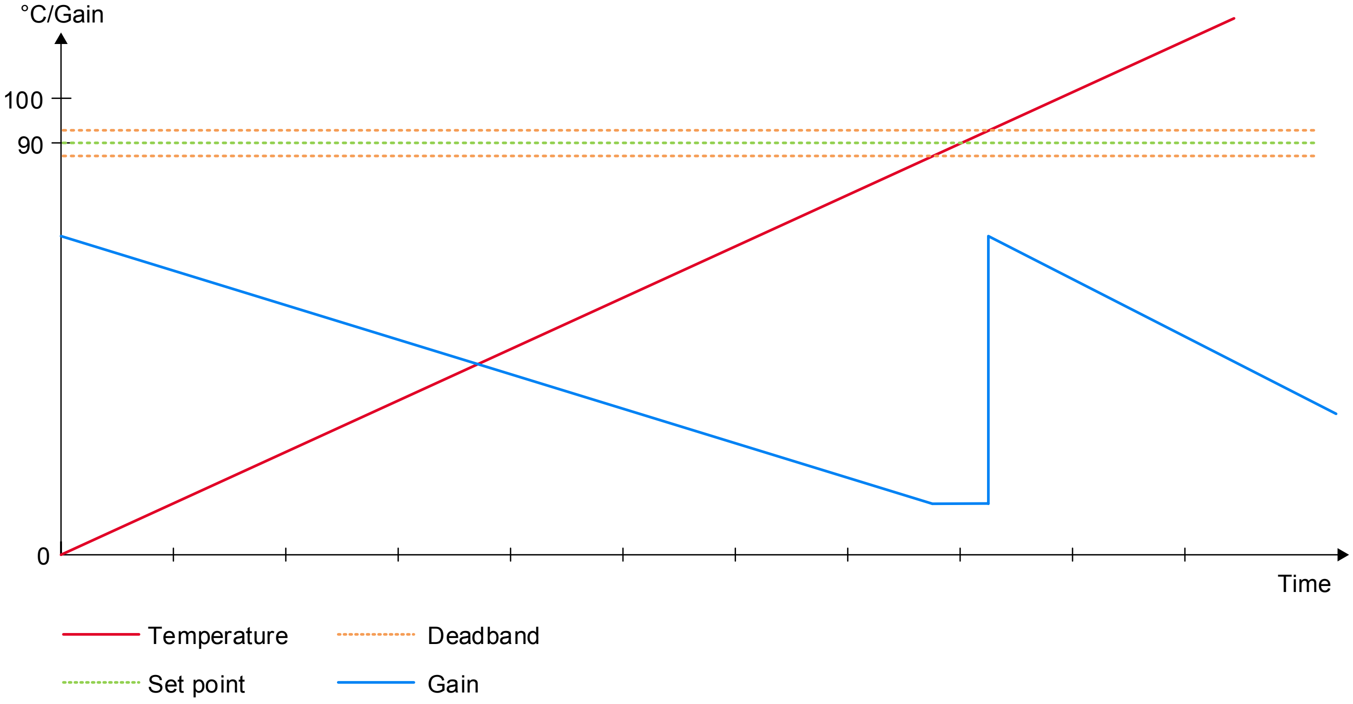
This function is intended to help minimise overshoots. Especially in a cooling water system where the set point is often very close to the shutdown limit, it is difficult for a slow system to react in time to avoid a shutdown. This function will drastically increase the gain when the actual value overshoots the set point more than the set deadband, but the further the actual value is from the set point, it will decrease. If the value drops below the set point, the function works reversed. Close to set point, the gain increase is small, but the further the actual value is from the set point, it will increase. This is to avoid that the system starts hunting.

Explanation of settings



1. **Set point deviation**: Enables/disables set point deviation compensation.
2. **Set point deviation activation**: Deviation deadband. As long as the actual value does not deviate more than the deadband in this parameter, the function is not activated.
3. **Set point deviation weight**: The gain increase is based on the set point deviation compared to nominal, and this ratio is multiplied by the weight factor.

Example of set point deviation compensation



The diagram above shows how the reaction to a set point deviation could look.

This situation could be rising cooling water temperature in a genset. Below the set point, the gain is very high, but as the temperature is getting closer to the set point, it decreases the gain compensation. Within the activation limit, the gain is at nominal value.

As the temperature keeps rising, it exceeds the activation limit again, and when it is above set point the gain is increased instantaneously. As the temperature keeps rising, the gain compensation decreases again.

10.5 M-Logic

10.5.1 Introduction

All functions of the GP PIDs can be activated and deactivated by means of M-Logic. In the following, events and commands regarding the GP PIDs are described.

10.5.2 Events

M-Logic, Events, General Purpose PID	Notes
PID [1-6] active	Activated when the PID is active.
PID [1-6] at min. output	Activated when the PID is at minimum output (below the output parameter *M-Logic min event set point*).
PID [1-6] at max. output	Activated when the PID is at maximum output (above the output parameter *M-Logic max event set point*).
PID [1-6] output frozen	Activated when the PID is frozen.
PID [1-6] using input [1-3]	Activated when dynamic input selection has selected input [1-3] for output calculation.
PID [1-6] Modbus control	Activated when remote Modbus control of this PID is requested.

