AGC 4 Steam Hand Book

Advanced Genset Controller, AGC-4

- Synchronisation of Steam Turbines
- Load Sharing
- Grid synchronisation
- Base loading
- Import/Export control
- SW emulation of application

1. About AGC 4

Market-leading all-round controller

DEIF's Advanced Genset Controller (AGC-4) is the most comprehensive and flexible power management and protection unit on the market today. A further development of DEIF's AGC-3, the new generation controller is fully compatible with its predecessor and has been designed to allow for easy, intuitive, and smooth switch-overs for those looking to upgrade.

Suitable for a wide range of applications, the AGC-4's standard sequences include back-up power, synchronisation, and load sharing.

The AGC-4 is simple to incorporate into both new and existing designs, customizing the application to fit your needs, for instance dedicating specific functions or logic conditions to different inputs and outputs.

Technologically sophisticated, the AGC-4 is also the world's most robust power management controller, successfully tested to maintain reliability and durability in extreme weather and hazardous conditions. Approvals include TÜV and UL.

Innovative plant management

Solutions

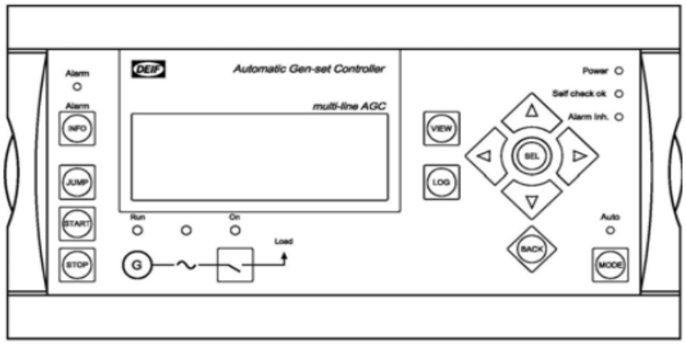
Responding to a growing market demand for temporary and emergency plants to provide support in cases of seasonal change, for remote locations with limited access to distribution, or disaster relief, DEIF has successfully developed a groundbreaking plant management solution that can handle up to 16 turbines in one application.

Lifting turbine control from single units to plant level, enabling advanced control and protection for large setups from one central point of intelligence, AGC Plant Management incorporates plant power factor control at connection points, scaling, load profile priorities routines and more.

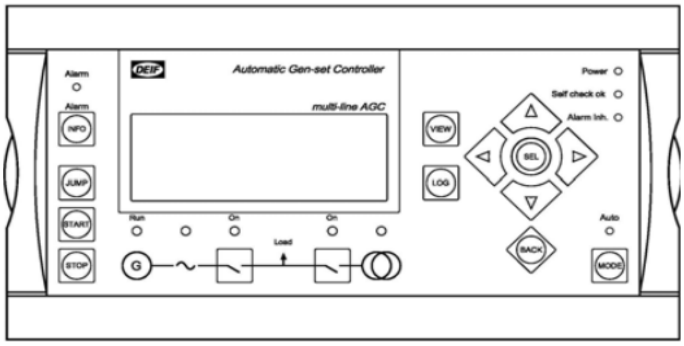
The innovative system uses the plant's generators to black-start large step-up transformers with the push of a button: enter the power setpoint you need and let the AGC-4 controllers do the rest.

Tried and tested at locations in Africa, Asia, and South America over the past three years, AGC-4 Plant Management Solutions have been developed not just with an eye for safety but for fuel saving and optimized maintenance intervals, introducing island, fixed power mode, and asymmetrical load sharing designs to cut running costs.

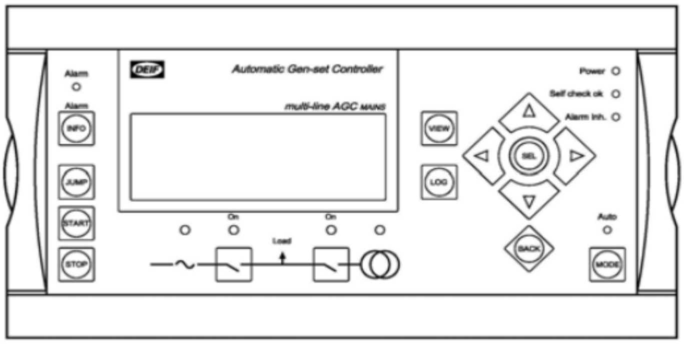
2. Display Options



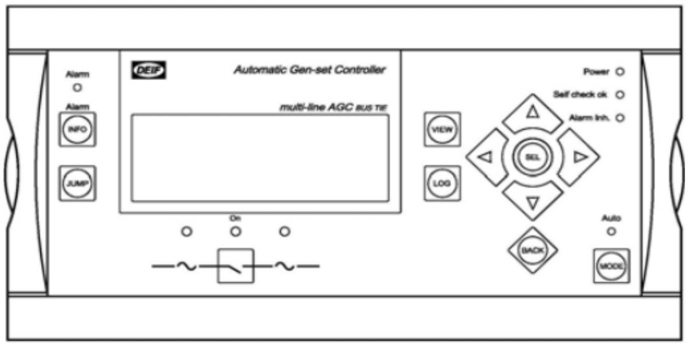
Turbine breaker control (Island)
(Option Y1)



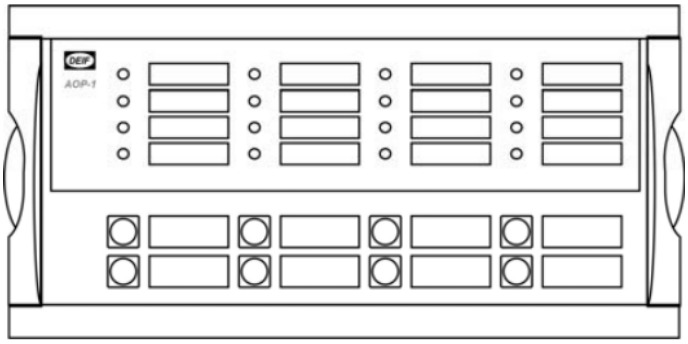
Turbine breaker and mains breaker control
(Option Y3)



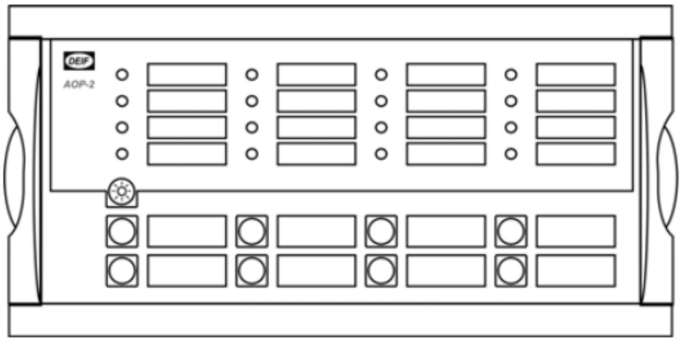
Tie breaker and mains breaker control
(Option Y4)



Bus tie breaker control
(Option Y5)

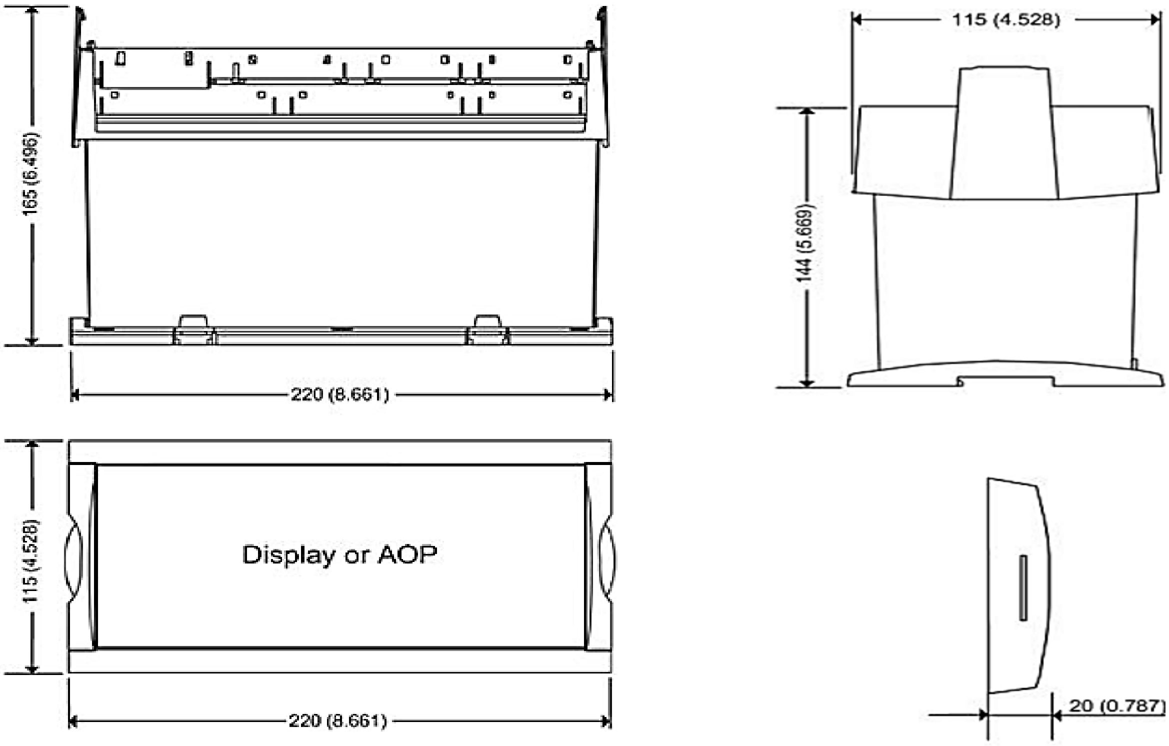


Additional operator's panel - AOP-1
(Option X3)

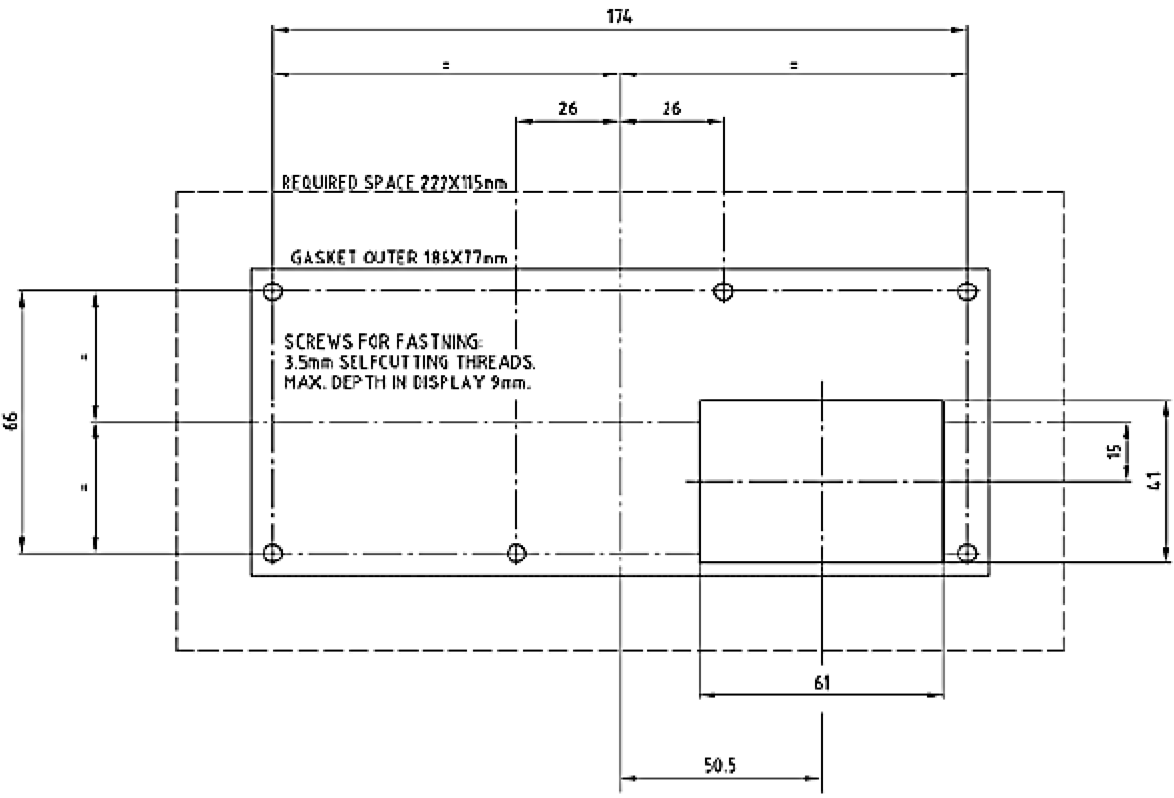


Additional operator's panel - AOP-2
(Option X4)