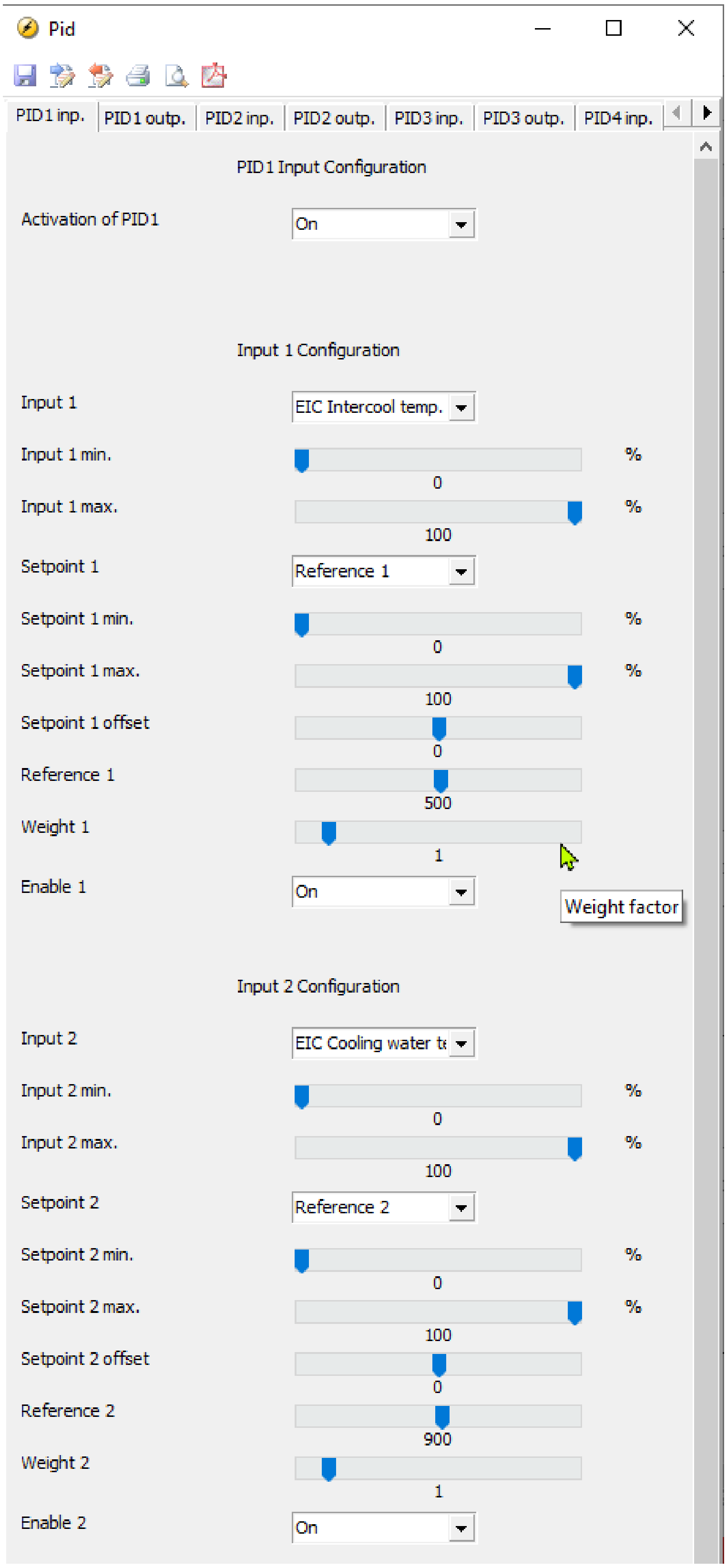
10.5.3 Commands

M-Logic, Commands, General Purpose PID commands	Notes
PID [1-6] activate	Activates the PID controller.
PID [1-6] force min. outp.	Forces the output to the value set in the output parameter *Analogue min outp.*
PID [1-6] force max. outp.	Forces the output to the value set in the output parameter *Analogue max outp.* (for example, for cooldown).
PID [1-6] reset	Forces the output to the value set in the output parameter *Analogue offset*.
PID [1-6] freeze output	Freezes the output at the current value.

10.6 Example: PID control for an engine fan

A general purpose PID can be used for analogue fan control. In this example, the fan is mounted on a radiator “sandwich” construction. The fan drags air through two radiators (one for the intercooler coolant, and one for the jacket water). As these two systems have different temperature set points, dynamic set point selection is used.

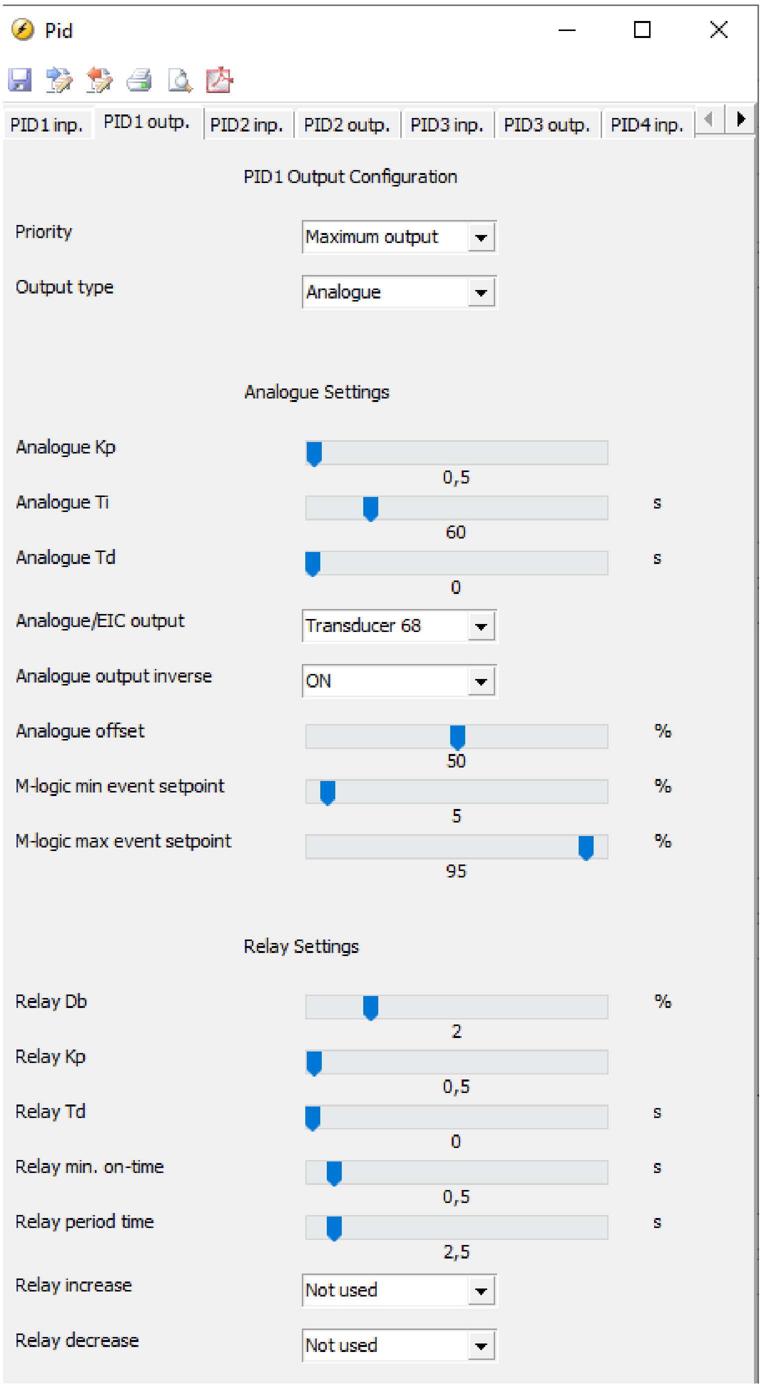
PID input configuration



In this example, the ECM (Engine Control Module) uses engine interface communication to measure the intercooler coolant temperature and the jacket cooling water temperature.

Input 1 uses the EIC Intercool temp., and input 2 uses the EIC Cooling water temp.. The minimum and maximum values are configured for full range. The Input 1 reference set point is 500, for a temperature set point of 50 °C for the intercooler coolant. The Input 2 reference set point is 900, for a set point of 90 °C for the jacket water coolant. For equal weighting of the inputs, both weight factors are **1**. Inputs 1 and 2 are activated, and input 3 (scroll down in the utility software) is deactivated.

PID output configuration



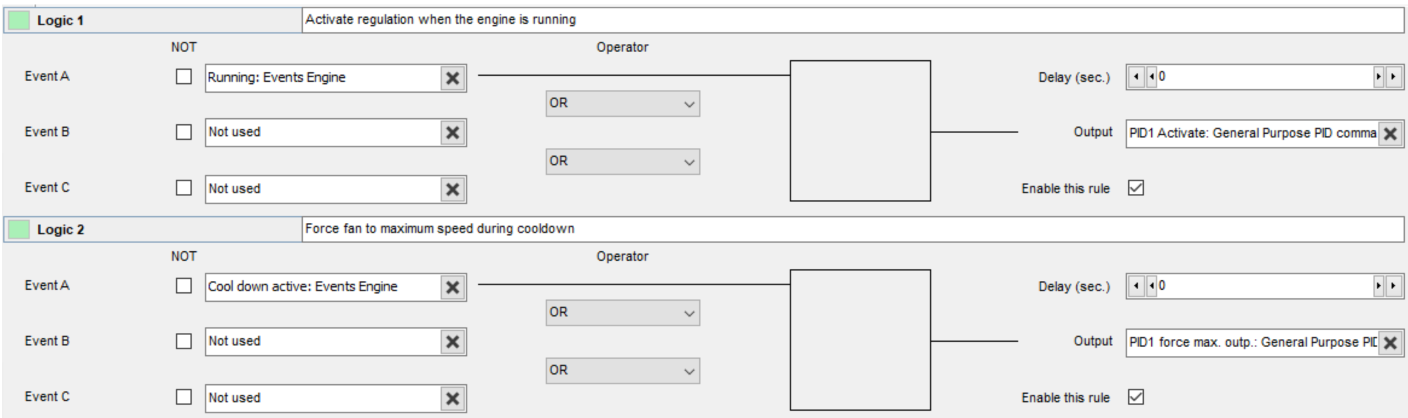
To ensure that none of the temperatures permanently exceed their set points, the configuration selects maximum output as the priority for the dynamic input selection.

In this example, **Analogue** is selected as output type, and the physical output is **Transducer 68**. Inverse output is selected so that there is a rise in analogue output to the fan when the temperature rises.

- An offset of 100 % is chosen for a 100 % output at the set point.
- The full range of output is selected. As this is output for a fan, you be prefer to use a minimum output.
- The default settings are used for the M-Logic min./max. events.
- No relay settings are configured, as this is an analogue function.

M-Logic configuration

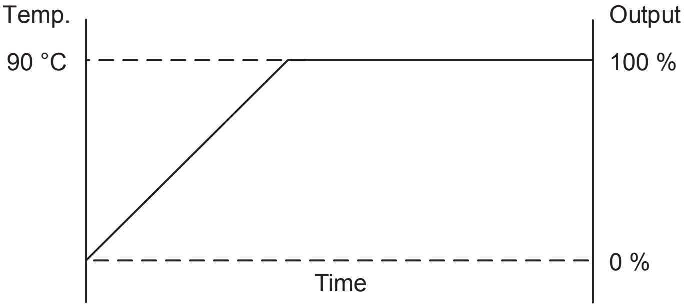
Logic 1 makes sure that the regulation is active and the output is calculated as long as the engine is running. Logic 2 forces the fan to maximum speed during cooldown, to ensure efficient cooldown.



Fan operation

When the engine is started and running, the regulation is activated and an output is calculated. When the intercooler coolant or the jacket water exceeds its set point, the output starts to increase from 0 %. The input that results in the greatest output is prioritised at all times, so that both systems are supplied with adequate cooling. During the stop sequence, the fan is forced to max. output, for the maximum cooling. After the engine stops, the output stays at 0 % until the engine is started again.

This example uses inverse output combined with a 0 % offset. The application is an engine with electric thermostat control. During engine start-up, you may want to start the output before the set point is reached, to avoid overshooting the set point too much. This is done by using inverse output with no offset. The diagram below shows this function if the controller is configured as straight proportional (without integral or derivative action). With these settings, the output is 100 % when the set point is reached. The beginning of the output is determined by the proportional gain.



11. Inputs and outputs

11.1 Digital inputs

The controller has a number of digital inputs, some of which are configurable and some are not. See the **Installation instructions** for more information.

For each digital input, use the I/O setup page in the utility software to select the digital input function.

11.1.1 Start/stop functions

Start enable

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●					Continuous

The input must be activated to be able to start the engine.

NOTE When the genset is started, the input can be removed.

Auto start/stop

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●					●	●	●	●		Continuous

The genset will start when this input is activated. The genset will be stopped if the input is deactivated. The input can be used when the controller is in island operation, fixed power, load takeover or mains power export and AUTO mode is selected.

Remote start

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
	●		●		●					Pulse

This input initiates the start sequence of the genset when semi-auto or manual mode is selected.