3. Unit Dimensions



Dimensions are given in mm



4. Description of Hardware & Options

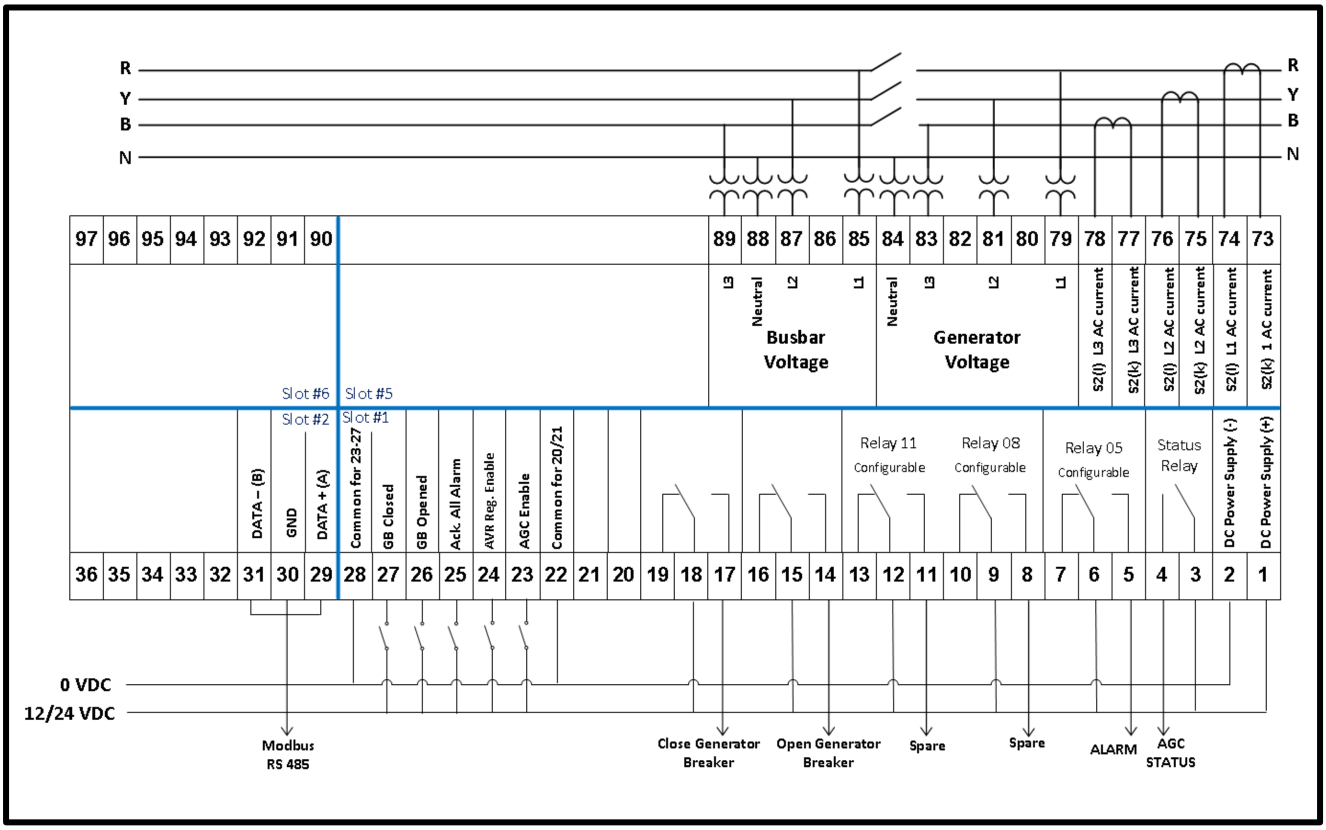
Slot	Terminal	Description	Option Available	Available in AGC 4 Steam
#1	1-28	Power Supply	8-36V DC supply, 11W 1 x status output relay 5 x relay outputs 2 x pulse outputs (kWh, kVArh) 5 x digital inputs	**Standard**
#2	29-36	Communication	**H2:** Modbus RTU (RS485) **H3:** Profibus DP **H8.2:** Ext. I/O modules	**H2:** Modbus RTU (RS485) **(as standard)**
#3	37-64	In-/outputs/load sharing	**M12:** 13 x digital inputs 4 x relay outputs **G3:** Active power load sharing Reactive power load sharing (requires D1)	**Optional**
#4	65-72	Governor, AVR, in-/outputs	**M14.4:** 4 x relay (standard) **E1:** 2 x +/-20mA out **E2:** 2 x 0(4)...20mA out **EF2:** 1 x +/-20mA out 1 x 0(4)...20mA out **EF4:** 1 x +/-20mA out 2 x relay **EF5:** 1 x +/-20mA out 1 x PWM out 2 x relay	**M14.4:** 4 x relay **(as standard)**
#5	73-89	AC measuring	3 x turbine voltage 3 x turbine current 3 x busbar/mains voltage	**Standard**
#6	90-97	In-/outputs	**F1:** 2 x 0(4)...20mA out, transducer **M13.6:** 7 x digital inputs **M14.6:** 4 x relay outputs **M15.6:** 4 x 4...20mA inputs	**Optional**
#7	98-125	Engine I/F (std.)	8-36V DC supply, 5W 1 x magnetic pick-up (MPU) 3 x multi-inputs 7 x digital inputs 4 x relay outputs	**Standard**
#8	126-133	Engine comm., in-/outputs	**H5:** J1939 (option H7) **H6:** Cummins GCS **H8.8:** Ext. I/O modules **M13.8:** 7 x digital inputs **M14.8:** 4 x relay outputs **M15.8:** 4 x 4...20mA inputs	**Optional**

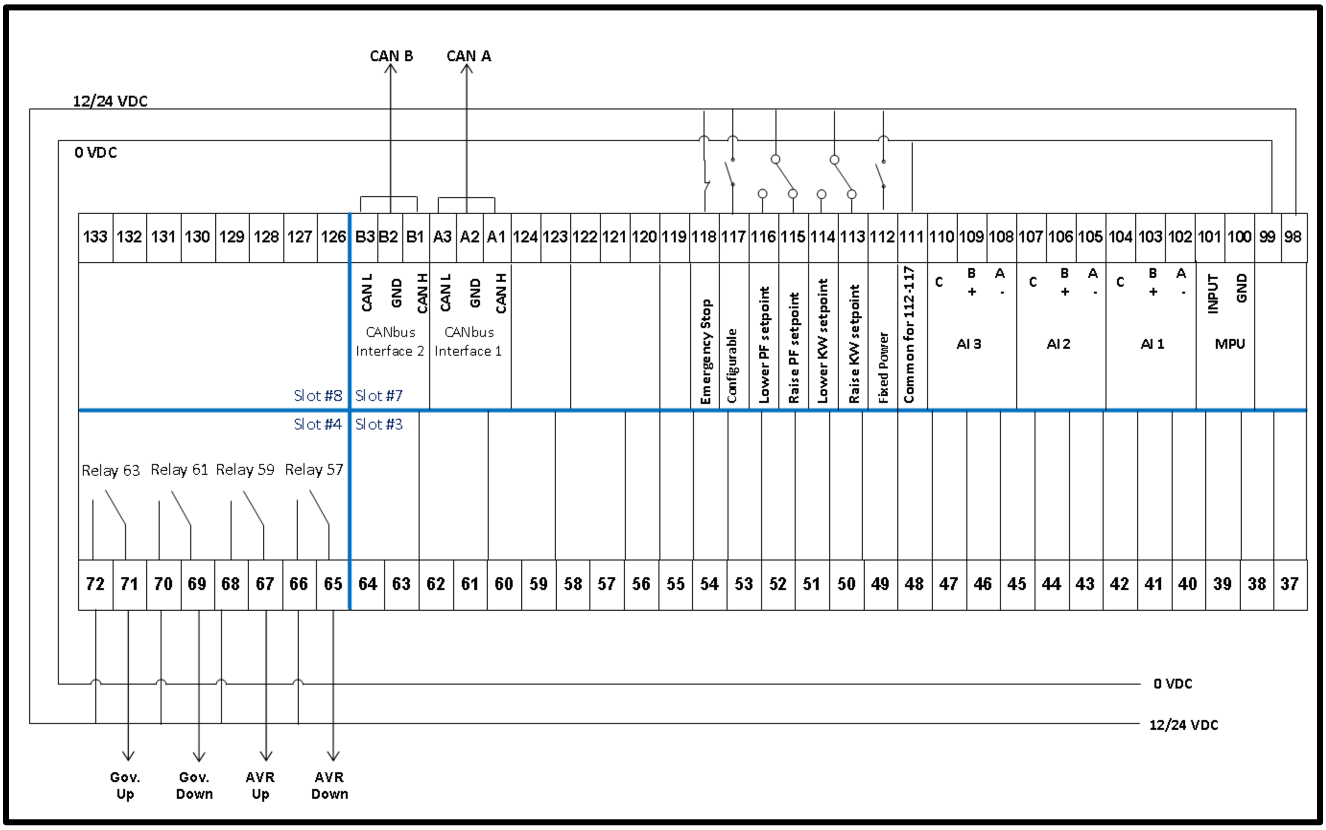
5. Description of Software Options

Option	Description	Available in AGC 4 Steam
A1	Time-dependent undervoltage (27t) Undervoltage and reactive power lov (27Q) Vector jump (78) df/dt (ROCOF) (81)	Standard
A4	Positive sequence (mains voltage low) (27)	Optional
A5	Directional overcurrent (67)	Optional
C2	Negative sequence voltage high (47) Negative sequence current high (46) Zero sequence voltage high (59) Zero sequence current high (50)	Optional
D1	Constant voltage control (stand-alone) Constant reactive power control (parallel with mains) Constant power factor control (parallel with mains) Reactive load sharing (island paralleling with other generators)	Standard
G3	Load sharing with analogue lines	Optional
G4	Power management, 16 gen-sets, 8 bus tie breakers	If M12 is present, G3 is a software option
G5	Power management, 16 mains, 16 gen-sets, 8 bus tie breakers	
H	Serial communication	H2 as Standard
M12	13 binary inputs, 4 relay outputs, configurable	If G3 is present, M12 is a software option

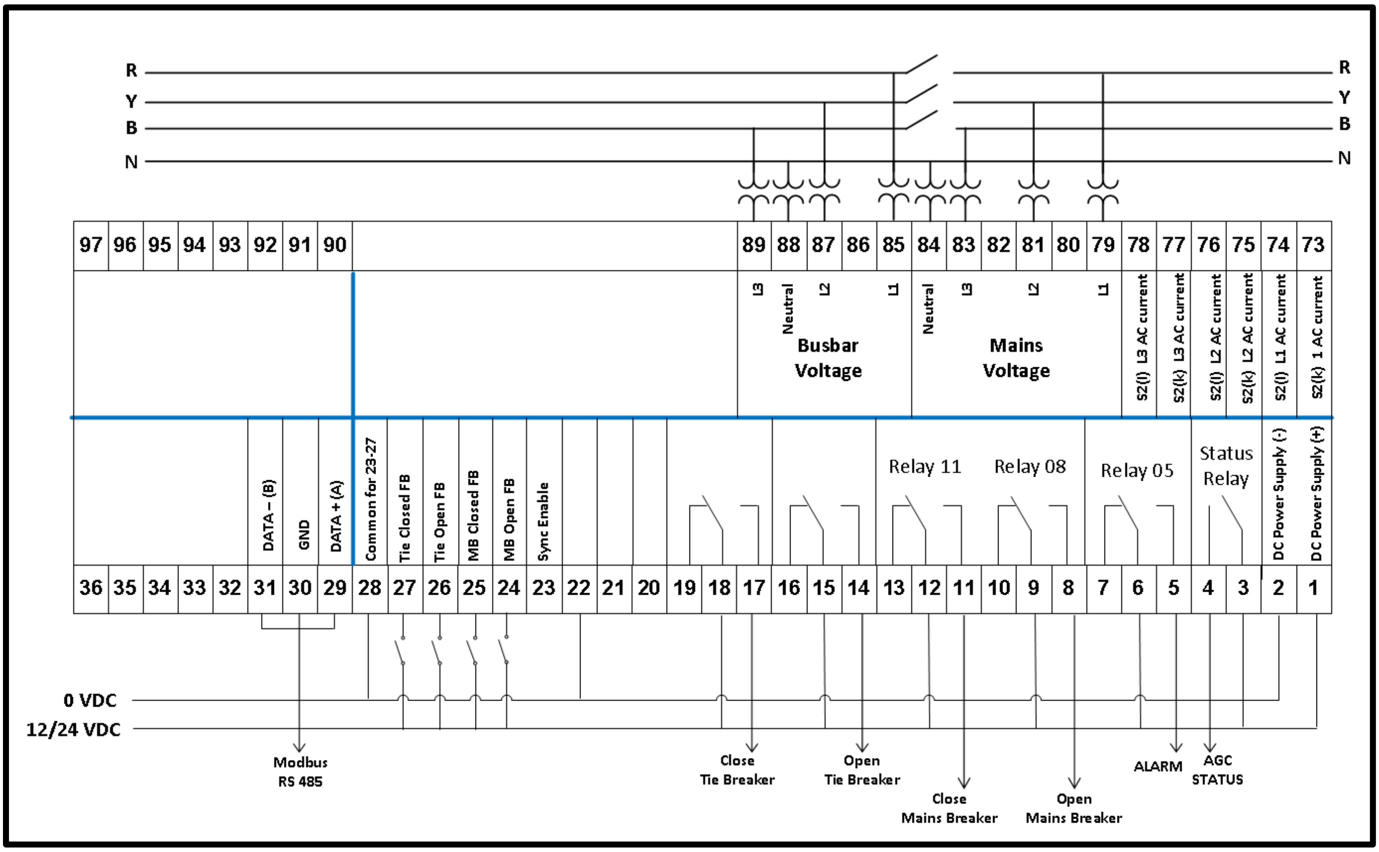
6. Drawings

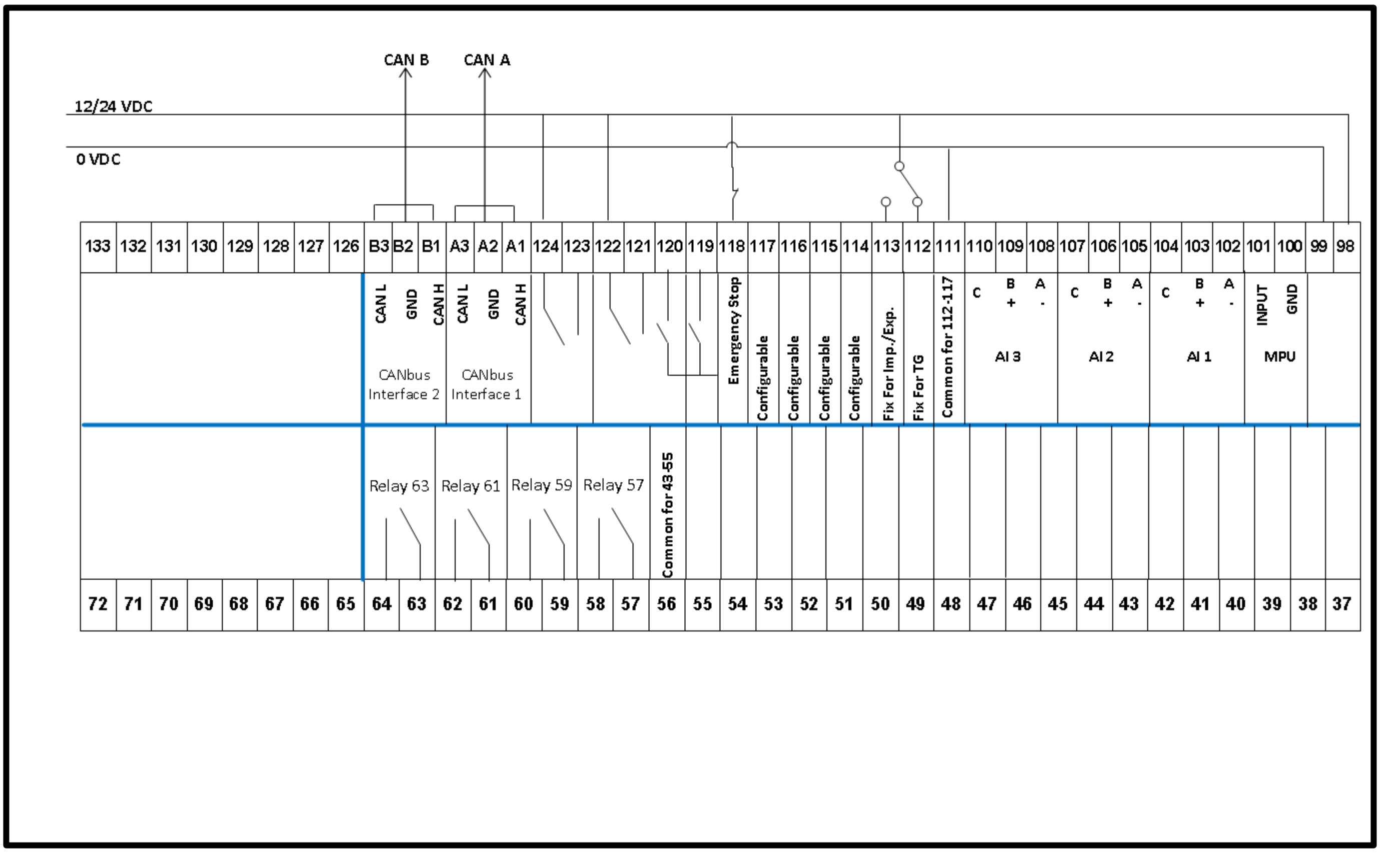
6.1 AGC 4 GEN



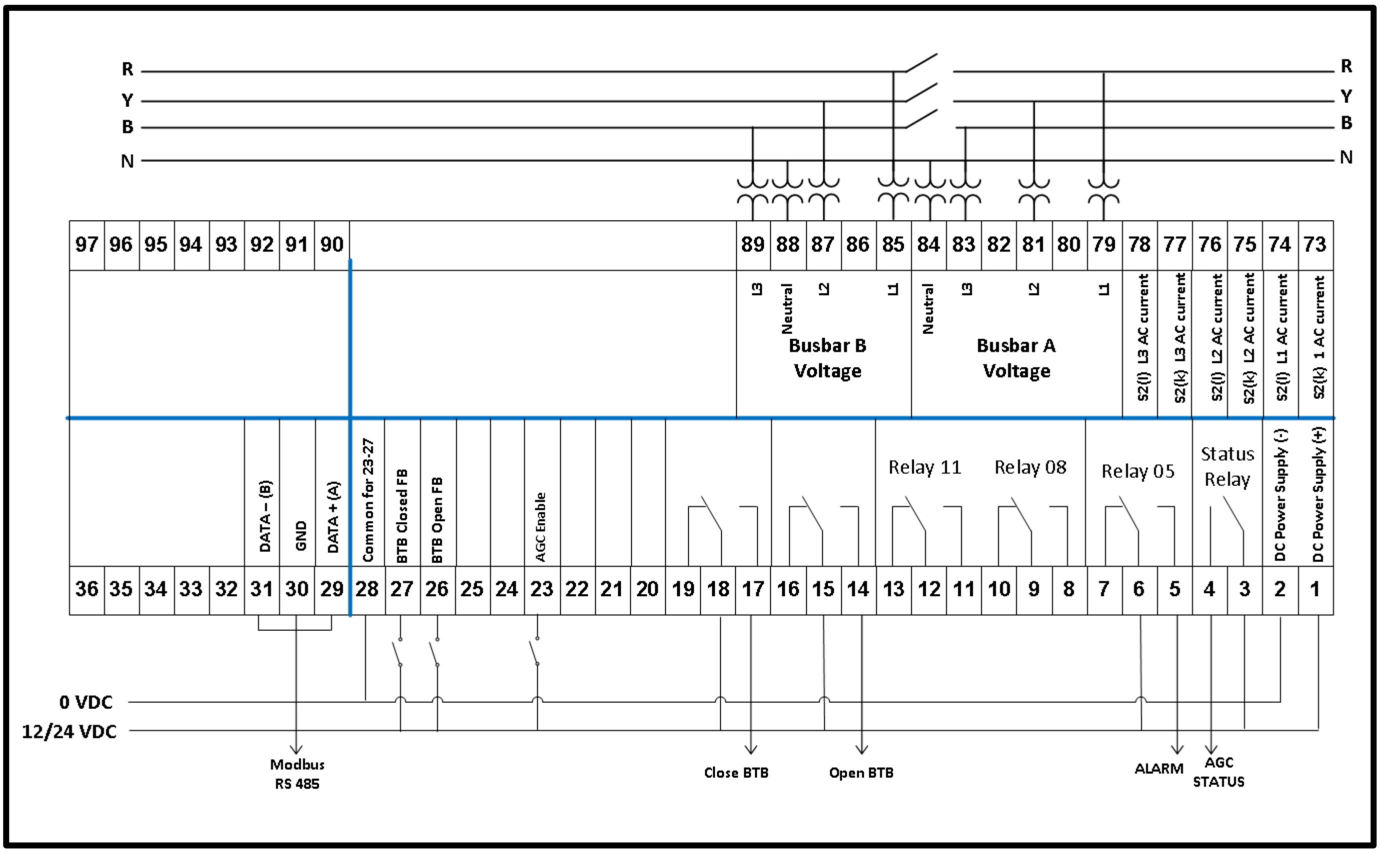


6.2 AGC 4 Mains

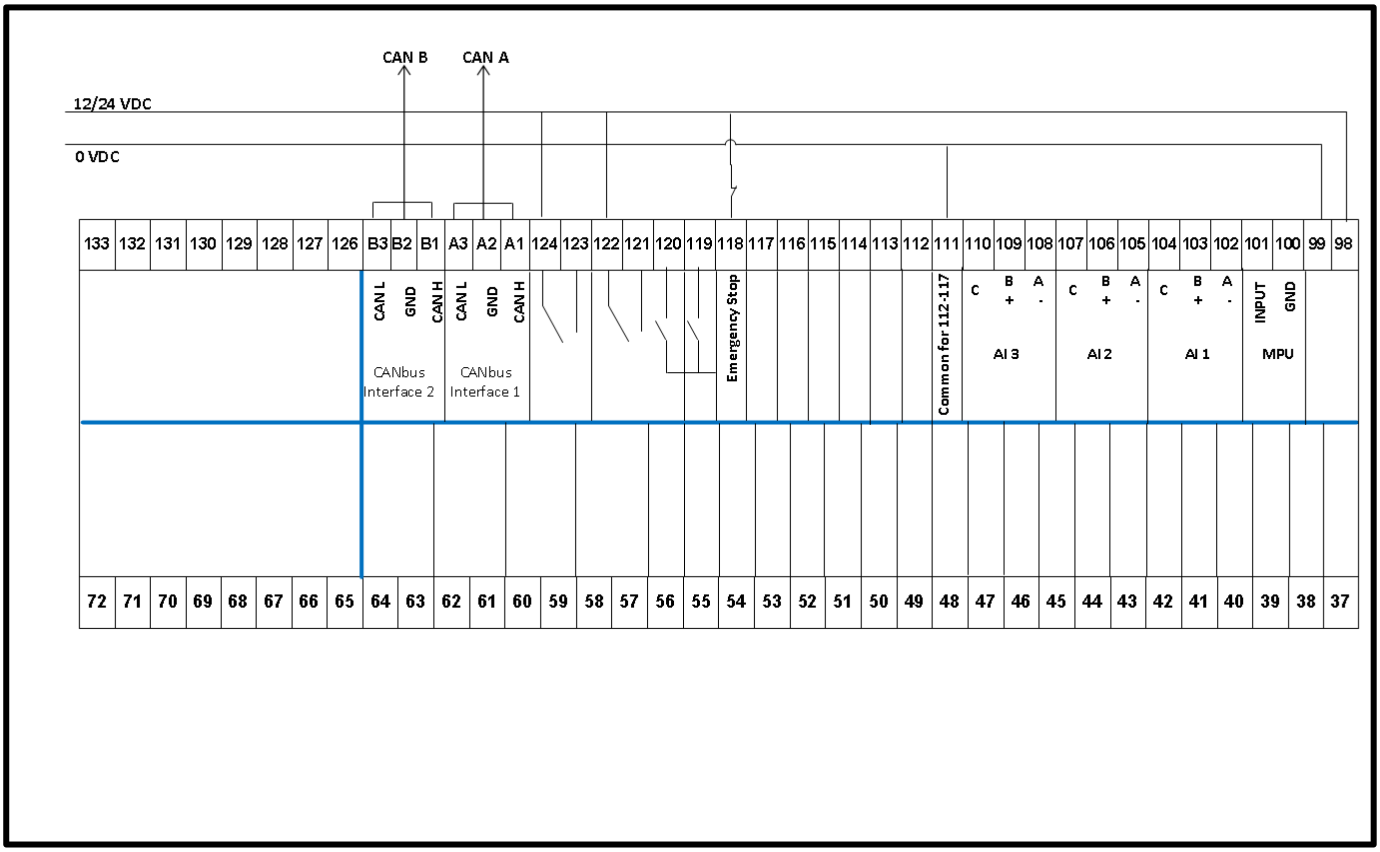




6.3 AGC 4 BTB



R
Y
B
N
97 96 95 94 93 92 91 90
89 88 87 86 85 84 83 82 81 80 79 78 77 76 75 74 73
L3 Neutral L2 L1
Busbar B Voltage
Neutral L3 L2 L1
Busbar A Voltage
S2(l) L3 AC current
S2(k) L3 AC current
S2(l) L2 AC current
S2(k) L2 AC current
S2(l) L1 AC current
S2(k) 1 AC current
DATA – (B)
GND
DATA + (A)
Common for 23-27
BTB Closed FB
BTB Open FB
AGC Enable
Relay 11
Relay 08
Relay 05
Status Relay
DC Power Supply (-)
DC Power Supply (+)
36 35 34 33 32 31 30 29 28 27 26 25 24 23 22 21 20 19 18 17 16 15 14 13 12 11 10 9 8 7 6 5 4 3 2 1
0 VDC
12/24 VDC
Modbus RS 485
Close BTB
Open BTB
ALARM
AGC STATUS



CAN B
CAN A
12/24 VDC
0 VDC
133 132 131 130 129 128 127 126 B3 B2 B1 A3 A2 A1 124 123 122 121 120 119 118 117 116 115 114 113 112 111 110 109 108 107 106 105 104 103 102 101 100 99 98
CAN L
GND
CAN H
CANbus Interface 2
CANbus Interface 1
Emergency Stop
Common for 112-117
C B A + -
AI 3
AI 2
AI 1
INPUT
GND
MPU
72 71 70 69 68 67 66 65 64 63 62 61 60 59 58 57 56 55 54 53 52 51 50 49 48 47 46 45 44 43 42 41 40 39 38 37

6.4 Option M12 Detail

Option M12 is a Hardware option used for extra digital Input Outputs or Analog setpoint (+/-10VDC) is to be given or Analog Load sharing is to be used.

Term.	Function	Technical data	Description
37	Used for the Option G3		
38			
39			
40	-10…0…10V DC	Analogue I/O	f/P setpoint
41	Com.	Common	Common
42	-10…0…10V DC	Analogue I/O	U/Q setpoint
43	Digital input 43	Optocoupler	Configurable
44	Digital input 44	Optocoupler	Configurable
45	Digital input 45	Optocoupler	Configurable
46	Digital input 46	Optocoupler	Configurable
47	Digital input 47	Optocoupler	Configurable
48	Digital input 48	Optocoupler	Configurable
49	Digital input 49	Optocoupler	Configurable
50	Digital input 50	Optocoupler	Configurable
51	Digital input 51	Optocoupler	Configurable
52	Digital input 52	Optocoupler	Configurable
53	Digital input 53	Optocoupler	Configurable
54	Digital input 54	Optocoupler	Configurable
55	Digital input 55	Optocoupler	Configurable
56	Com.	Common	Common for terminals 43 to 55
57	NO	Relay 57	Configurable
58	Com.	250V AC/5A	
59	NO	Relay 59	Configurable
60	Com.	250V AC/5A	
61	NO	Relay 61	Configurable
62	Com.	250V AC/5A	
63	NO	Relay 63	Configurable
64	Com.	250V AC/5A	

G3 is software option used if Analog load sharing is required

Term.	Function	Technical data	Description	Comment
37	-5/+5V DC	Analogue I/O	Active load sharing line	Requires option G3
38	Com.	Common	Common	
39	-5/+5V DC	Analogue I/O	Reactive load sharing	Requires option D1/G3
40	-10/+10V DC	Analogue I/O	f/P set point	Requires option G3
41	Com.	Common	Common	
42	-10/+10V DC	Analogue I/O	U/Q set point	Requires option D1/G3

6.5 Option E1 Detail

E1 is hardware option used if governor or AVR interface is analog.

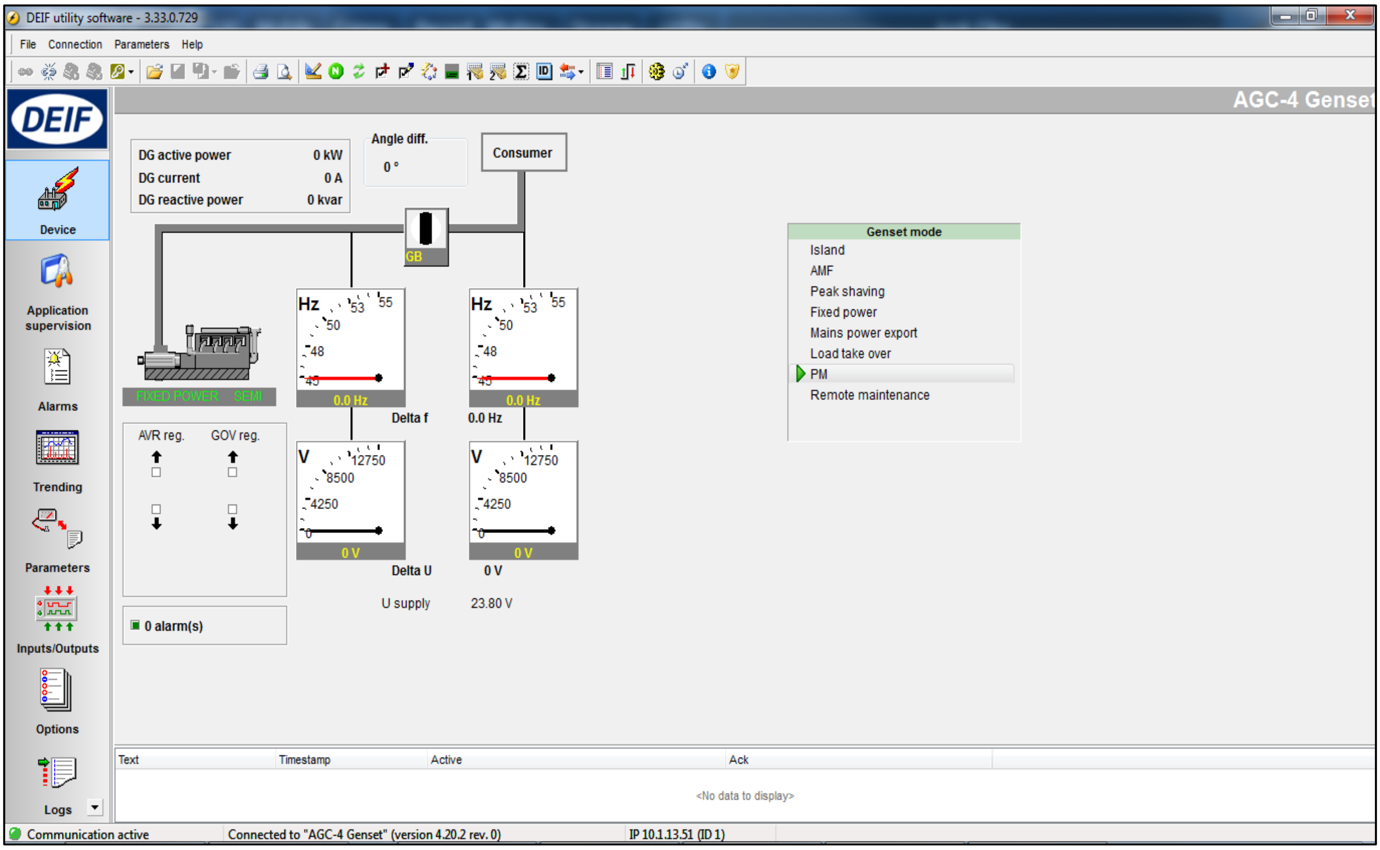
Term.	Function	Description
65	Not used	
66	+/-25mA out	Speed governor, AVR or transducer output 66
67	0	
68	Not used	
69	Not used	
70	+/-25mA out	Speed governor, AVR or transducer output 71
71	0	
72	Not used	

7. Description of Inputs & Outputs

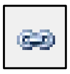