Remote stop

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
	●		●		●					Pulse

This input initiates the stop sequence of the genset when semi-auto or manual mode is selected. The genset stops without cooling down.

Alternative start

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●	●			●	Continuous

This input is used to simulate an AMF failure and this way run a full AMF sequence without a mains failure actually being present.

Remove starter

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●		●					Continuous

The start sequence is deactivated. This means the start relay deactivates, and the starter motor will disengage.

Low speed

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●			●					Continuous

Disables the regulators and keeps the genset running at a low RPM.

NOTE The governor must be prepared for this function.

Binary running detection

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●		●					Continuous

The input is used as a running detection of the engine. When the input is activated, the start relay is deactivated.

11.1.2 Breaker functions

NOTE Where GB/TB/BTB is used below, this refers to GB for a genset controller, TB for a mains controller, BTB for a BTB controller, and TB for a group controller.

Remote GB/TB/BTB On

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
	●		●		●	●	●	●		Pulse

- GB: The generator breaker ON sequence will be initiated and the breaker will synchronise if the mains breaker is closed, or close without synchronising if the mains breaker is opened.
- TB: The Tie breaker ON sequence will be initiated and the breaker will synchronise if the mains and generator breaker are closed, or close without synchronising if the generator breaker is open.
- BTB: The bus tie breaker ON sequence will be initiated and the breaker will synchronise if voltage is available on either or both sides of the breaker, or close without synchronising if both sides of the busbar are dead.

Remote GB/TB/BTB Off

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
	●		●		●	●	●	●		Pulse

- GB: The generator breaker OFF sequence will be initiated. If the mains breaker is opened, then the generator breaker will open instantly. If the mains breaker is closed, the generator will be deloaded to the breaker open limit followed by a breaker opening.
- TB: The tie breaker will be opened irrespective of the mains and generator breaker positions.

Remote MB On

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
	●		●		●	●			●	Pulse

The mains breaker ON sequence will be initiated and the breaker will synchronise if the generator breaker is closed, or close without synchronising if the generator breaker is opened.

Remote MB Off

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
	●		●		●	●			●	Pulse

The mains breaker OFF sequence will be initiated, and the breaker will open instantly.

GB/TB/BTB close inhibit

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●	●	●	●		Continuous

When this input is activated, the breaker cannot close.

MB close inhibit

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●	●			●	Continuous

When this input is activated, then the mains breaker cannot close.

GB/TB/BTB racked out

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
	●		●		●	●	●			Continuous

The breaker will be considered as racked out when pre-requirements are met and this input is activated (for more information, see Racked out breaker).

MB racked out

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
	●		●		●	●				Continuous

The breaker will be considered as racked out when pre-requirements are met and this input is activated (for more info, see Racked out breaker).

GB/TB/BTB spring loaded

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●	●	●	●		Continuous

The AGC will not send a close signal before this feedback is present.

MB spring loaded

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●	●			●	Continuous

The AGC will not send a close signal before this feedback is present.

GB OFF and block

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
	●				●					Pulse

The generator breaker will open, the genset will activate the stop sequence and when the genset is stopped, it will be blocked for start.

Enable GB black close

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●					Continuous

When the input is activated, the AGC is allowed to close the generator on a black busbar, providing that the frequency and voltage are inside the limits set up in menu 2110.

Enable separate sync.

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●	●	●	●	●	Continuous

Activating this input will split the breaker close and breaker synchronisation functions into two different relays. The breaker close function will remain on the relays dedicated for breaker control. The synchronisation function will be moved to a configurable relay dependent on the options configuration.

NOTE This function is option-dependent. Option M12 or M14.x is required.

11.1.3 Mode functions

Semi-auto mode

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●		●	●	●	●	●	●	●	●	Pulse

Changes the controller mode to semi-auto.

Test mode

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●		●	●	●	●		●	●	Pulse

Changes the controller mode to test.

Auto mode

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
	●	●	●	●	●	●	●	●	●	Pulse

Changes the controller mode to auto.

Manual mode

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
	●	●		●	●					Continuous

Changes the controller mode to manual.

Block mode

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●		●	●	●	●	●	Continuous

Changes the controller mode to block.

NOTE When block mode is selected, the controller mode cannot be changed by activating the digital inputs.

Total test

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●	●			●	Continuous

This input will be logged in the event log to indicate that a planned mains failure has been made.

Enable mode shift

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●	●			●	Continuous

The input activates the mode shift function, and the AGC will perform the AMF sequence in case of a mains failure. When the input is configured, the setting in menu 7081 (mode shift ON/OFF) is disregarded.

11.1.4 Regulation functions

Manual GOV up

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
			●		●					Continuous

If manual mode is selected, then the governor output will be increased.

Manual GOV down

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
			●		●					Continuous

If manual mode is selected, then the governor output will be decreased.

Manual AVR up

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
			●		●					Continuous

If manual mode is selected, then the AVR output will be increased.

Manual AVR down

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
			●		●					Continuous

If manual mode is selected, then the AVR output will be decreased.

NOTE The manual governor and AVR increase and decrease inputs can only be used in manual mode.

Reset Ana Gov output

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●					Pulse

The analogue +/-20 mA controller outputs will be reset to 0 mA.

NOTE All analogue controller outputs are reset. That is, the governor output and the AVR output. If an offset has been adjusted in the control setup, then the reset position will be the specific adjustment.

Ext. Frequency control

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●			●					Continuous

The nominal frequency set point will be controlled from the analogue inputs terminal 40/41. The internal set point will not be used. Note that a -10 V to 10 V signal is used to control and that the nominal frequency value will be located at 0 V.

NOTE With M-Logic *Gov/AVR control* it is possible to change the analogue input source to CIO 308 1.8 (4-20mA).

Ext. Power control

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●			●	●		●	●	Continuous

The power set point in fixed power will be controlled from the analogue inputs terminal 40/41. The internal set point will not be used. Note that a 0 V to 10 V signal is used for control.

NOTE With M-Logic *Gov/AVR control* it is possible to change the analogue input source to CIO 308 1.8 (4-20mA).