Digital Inputs	
AGC Enable	Deactivation of the input stops the governor & AVR Regulation but the protection will remain in line.
AVR Reg. Enable	Deactivation of the input stops the AVR Regulation but the protection will remain in line.
Ack. All alarms	Activation of the input Acknowledge all alarms.
GB Opened	Turbine breaker open feedback.
GB Closed	Turbine breaker close feedback.
Fixed Power	Activation of the input forces the Genset mode to fixed power set point.
Raise Power set point	Activation of the input raises the set point of the power (KW).
Lower Power set point	Activation of the input lowers the set point of the power (KW).
Raise PF set point	Activation of the input raises the set point of the power factor (P.F.).
Lower PF set point	Activation of the input lowers the set point of the power factor (P.F.).
Configurable	This input is configurable

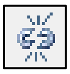
Digital Outputs	
Status Relay	Relay gets deactivates if AGC fails.
Alarm Relay	Relay activates if alarm if any fail class generates e.g. (Warning /Trip GB)
Close TG Breaker (Sync.)	Relay activates to close the breaker on dead bus or synchronisation
Open TG Breaker	Relay activates when the open command given to AGC or fail class trip GB generates
Gov. Up	Relay activates when the Governor regulator requires to raise the actuator
Gov. Down	Relay activates when the Governor regulator requires to lower the actuator
AVR Up	Relay activates when the AVR regulator requires to raise the actuator
AVR Down	Relay activates when the AVR regulator requires to lower the actuator
Configurable	This output is configurable

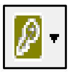
8. Utility Software



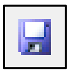
Button Description used in Utility Software

 This button is used to connect the device & go online

 This button is used to disconnect the device & go offline

 This button is used to change the user level

 Activating this button makes it possible to open a previously saved logics file.

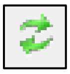
 This button is used to save online the parameter, configuration, log, m-logic, translation to file (part of the general Multi-line 2 configuration file ".USW").

 This button is used to export the parameter to text, Excel or PDF file,

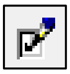
 This button is used the print the file.

 This button is used to open the setting for communication of device & Utility Software

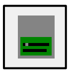
 This button is used to open the N- option configurator so as to view/ change IP address

 This button is used to open Modbus configurator

 This button is used to upgrade options of the controller

 This button is used to write new options of the controller

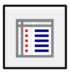
 This button is used to write the firmware to device

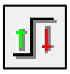
 This button is used to configure the view/display of the device

 This button is used to configure AOP 1 (Additional Operator Panel - 1)

 This button is used to configure AOP 1 (Additional Operator Panel - 2)

 This button is used to batch read & write of parameter, configuration, log, m-logic, translation to file (part of the general Multi-line 2 configuration file ".USW").