Ext. Voltage control

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●			●					Continuous

The nominal voltage set point will be controlled from the analogue inputs terminal 41/42. The internal set point will not be used. Note that a -10 V to 10 V signal is used for control.

NOTE With M-Logic *Gov/AVR control* it is possible to change the analogue input source to CIO 308 1.11 (4-20mA).

Ext. cos phi control

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●			●					Continuous

The cos phi set point will be controlled from the analogue inputs terminal 41/42. The internal set point will not be used. Note that a 0 V to 10 V signal is used for control.

NOTE With M-Logic *Gov/AVR control* it is possible to change the analogue input source to CIO 308 1.11 (4-20mA).

Ext. var control

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●			●					Continuous

The reactive power set point will be controlled from the analogue inputs terminal 41/42. The internal set point will not be used. Note that a -10 V to 10 V signal is used for control.

11.1.5 Other functions

Deload

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●					●					Continuous

A running genset will start to ramp down the power.

Mains OK

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●	●			●	Pulse

Disables the *Mains OK delay* timer. The synchronisation of the mains breaker will happen when the input is activated.

Access lock

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●	●	●	●	●	Continuous

Activating the access lock input deactivates the control display push-buttons. It will only be possible to view measurements, alarms and the log.

Remote alarm ack

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●	●	●	●	●	Continuous

Acknowledges all present alarms, and the alarm LED on the display stops flashing.

Shutdown override

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●					Continuous

This input deactivates all protections except the overspeed protection and the emergency stop input. The number of start attempts is seven by default, but it can be configured in parameter 6180 *Start*. Also a special cooldown timer is used in the stop sequence after an activation of this input.

Battery test

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●				●					Pulse

Activates the starter without starting the genset. If the battery is weak, the test will cause the battery voltage to drop more than acceptable, and an alarm will occur.

Temperature control

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●			●					Continuous

This input is part of the idle mode function. When the input is high, then the genset starts. It starts at high or low speed, depending on the activation of the low speed input. When the input is deactivated, then the genset goes to idle mode (low speed = ON), or it stops (low speed = OFF).

Switchboard error

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●	●				Continuous

The input stops or blocks the genset depending on running status.

Base load

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
	●				●					Continuous

The generator set runs base load (fixed power) and does not participate in frequency control. Should the plant power requirement drop, the base load is lowered so the other generator(s) on line produces at least 10 % power.

N + X on

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●					Pulse

N + X mode adds extra generator(s) to the system, that is, X generators too many will be running when comparing with the actual power requirement.

N + X off

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●					Pulse

Ends N + X mode.

Ground breaker on

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●					Continuous

When this input is activated, it indicates that ground breaker is closed.

Ground breaker off

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●					Continuous

When this input is activated, it indicates that ground breaker is open.

CBE activate AVR one

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●					●					Continuous

When this input is activated, the generator controller is informed by the group controller to activate close before excitation. (Redundant of CBE AVR two).

NOTE This function is option-dependent. Option G7 is required.

CBE activate AVR two

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●					●					Continuous

When this input is activated, the generator controller is informed by the group controller to activate close before excitation. (Redundant of CBE AVR one).

NOTE This function is option-dependent. Option G7 is required.

MB pos. feedback OFF

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●				●	●				Continuous

When this input is activated, the application can continue to run even though there is a problem with the position feedback from a mains breaker.

NOTICE

Use this function at your own risk

Analyse the application to know the risks that arise when the controllers do not have the mains breaker position feedback.

PMS block input [1 or 2]

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●					●					Continuous

When these inputs are activated, they activate the timers defined in parameters 8861 and 8862.

More information
See **PMS blocking** in **Option G5 Power management**.

Allow safe regeneration

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●	●	●	●	●	●					Continuous

This input is an additional condition to meet before the controller can activate the safe regeneration EIC output. It can be used if fans, heaters, and so on, are connected before the generator breaker closes. This input corresponds to the M-Logic command `EIC commands > EIC Allow safe regeneration`.

More information
See **Option H12 H13 Engine communication AGC-4 Mk II**.

PLC control start (PMS lite)

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●					●					Pulse

This input is for a PMS lite application running in PLC start/stop mode. The input starts a PLC-controlled genset.

PLC control stop (PMS lite)

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●					●					Pulse

This input is for a PMS lite application running in PLC start/stop mode. The input stops a PLC-controlled genset.

PLC control start/stop (PMS lite)

Auto	Semi	Test	Man	Block	DG	Mains	BTB	Group	Plant	Input type
●					●					Continuous

This input is for a PMS lite application. When this input is activated in a controller, the controller actives PLC start/stop mode.

11.2 Multi-inputs

The standard controller has three multi-inputs. In addition, option M15 has four 4-20 mA inputs, and option M16 has four multi-inputs.

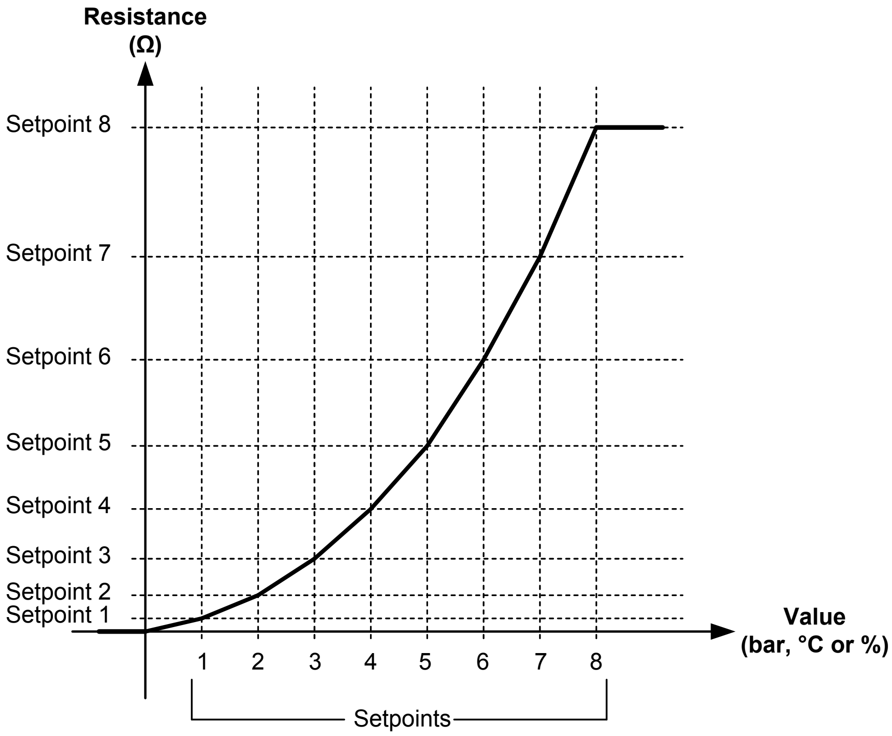
The analogue inputs can be configured in the utility software, on the *I/O setup* page.

How to configure a multi-input on AGC-4 Mk II
See our tutorial on How to configure a multi-input on AGC-4 Mk II for help and guidance.

Input type	Standard	Option M15	Option M16	Notes
4 to 20 mA	●	●	●	On the *I/O setup* page, configure a curve for the 4 to 20 mA input. Use *Scaling* to show the curve output with the selected decimal places on the display unit. For **No unit 1/10**, one decimal place is shown. For **No unit 1/100**, two decimal places are shown.
0 to 40 V DC	●			The 0 to 40 V DC input has primarily been designed to handle the battery asymmetry test.
0 to 5 V DC			●	
Pt100	●			The controller uses the standard Pt100 curve. You can use the *Engineering units* parameter to change the units from **°C** to **°F**.
Pt1000	●		●	The controller uses the standard Pt1000 curve. You can use the *Engineering units* parameter to change the units from **°C** to **°F**.
RMI oil pressure	●			Use *RMI type* to select one of the standard curves or a configurable curve. You can use the *Engineering units* parameter to change the units from **bar** to **psi**. If the RMI input is used as a level switch, then be aware that voltage must not be connected to the input. If any voltage is applied to the RMI input, it will be damaged. See the **Application Notes** for more wiring information.
RMI water temperature	●			Use *RMI type* to select one of the standard curves or a configurable curve. You can use the *Engineering units* parameter to change the units from **°C** to **°F**. If the RMI input is used as a level switch, then be aware that voltage must not be connected to the input. If any voltage is applied to the

Input type	Standard	Option M15	Option M16	Notes
				RMI input, it will be damaged. See the **Application Notes** for more wiring information.
RMI fuel level	●			Use *RMI type* to select one of the standard curves or a configurable curve. If the RMI input is used as a level switch, then be aware that voltage must not be connected to the input. If any voltage is applied to the RMI input, it will be damaged. See the **Application Notes** for more wiring information.
Digital	●			If the input type is **Binary**, you can select a digital input function for the multi-input.

Configurable RMI curve example



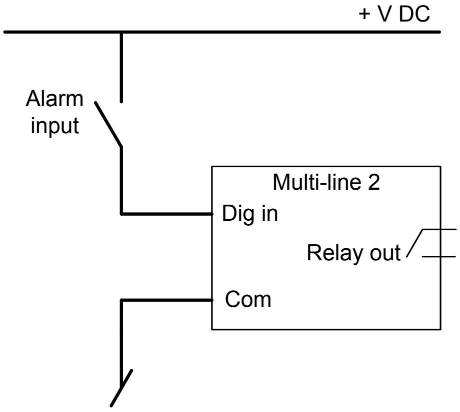
11.3 Input function selection

Digital input alarms can be configured with a possibility to select when the alarms are to be activated. The possible selections of the input function are normally open or normally closed.

The drawing below illustrates a digital input used as an alarm input:

1. Digital input alarm configured to NC, normally closed. This will initiate an alarm when the signal on the digital input disappears.
2. Digital input alarm configured to NO, normally open. This will initiate an alarm when the signal on the digital input appears.

NOTE The relay output function can be selected to be ND (Normally De-energised), NE (Normally Energised), M-Logic / Limit relay, Horn or Siren.



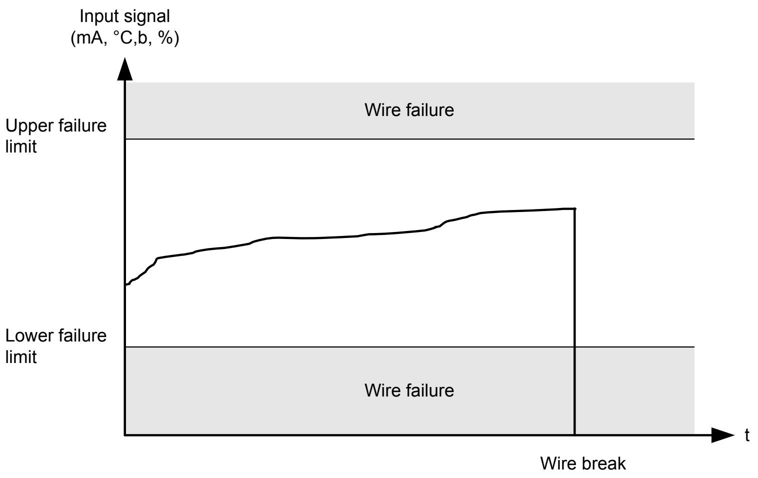
11.4 Wire fail detection

If it is necessary to supervise the sensors/wires connected to the multi-inputs and analogue inputs, then it is possible to enable the wire break function for each input. If the measured value on the input is outside the normal dynamic area of the input, it will be detected as if the wire has made a short circuit or a break. An alarm with a configurable fail class will be activated.

Input	Wire failure area	Normal range	Wire failure area
4-20 mA	< 3mA	4-20 mA	> 21 mA
0-40V DC	≤ 0V DC	-	N/A
RMI Oil, type 1	< 1.0 ohm	-	> 195.0 ohm
RMI Oil, type 2	< 1.0 ohm	-	> 195.0 ohm
RMI Temp, type 1	< 4.0 ohm	-	> 488.0 ohm
RMI Temp, type 2	< 4.0 ohm	-	> 488.0 ohm
RMI Temp, type 3	< 0.6 ohm	-	> 97.0 ohm
RMI Fuel, type 1	< 0.6 ohm	-	> 97.0 ohm
RMI Fuel, type 2	< 1.0 ohm	-	> 195.0 ohm
RMI configurable	< lowest resistance	-	> highest resistance
P100	< 82.3 ohm	-	> 194.1 ohm
P1000	< 823 ohm	-	> 1941 ohm
Level switch	Only active if the switch is open		

Principle

The illustration below shows that when the wire of the input breaks, the measured value will drop to zero. Then the alarm will occur.