 This button is used to show/hide the real time reading window

 This button is used to configure the input output settings

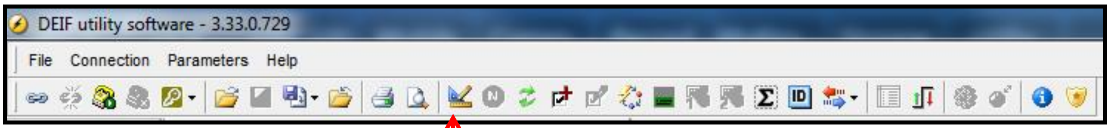
 This button is used to synchronise the PC clock to controller

 This button is used to see the detail of Utility software

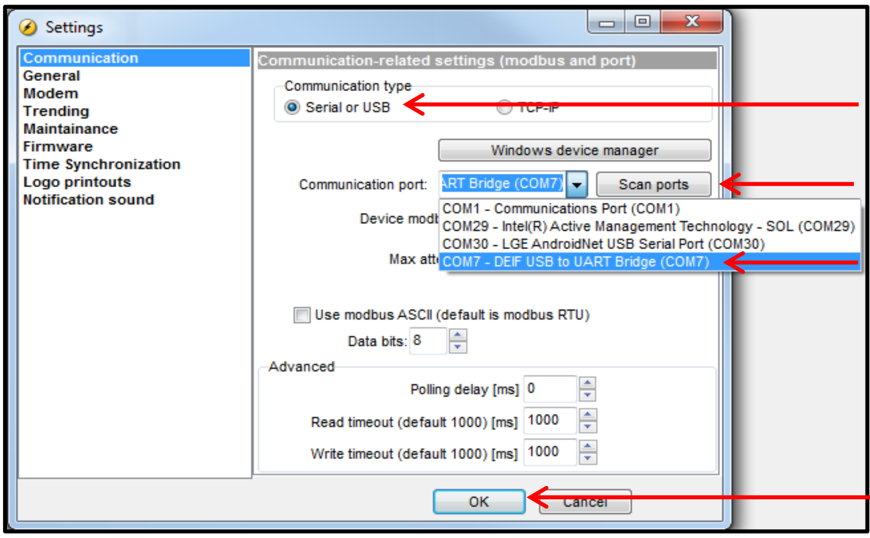
 This button is used to set permission to user levels

8.1 Getting started with DEIF utility software (USW)

Click on the icon on desk top or in Start menu icon:



Open the application settings by clicking this icon.

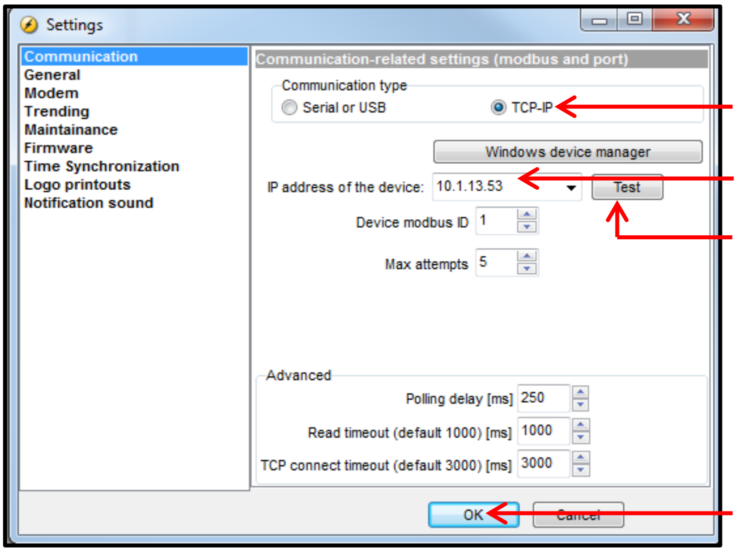


Select Serial if USB cable is used

Press Scan Ports to the communication port

Select com named as DEIF USB to UART

Press OK



Select TCP-IP if TCP-IP is used

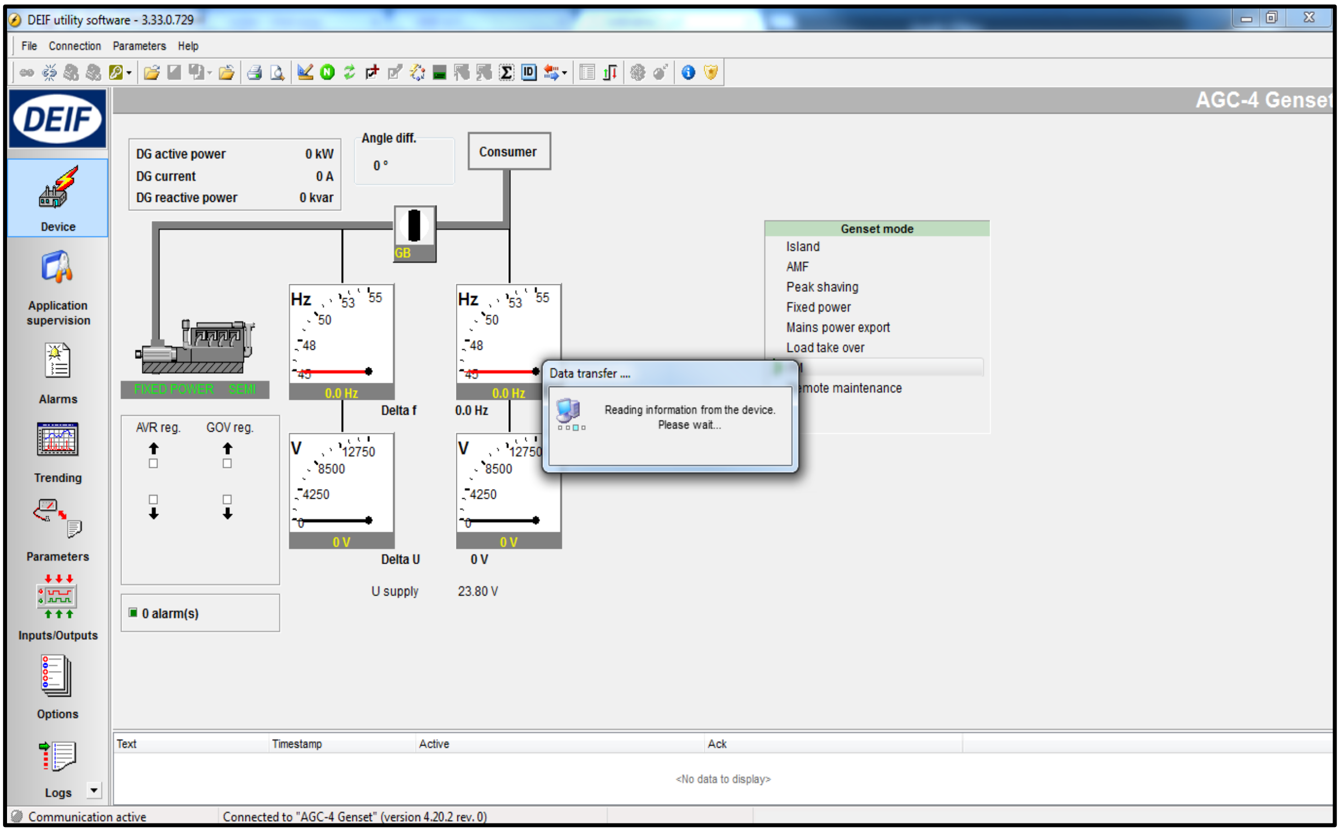
Enter IP Address

Press Test to Verify connection

Press OK

Click the connect button using icon. 

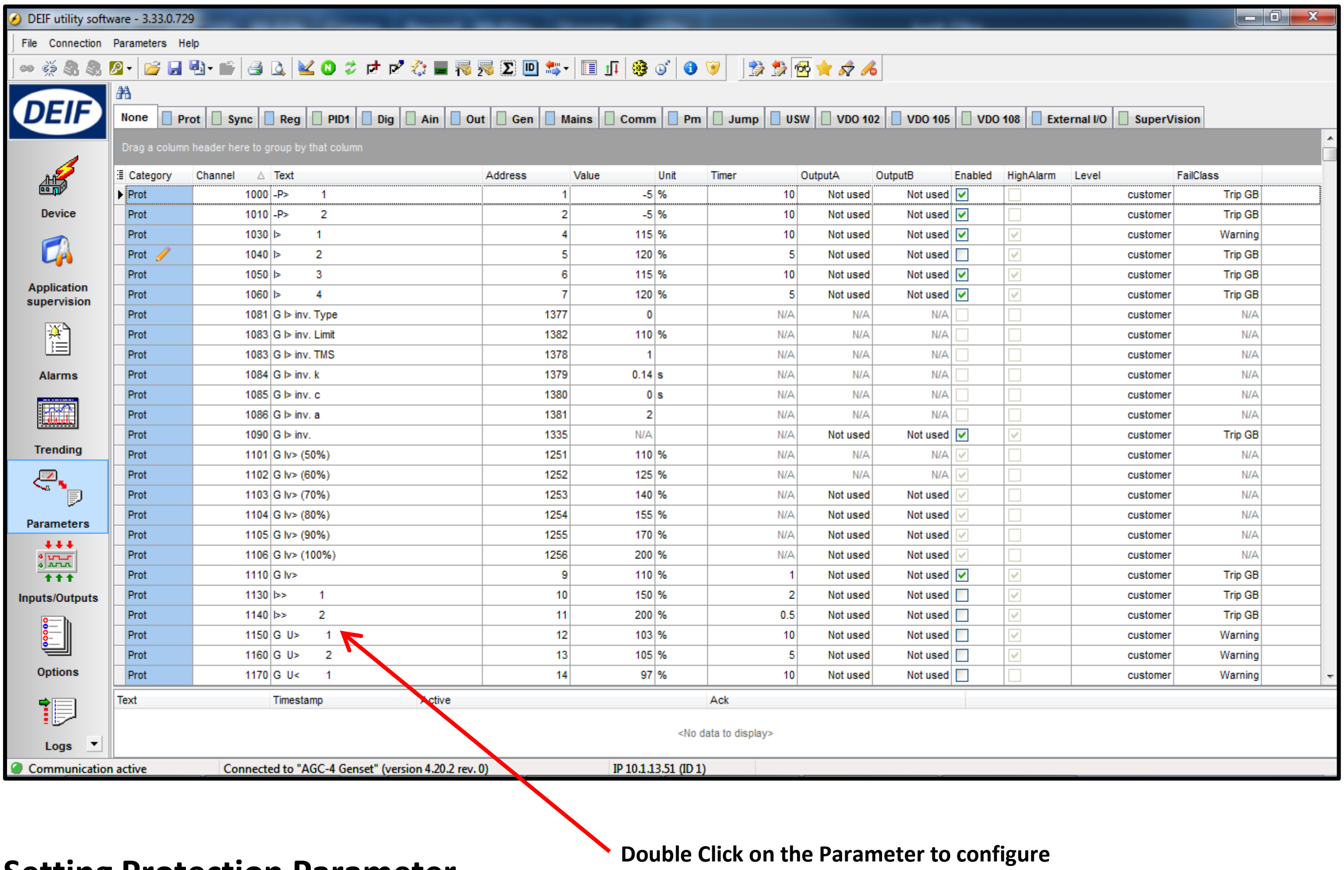
Once the connection Utility will upload the information & then you will be online with the AGC



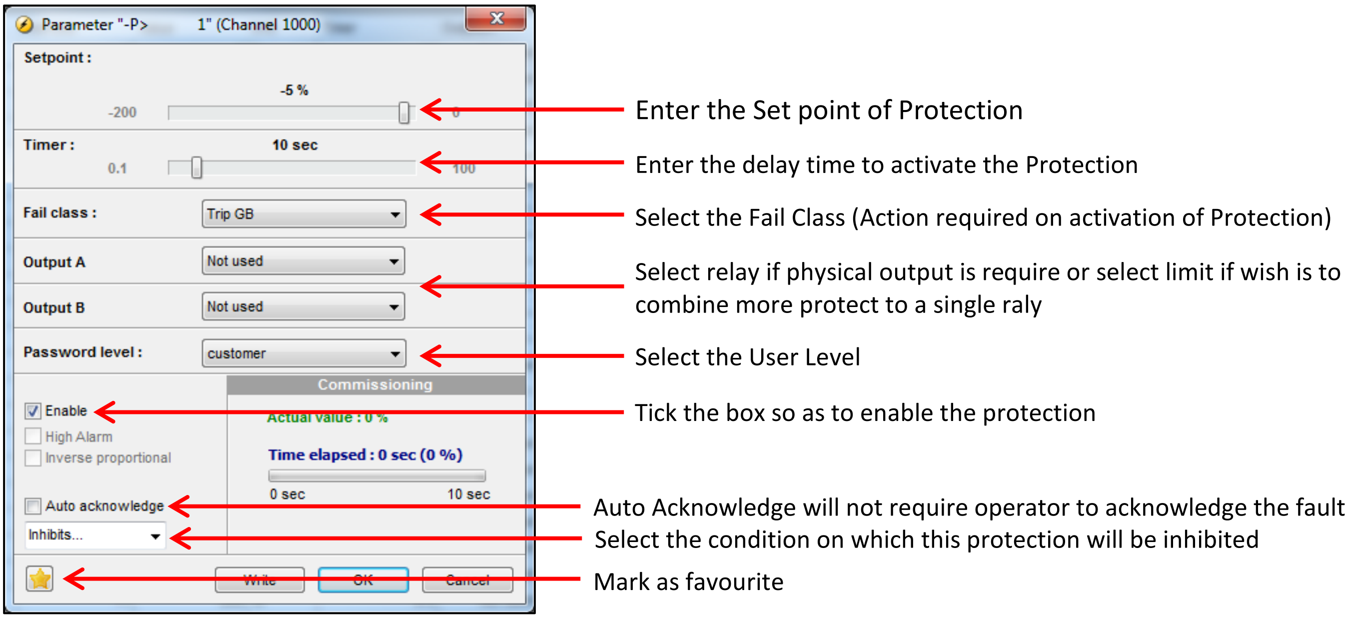
Description of Tabs:-

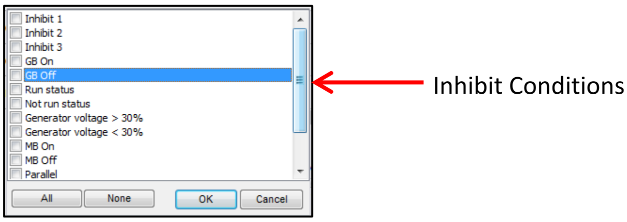
Device	This tab is used to view the mimic page of device
Alarms	This tab is used to view all the active alarms
Trending	This tab is used to view the trends of electrical parameter
Parameters	This tab is used to view or set the controller parameters.
Inputs/Outputs	This tab is used to view the input/output status of the device
Options	This tab is used to view the option active or de-active in the device
Logs	This tab is used to get historic alarm/event logs
Translations	This tab is used to view or set the translation of device text
M-Logic	This tab is used to write the customization of events through logical gates.
Application configuration	This tab is used to configure the device.

9. Parameters



Setting Protection Parameter





9.1 Step by Step Configuring AGC 4 GEN for Turbine

1. **Set the Communication Parameters.**

❖ Communication					
Category	**Channel**	**Text**	**Value**	**Unit**	**Description**
Comm	7511	Ext. comm. ID	2		Modbus Communication ID
Comm	7531	Int. comm. ID	2		Internal CAN Communication ID

Parameter 7511 is for setting up ID for Modbus RS 485/232/422

Available ID 1 - 247

Parameter 7531 is for setting up Intra Controller CAN communication

AGC 4 Genset	Available CAN ID 1 - 16
AGC 4 Mains	Available CAN ID 17 - 32
AGC 4 BTB	Available CAN ID 33 - 40

2. **Change Scaling from Parameter No. 9030 as per plant Voltage Level & requirement i.e. operator need Power in KW or MW.**

❖ Jump					
Category	**Channel**	**Text**	**Value**	**Unit**	**Description**
Jump	9030	Scaling	1		Scaling the Voltage Level

Value	Voltage Range	Available KW/MW Range
0	10V - 2500V	1 - 900 KW
1	100V - 25000V	10 - 20000 KW
2	10 kV - 160 kV	1 - 900 MW
3	1 kV -75 kV	1 - 90 MW

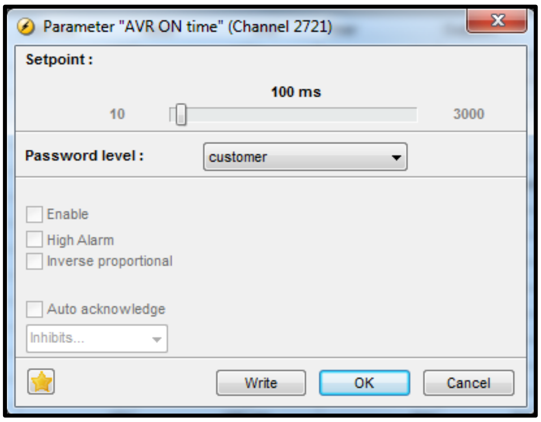
3. Set Nominal Parameters

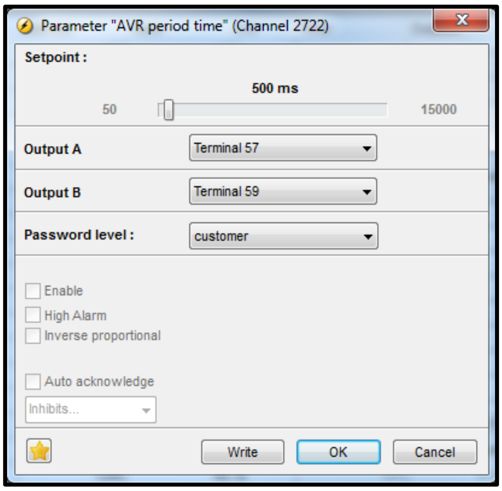
❖ General Setup					
Category	**Channel**	**Text**	**Value**	**Unit**	**Description**
Gen	6001	Nom. f 1	50	Hz	Rated Frequency of Alternator
Gen	6002	Nom. P 1	4000	kW	Rated Power of Alternator
Gen	6003	Nom. I 1	262	A	Rated Current of Alternator
Gen	6004	Nom. U 1	11000	V	Rated Voltage of Alternator
Gen	6005	Nom. rpm 1	1500	RPM	Rated RPM of Alternator
Gen	6006	Enable nom. set	0		Enable Nominal Setting Set 1
Gen	6041	G primary U	400	V	Turbine Side PT Primary Voltage
Gen	6042	G secondary U	400	V	Turbine Side PT Secondary Voltage
Gen	6043	G Primary I	1000	A	Turbine Side CT Primary Current
Gen	6044	G Secondary I	1	A	Turbine Side CT Secondary Current
Gen	6051	BB primary U 1	400	V	Busbar Side PT Primary Voltage
Gen	6052	BB second. U 1	400	V	Busbar Side PT Secondary Voltage
Gen	6053	BB Nominal U 1	11000	V	Busbar Rated Voltage
Gen	6054	Bus nom. set	0		Enable Busbar Nominal Setting Set 1
Gen	6070	Turbine Mode	6		Turbine mode will be Power Management
Gen	6220	Hz/V OK			Delay Time to consider Hz/V Ok

4. Set Governor and AVR Regulation Control Type & Corresponding Regulation Parameter.

Category	Channel	Text	Value-Unit		Description
Reg	2782	Reg. output GOV	0		Select reg. output 0=Relay , 1=Analog
Reg	2783	Reg. output AVR	0		Select reg. output 0=Relay , 1=Analog

(If Governor & AVR Regulation output is 0=Relay)





Category	Channel	Text	Value	Delay	Description
Reg	**2570**	**f control relay**			
	2571	f Deadband	1%		Deadband of controller for frequency regulation
	2572	f Kp relay	10		Proportional gain of controller for frequency
Reg	**2580**	**P control relay**			
	2581	P Deadband	1%		Deadband of controller for power regulation
	2582	P Kp relay	10		Proportional gain of controller for power
Reg	**2590**	**P ls. control relay**			
	2591	P ls. F Deadband	1%		Deadband of frequency for load sharing
	2592	P ls. F Kp relay	10		Proportional gain of freq. controller for load sharing
	2593	P ls. P deadband	2		Deadband of power in load sharing
	2594	P ls. P weight	10 %		Weight Factor of power in load sharing
Reg	**2690**	**Q control relay**			
	2691	U Deadband	2%		Deadband of controller for Voltage regulation
	2692	U Kp relay	10		Proportional gain of controller for Voltage
Reg	**2700**	**Q control relay**			
	2701	Q Deadband	1%		Deadband of controller for PF regulation
	2702	Q Kp relay	10		Proportional gain of controller for PF
Reg	**2710**	**Q ls. control relay**			
	2711	Q loadsh. U Kp	1%		Deadband of voltage for load sharing
	2712	Q loadsh. U Ti	10		Proportional gain of Volt. controller for load sharing
	2713	Q loadsh. U Td	2 %		Deadband of KVAR sharing
	2714	Q LS Q weight	10 %		Weight Factor of power in KVAR sharing

(If Regulation output is 1=Analog)					
Category	**Channel**	**Text**	**Value**	**Delay**	**Description**
Reg	**2510**	**f control**			
	2511	f Kp	0.5		Proportional Gain value of PID regulator for Frequency
	2512	f Ti	5		Integral Time value of PID regulator for Frequency
	2513	f Td	0		Differential Time Value of PID regulator for Frequency
Reg	**2530**	**P control**			
	2531	P Kp	0.5		Proportional Gain value of PID regulator for Power
	2532	P Ti	5		Integral Time value of PID regulator for Power
	2533	P Td	0		Differential Time Value of PID regulator for Power
Reg	**2540**	**P ls. control**			
	2541	P loadsh. f Kp	0.5		Proportional Gain value of PID regulator for load share
	2542	P loadsh. f Ti	5 s		Integral Time value of PID regulator for load share
	2543	P loadsh. f Td	0 s		Differential Time Value of PID regulator for load share
	2544	P LS P weight	10 %		Weight Factor of power in load sharing
Reg	**2550**	GOV output offset			
	2550	GOV output offset 1	50%		Output Offset 1 of PID controller for GOV control
	2551	GOV output offset 2	50%		Output Offset 2 of PID controller for GOV control
	2552	GOV output offset3	50%		Output Offset 3 of PID controller for GOV control
	2553	GOV output offset 4	50%		Output Offset 4 of PID controller for GOV control
Reg	**2640**	**U control**			
	2641	U Kp	0.5		Proportional Gain value of PID regulator for Voltage
	2642	U Ti	5		Integral Time value of PID regulator for Voltage
	2643	U Td	0		Differential Time Value of PID regulator for Voltage
Reg	**2650**	**Q control**			
	2651	Q Kp	0.5		Proportional Gain value of PID regulator for PF
	2652	Q Ti	5		Integral Time value of PID regulator for PF
	2653	Q Td	0		Differential Time Value of PID regulator for PF
	2654	PF ramp Up	2 %/s		PF ramp up speed
	2655	PF ramp Down	2 %/s		PF ramp down speed
Reg	**2660**	**Q ls. control**			
	2661	Q ls. Kp	0.5		Proportional Gain value of PID regulator for KVAR
	2662	Q ls. Ti	5		Integral Time value of PID regulator for KVAR
	2663	Q ls. Td	0		Differential Time Value of PID regulator for KVAR
	2664	Q ls. Q weight	10 %		Weight Factor of power in KVAR sharing
Reg	**2670**	AVR output offset			
	2670	AVR output offset 1	50%		Output Offset 1 of PID controller for AVR control
	2671	AVR output offset 2	50%		Output Offset 2 of PID controller for AVR control
	2672	AVR output offset3	50%		Output Offset 3 of PID controller for AVR control
	2673	AVR output offset 4	50%		Output Offset 4 of PID controller for AVR control