MPU wire break (menu 4550)

The MPU wire break function is only active when the genset is not running. In this case an alarm will be raised if the wire connection between the AGC and MPU breaks.

Stop coil wire break (menu 6270)

The alarm will occur when the stop coil is not activated (generator is running) and the input is deenergised.

11.5 External analogue set points

The genset can be controlled from external set points. The external analogue set point inputs are only available if hardware option M12 is selected. A digital input must be used to activate each external set point.

Five inputs can be selected using the PC utility software (USW):

Input	Ext. set point active condition*
Ext. frequency ctrl	Stand-alone generator or GB opened
Ext. power ctrl	Parallel to mains
Ext. voltage ctrl	Stand-alone generator or GB opened
Ext. PF ctrl	Parallel to mains
Ext. VAr ctrl	Parallel to mains

NOTE * The controller set points are ignored if the condition is not present. For example, it is not possible to use the frequency controller when paralleling to the mains.

The table below shows the set points that are possible for external analogue inputs.

Controller	Input voltage	Description	Comment
Frequency	+/-10 V DC	f_{NOM} +/-10 %	Active when MB is OFF
Power	+/-10 V DC	P_{NOM} +/-100 %	
Voltage	+/-10 V DC	U_{NOM} +/-10 %	Active when GB is OFF
Reactive power	+/-10 V DC	Q_{NOM} +/-100 %	
Power factor	÷10 V...0...10 V DC	0.6 capacitive...1.0...0.6 inductive	

The external set points can be used in all genset modes, when auto or semi-auto mode is selected.

NOTE The standard genset controller has a limited number of digital inputs. To have all the required the digital inputs, the controller may need additional hardware options.

11.5.1 External analogue set point terminals

Terminal	Function	Technical data	Description
40	-10/+10 V DC	Analogue input	f/P set point
41	Com.	Common	Common
42	-10/+10 V DC	Analogue input	U/Q set point

11.5.2 Other sources of external analogue set points

The AGC does not require hardware option M12 (and digital inputs for set point activation) if it uses these other sources of external analogue set points.

External analogue set points using Modbus

The external analogue set points can be sent over Modbus.

More information
See **Option H2 and H9 Modbus communication** and the AGC **Modbus tables** for more information.

External analogue set points using CIOs

External analogue set points can come from a CIO. Use M-Logic to activate the set point(s).

More information
See **CIO 308 Installation and commissioning guide** and **Option A10** for more information.

How to configure a CIO on AGC-4
See our tutorial on How to configure a CIO on AGC-4 for help and guidance.

RRCR external set point control

The grid can use a Radio Ripple Control Receiver (RRCR) for load management.

More information
See **Additional Functions, RRCR external set point control** in the **Designer's Handbook** for more information.

11.6 Outputs

The controller has a number of output functions which can be configured to any available relay.

Output function	Auto	Semi	Test	Man	Block	Configurable	Output type
Trip NEL 1	●	●	●	●	●	Configurable	Pulse
Trip NEL 2	●	●	●	●	●	Configurable	Pulse
Trip NEL 3	●	●	●	●	●	Configurable	Pulse

11.6.1 Function description

- **Trip NEL 1**: This output is used to trip load groups.
- **Trip NEL 2**: This output is used to trip load groups.
- **Trip NEL 3**: This output is used to trip load groups.

NOTE For more information, see Trip of NEL.

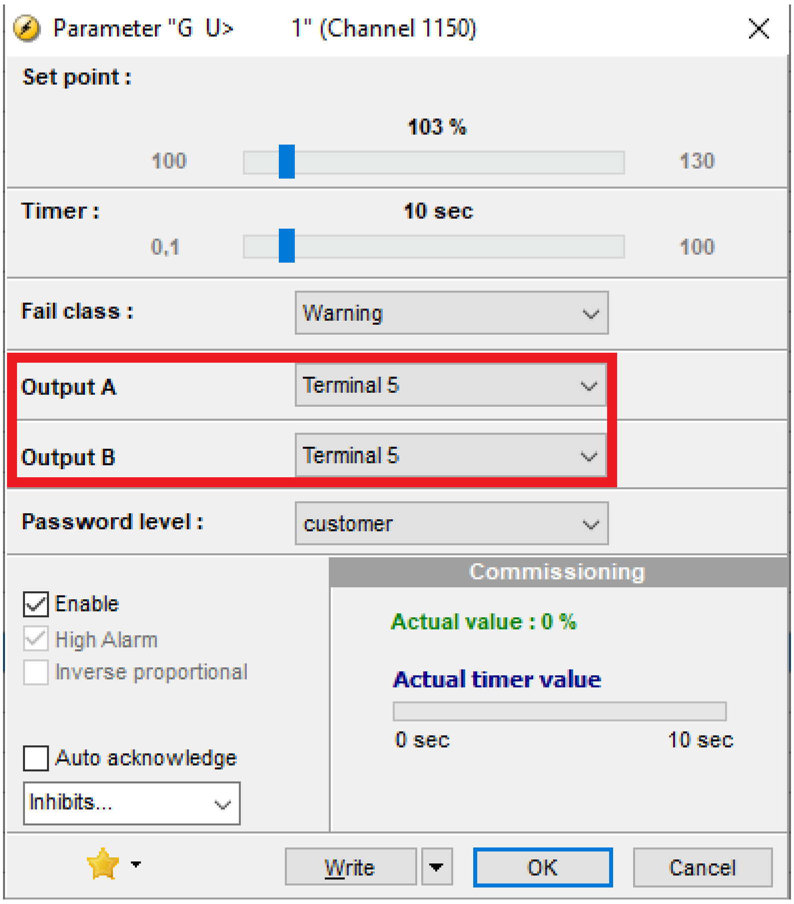
11.7 Limit relay

For all alarm functions, you can activate one or two output relays as shown below. The following explains how to use an alarm function to activate an output without activating an alarm. ON and OFF delay timers are described too.