5. Set Synchronization Parameter.

❖ Synchronisation					
Category	**Channel**	**Text**	**Value-Unit**		**Description**
Sync	2000	Sync. Type	N/A		Dynamic or Static Sync.
Sync	**2020**	**Dynamic Synchronisation**			
Sync	2021	Sync. dfMax	0.3	Hz	Max. Allowable Frequency
	2022	Sync. dfMin	0	Hz	Min. Allowable Frequency
	2023	Sync. dUMax	5	%	Max. Allowable Voltage
	2024	Sync. t GB	50	ms	Max. Allowable Breaker closing time
	2025	Sync. t MB	50	ms	Max. Allowable Mains Breaker closing time
Sync	**2030**	**Static Synchronisation**			
	2031	Maximum df	0.1	Hz	Max. Allowable Frequency
	2032	Maximum dU	5	%	Max. Allowable Voltage
	2033	Closing window	10	deg	Max. Allowable Phase Angle
	2034	Static sync		s	Min. time in phase window before closing
	2035	Static type	1		Static Sync type for GB & MB i.e. close or just sync check without closing of breaker
	2036	Static type	1		
Sync	**2110**	**Sync. Black out**			
Sync	2111	Blackout dfMax	3	Hz	Max/Min allowable frequency & voltage difference from nominal while black out closing. This setting is also used to determine Hz/V OK
Sync	2112	Blackout dUMax	5	%	
Sync	2130	GB Sync Failure			Enable & Enter the Delay time
Sync	2150	Phase Sequence error			Enter Fail class
Sync	2160	GB Open fail			Enter the delay & fail class
Sync	2170	GB Close fail			Enter the delay & fail class
Sync	2180	GB pos. Fail			Enter fail Class

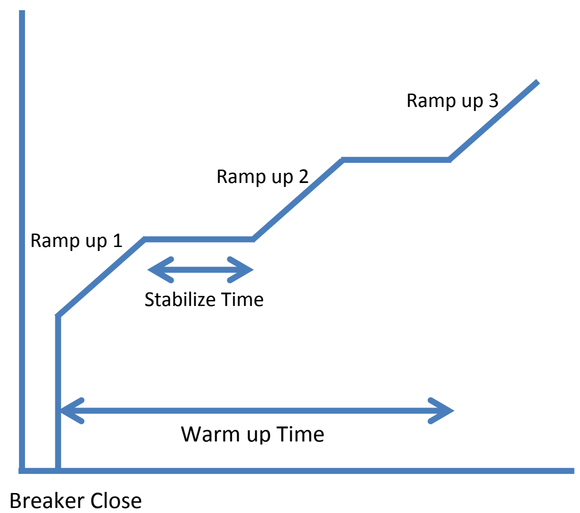
Sync. Regulator Parameter (if the Dynamic Sync. & GOV 2782 & AVR 2783 out put are Analog					
Sync	2041	f sync. Kp	0.5		Proportional Gain value of PID regulator for Freq. Sync
Sync	2042	f sync. Ti	5	sec	Integral Time value of PID regulator for Freq. Sync
Sync	2043	f sync. Td	0	sec	Differential Time Value of PID regulator of Freq. Sync
Sync	2061	Phase Kp	0.5		Proportional Gain value of PID regulator for Phase sync
Sync	2062	Phase Ti	5	sec	Integral Time value of PID regulator for Phase sync
Sync	2063	Phase Td	0	sec	Differential Time Value of PID regulator for Phase sync

Sync. Regulator Parameter (If the GOV 2782 & AVR 2783 out put is Relay) & Dynamic Sync. is selected					
Sync	2050	f Sync Kp relay	10		Proportional Gain value of regulator for frequency

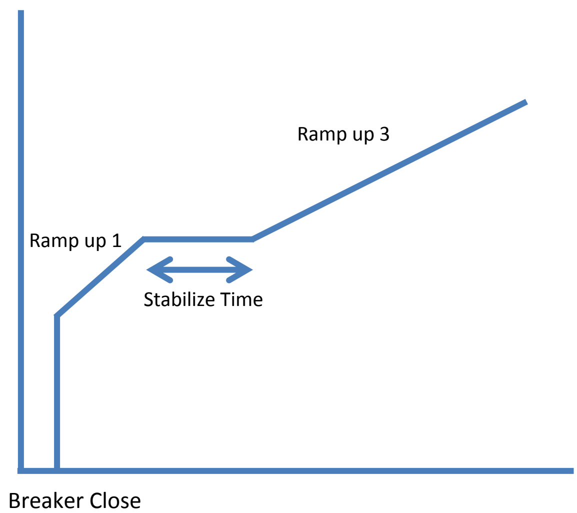
6. Set Regulation monitoring parameter & Ramp rates.

❖ Regulation After Breaker is Closed

Category	Channel	Text	Value	Delay	Description
Reg	2560	GOV Reg. Fail	30 %	60 s	Select GOV reg. fail point with delay
Reg	2680	AVR Reg. Fail	30 %	60 s	Select GOV reg. fail point with delay
Reg	2630	Deload error		10 s	Alarm raise if turbine do not reaches ramp down point 2622 is not within time when breaker open command is active
Reg	**2610**	**Power ramp up**			
Reg	2526	Stabilize Time	100 S		Time to wait at 1 ramp up point/Minimum load (7023)
Reg	2611	Power ramp up 1	2 %/s		Power Ramp up speed 1
Reg	2612	Power ramp up	10 %	10 s	Power ramp up delay point
Reg	2614	Power ramp up			Power ramp up steps enable
Reg	2615	Power ramp up	1		Power ramp up steps
Reg	2616	Power ramp up 2	2 %/s		Power Ramp up speed 2 after delay point
Reg	2621	Power ramp down 1	10%/s		Power Ramp down speed 1
Reg	2622	Power ramp down	5 %		Max allowable power when opening breaker
Reg	2623	Power rampdown2	10%/s		Power Ramp down speed2
Reg	2521	Warmup Timer	60 min		Time after CB Close when Ramp rate 3 will be active
Reg	2522	Cool down timer	30 min		Time after CB Open when Ramp rate 3 will be inactive
Reg	2523	Power ramp up 3	1 %/s		Power Ramp up speed 2
Reg	2524	Power ramp up 3	1 %/s		Power Ramp up speed 2
Reg	2525	Power Setp. ROC	1%		Rate of change of Fixed Power Setpoint per pulse



Ramp rates When Breaker closed after cool down time is elapsed



Ramp rates When Breaker closed after cool down time is elapsed

7. Set Mains related parameter.

❖ Mains					
Category	**Channel**	**Text**	**Value**	**Unit**	**Description**
Mains	7023	Minimum Load	5	%	Minimum Load on turbine when synchronized with grid
Mains	7051	Contr. Settings P	500	KW	Fixed Power Setpoint (When Genset mode 6070 is fixed)
Mains	7052	Contr. Settings cosphi	0.8		PF setpoint
Mains	7053	Contr. Settings cosphi	0		0 = Inductive 1 = Capacitive
Mains	7055	Contr. Settings P	0		Scaling for Fixed Power Setpoint 0 :- 1KW = 1 KW 1 :- 1KW = 10 KW 2 :- 1KW = 100 KW 3 :- 1KW = 1000 KW
Range of Power factor in Turbines Power factor will vary					
Mains	7171	Cosphi (X2) slp.	0.7		Minimum Power Factor
Mains	7172	Cosphi (X2) slp.	0		0 = Inductive 1 = Capacitive
Mains	7173	Cosphi (X2) slp.	0.8		Maximum Power Factor
Mains	7174	Cosphi (X2) slp.	0		0 = Inductive 1 = Capacitive
Mains	7083	Back Synchronising			Back Sync. Of Turbine to Mains permission
Mains	7084	Sync. to mains			Sync. To Mains permission

8. Setting up Digital Input & outputs.

❖ Digital Input

Category	Channel	Text	Value	Unit	Description
Dig	3490	Emergency STOP	N/A		Enable/Disable Emergency Stop

❖ Digital Output

Category	Channel	Text	Value	OFF Delay	Description
Out	5000	Relay 05	0	5.0 s	Select Relay type 0 = Alarm Relay ND (Default) Select Relay type 1 = Limit Relay Select Relay type 2 = Horn Relay Select Relay type 3 = Siren Relay Select Relay type 4 = Alarm Relay NE
Out	5010	Relay 08	0	5.0 s	
Out	5020	Relay 11	0	5.0 s	
Out	5030	Relay 14	0	5.0 s	
Out	5110	Relay 57	0	5.0 s	
Out	5120	Relay 59	0	5.0 s	
Out	5130	Relay 61	0	5.0 s	
Out	5140	Relay 63	0	5.0 s	

Relay type 0	Alarm Relay ND (normally De-energize)	If selected then the relay will operate by Controller Alarm Handling System or by regulators
Relay type 1	Limit Relay	If selected then the relay will operate by M-Logic Commands
Relay type 2	Horn Relay	If selected then the relay will operate when alarm appears & remain on for time set in Parameter 6130 Alarm horn till alarm is unacknowledged.
Relay type 3	Siren Relay	If selected then the relay will operate when alarm appears & remain on for time set in Parameter 6130 Alarm horn till alarm is unacknowledged.
Relay type 4	Alarm Relay NE (normally Energize)	If selected then the relay will operate by Controller Alarm Handling System or by regulators

9.2 Step by Step Configuring AGC 4 Mains for Grid

1. **Set the Communication Parameters.**

❖ Communication					
Category	**Channel**	**Text**	**Value**	**Unit**	**Description**
Comm	7511	Ext. comm. ID	2		Modbus Communication ID
Comm	7531	Int. comm. ID	2		Internal CAN Communication ID

Parameter 7511 is for setting up ID for Modbus RS 485/232/422

Available ID 1 - 247

Parameter 7531 is for setting up Intra Controller CAN communication

AGC 4 Genset	Available CAN ID 1 - 16
AGC 4 Mains	Available CAN ID 17 - 32
AGC 4 BTB	Available CAN ID 33 - 40

2. **Change Scaling from Parameter No. 9030 as per plant Voltage Level & requirement i.e. operator need Power in KW or MW.**

❖ Jump					
Category	**Channel**	**Text**	**Value**	**Unit**	**Description**
Jump	9030	Scaling	1		Scaling the Voltage Level

Value	Voltage Range	Available KW/MW Range
0	10V - 2500V	1 - 900 KW
1	100V - 25000V	10 - 20000 KW
2	10 kV - 160 kV	1 - 900 MW
3	1 kV -75 kV	1 - 90 MW

3. Set Nominal Parameters

❖ General Setup					
Category	**Channel**	**Text**	**Value**	**Unit**	**Description**
Gen	6001	Nom. f 1	50	Hz	Rated Frequency of Transformer/Grid
Gen	6002	Nom. P 1	4000	kW	Rated Power of Transformer/Grid
Gen	6003	Nom. I 1	262	A	Rated Current of Transformer/Grid
Gen	6004	Nom. U 1	11000	V	Rated Voltage of Transformer/Grid
Gen	6006	Enable nom. set	0		Enable Nominal Setting Set 1
Gen	6041	M primary U	400	V	Transformer/Grid Side PT Primary Voltage
Gen	6042	M secondary U	400	V	Transformer/Grid Side PT Secondary Voltage
Gen	6043	M Primary I	1000	A	Transformer/Grid Side CT Primary Current
Gen	6044	M Secondary I	1	A	Transformer/Grid Side CT Secondary Current
Gen	6051	BB primary U 1	400	V	Busbar Side PT Primary Voltage
Gen	6052	BB second. U 1	400	V	Busbar Side PT Secondary Voltage
Gen	6053	BB Nominal U 1	11000	V	Busbar Rated Voltage
Gen	6054	Bus nom. set	0		Enable Busbar Nominal Setting Set 1
Gen	6070	Plant Mode	6		Plant mode could be :- 0 = Island 2 = Peak shaving 3 = Fixed Power 4 = Mains Power Export