If no alarm is needed, it is possible to do one of the following things:

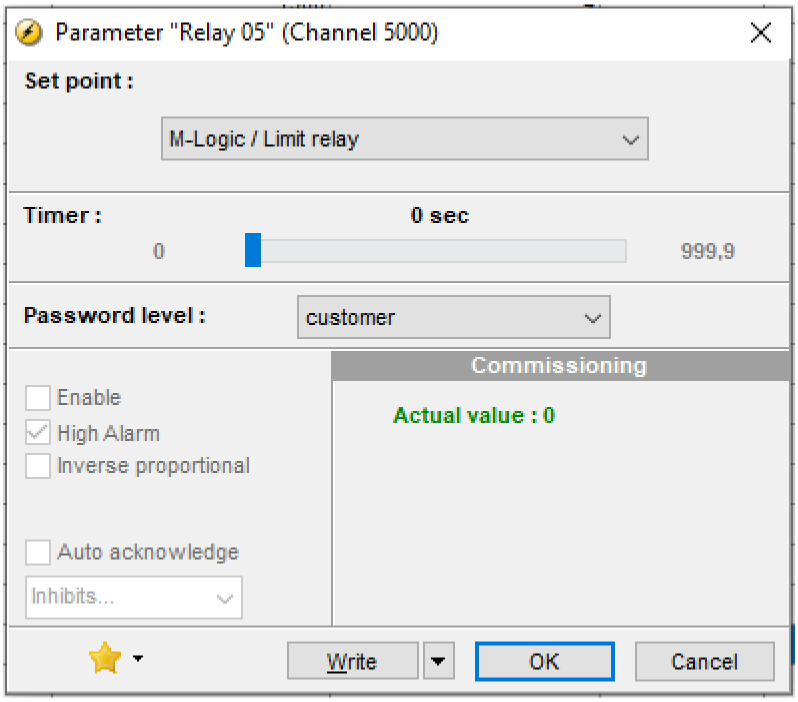
- Set both output A and output B to **Limits**.
- Set both output A and output B to the same terminal. If terminal alarm is not required, the alarm function in the specified relay is set to *M-Logic / Limit relay*.

In the example below, the relay closes when the generator voltage is above 103 % for 10 seconds, and no alarm is activated because both output A and output B are configured to relay 5, which is configured as *M-Logic / Limit relay*.

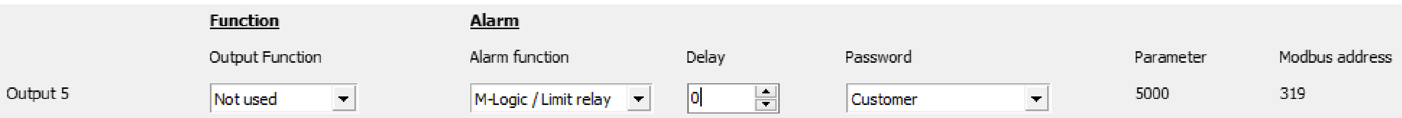


The timer configured in the alarm window is an ON delay that determines the time during which the alarm conditions must be met before activation of any alarms or outputs.

When a relay is selected (relay on terminal 5 in this example), it must be set up as a limit relay as shown below, otherwise an alarm indication will still appear.



Alternatively, you can configure the relay in the USW under *I/O Setup*:

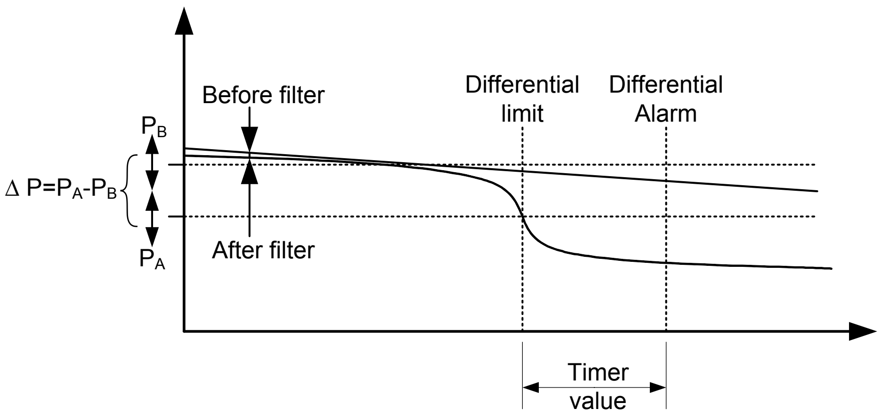


The timer in the image above is an OFF delay, meaning that when the alarm level is OK again, the relay will remain activated until the timer runs out. The timer is only effective when it is configured as *M-Logic / Limit relay*. If it is configured to any *Alarm relay*, the relay is deactivated when the alarm conditions disappear and the alarm is acknowledged.

11.8 Differential measurement

With the differential measurement function, the AGC can compare two analogue inputs. You can configure an alarm and/or relay to activate when the difference exceeds the configured set point.

For example, for an air filter check, the timer is activated if the set point (the difference between PA (analogue A) and PB (analogue B)) is exceeded. Note that if the differential value drops below the set point before the timer runs out, then the timer is stopped and reset.



Nine different differential measurements between two analogue input values can be configured. Differential measurements between two sensors can be configured in menus 4600-4606, 4670-4676 and 4741-4746.

Selection for the differential measurement inputs

Parameter	Name	Range	Default
4601	Delta ana1 InpA	See below.	Multi input 102
4602	Delta ana1 InpB	See below.	Multi input 102

A wide range of inputs are possible (depending on the controller options). See the selections for these parameters in the utility software. Alternatively, these are listed in **Differential measurement** in the **Parameter list**.

Using differential measurement to create an extra analogue alarm

If the same measurement is selected for input A and input B, the controller uses the value of the input for the differential measurement alarm.

Configuring the differential alarm

The relevant alarm set point is chosen in parameters 4610-4660, 4680-4730 and 4750-4800. Each alarm can be configured in two alarm levels for each differential measurement between analogue input A and input B. The screenshot below shows the parameters to configure an alarm for differential measurement 1.