4. Set Mains parameter.

❖ Mains						
Category	**Channel**	**Text**	**Value**	**Unit**	**Description**	
Mains	7001	Day Setting	750	kW	Import/Export Set point at Day Time	
Mains	7002	Night Setting	1000	kW	Import/Export Set point at Night Time	
Mains	7005	Mains Power	0		Scaling for Import/Export Setpoint 0 :- 1KW = 1 KW 1 :- 1KW = 10 KW 2 :- 1KW = 100 KW 3 :- 1KW = 1000 KW	
Mains	7011	Start Hour	8		Day Time Start hour	If Start Hour & Stop Hour is same then both setting are same
Mains	7012	Start Minute	0		Day Time Start Minute	
Mains	7013	Stop Hour	16		Night Time Start Hour	
Mains	7014	Stop Minute	0		Night Time Start Minute	
Mains	7051	Contr. Settings P	500	KW	Fixed Power Setpoint	
Mains	7052	Contr. Settings cosphi			PF setpoint	
Mains	7053	Contr. Settings cosphi	1		0 = Inductive 1 = Capacitive	
Mains	7054	Contr. Settings cosphi	2		How mains will give PF set point to TGs 0 = Off (mains will not give PF set point to TG) 1 = Fixed for TG (mains will give fixed PF set point to all TG) 2 = Fixed for Import/Export (mains will vary PF set point of all TG so as to maintain Grid PF)	
Mains	7055	Contr. Settings P	0		Scaling for Fixed Power Setpoint 0 :- 1KW = 1 KW 1 :- 1KW = 10 KW 2 :- 1KW = 100 KW 3 :- 1KW = 1000 KW	
Range of Power factor in which Mains will vary Turbines Power factor						
Mains	7171	Cosphi (X2) slp.	0.7		Minimum Power Factor	
Mains	7172	Cosphi (X2) slp.	0		0 = Inductive 1 = Capacitive	
Mains	7173	Cosphi (X2) slp.	0.8		Maximum Power Factor	
Mains	7174	Cosphi (X2) slp.	0		0 = Inductive 1 = Capacitive	
Mains	7083	Back Synchronising			Back Sync. Of Turbine to Mains permission	
Mains	7084	Sync. to mains			Sync. To Mains permission	

5. Set regulation parameter.

Category	Channel	Text	Value	Unit	Description
Reg	2525	Power Setp. ROC	100	Kw/s	Rate of change of Fixed Power Setpoint per pulse Rate of change of Import Power Setpoint per pulse Rate of change of Export Power Setpoint per pulse

9.3 Step by Step Configuring AGC 4 BTB for Bus Coupler

1. **Set the Communication Parameters.**

❖ Communication					
Category	**Channel**	**Text**	**Value**	**Unit**	**Description**
Comm	7511	Ext. comm. ID	2		Modbus Communication ID
Comm	7531	Int. comm. ID	2		Internal CAN Communication ID

Parameter 7511 is for setting up ID for Modbus RS 485/232/422

Available ID 1 - 247

Parameter 7531 is for setting up Intra Controller CAN communication

AGC 4 Genset Available CAN ID 1 - 16
AGC 4 Mains Available CAN ID 17 - 32
AGC 4 BTB Available CAN ID 33 - 40

2. **Change Scaling from Parameter No. 9030 as per plant Voltage Level & requirement i.e. operator need Power in KW or MW.**

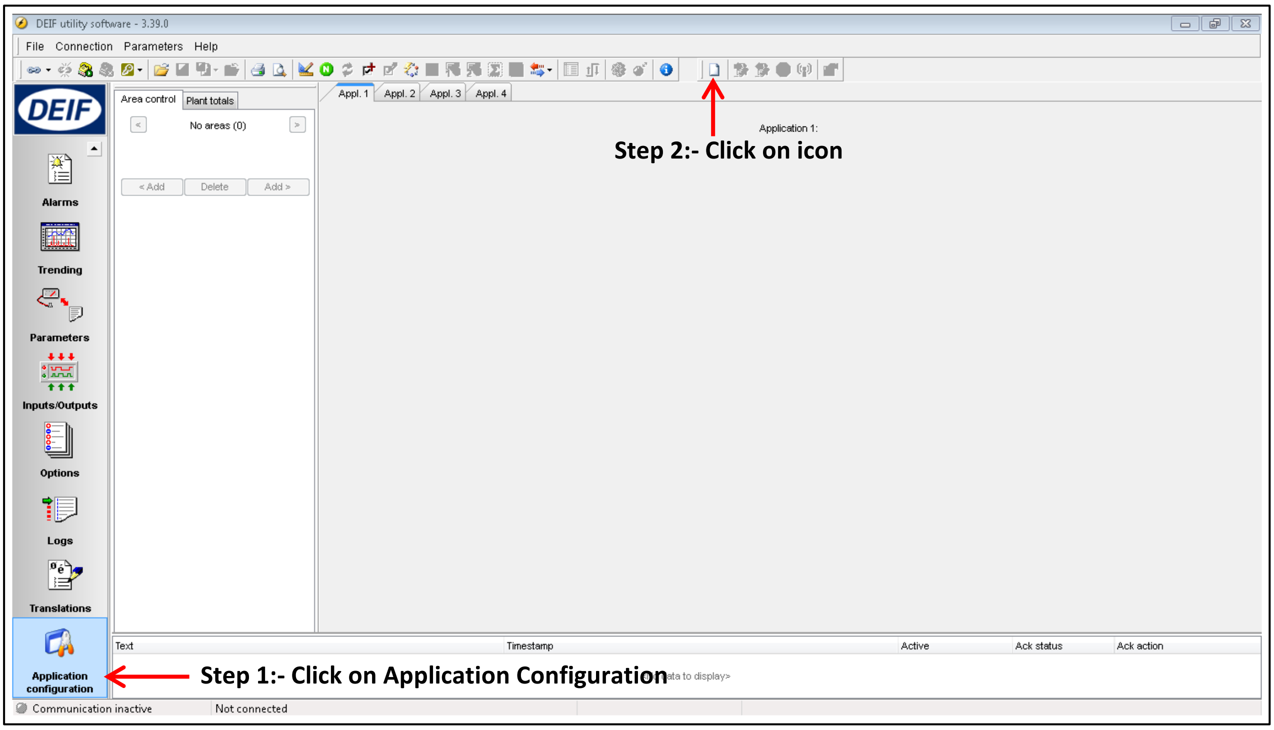
❖ Jump					
Category	**Channel**	**Text**	**Value**	**Unit**	**Description**
Jump	9030	Scaling	1		Scaling the Voltage Level

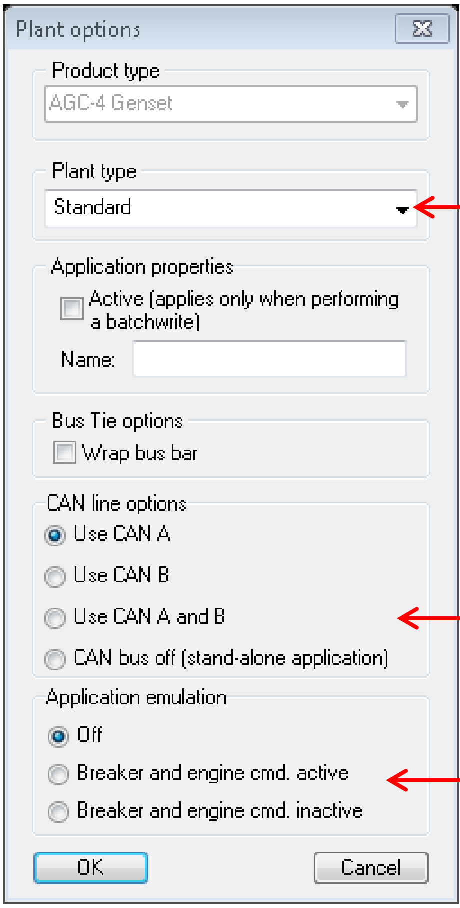
Value	Voltage Range	Available KW/MW Range
0	10V - 2500V	1 - 900 KW
1	100V - 25000V	10 - 20000 KW
2	10 kV - 160 kV	1 - 900 MW
3	1 kV -75 kV	1 - 90 MW

3. Set Nominal Parameters

❖ General Setup					
Category	**Channel**	**Text**	**Value**	**Unit**	**Description**
Gen	6001	Nom. f 1	50	Hz	Rated Frequency
Gen	6002	Nom. P 1	4000	kW	Rated Power
Gen	6003	Nom. I 1	262	A	Rated Current
Gen	6004	Nom. U 1	11000	V	Rated Voltage
Gen	6006	Enable nom. set	0		Enable Nominal Setting Set 1
Gen	6041	BA primary U	400	V	Bus Bar A side PT Primary Voltage
Gen	6042	BA secondary U	400	V	Bus Bar A side PT Secondary Voltage
Gen	6043	BA Primary I	1000	A	Bus Bar A side CT Primary Current
Gen	6044	BA Secondary I	1	A	Bus Bar A side CT Secondary Current
Gen	6051	BB primary U 1	400	V	Busbar B Side PT Primary Voltage
Gen	6052	BB second. U 1	400	V	Busbar B Side PT Secondary Voltage
Gen	6053	BB Nominal U 1	11000	V	Busbar B side Rated Voltage
Gen	6054	Bus nom. set	0		Enable Busbar Nominal Setting Set 1

10. Creating Application in AGC 4

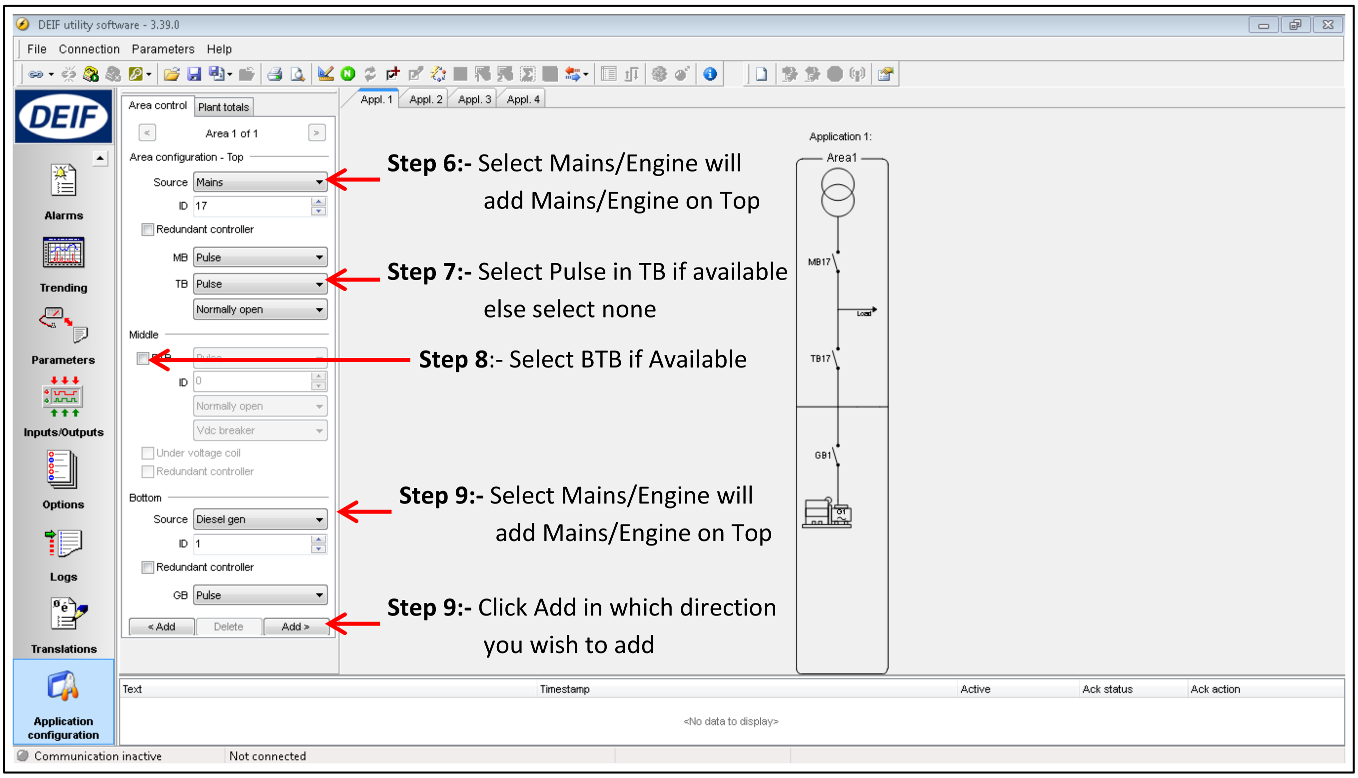


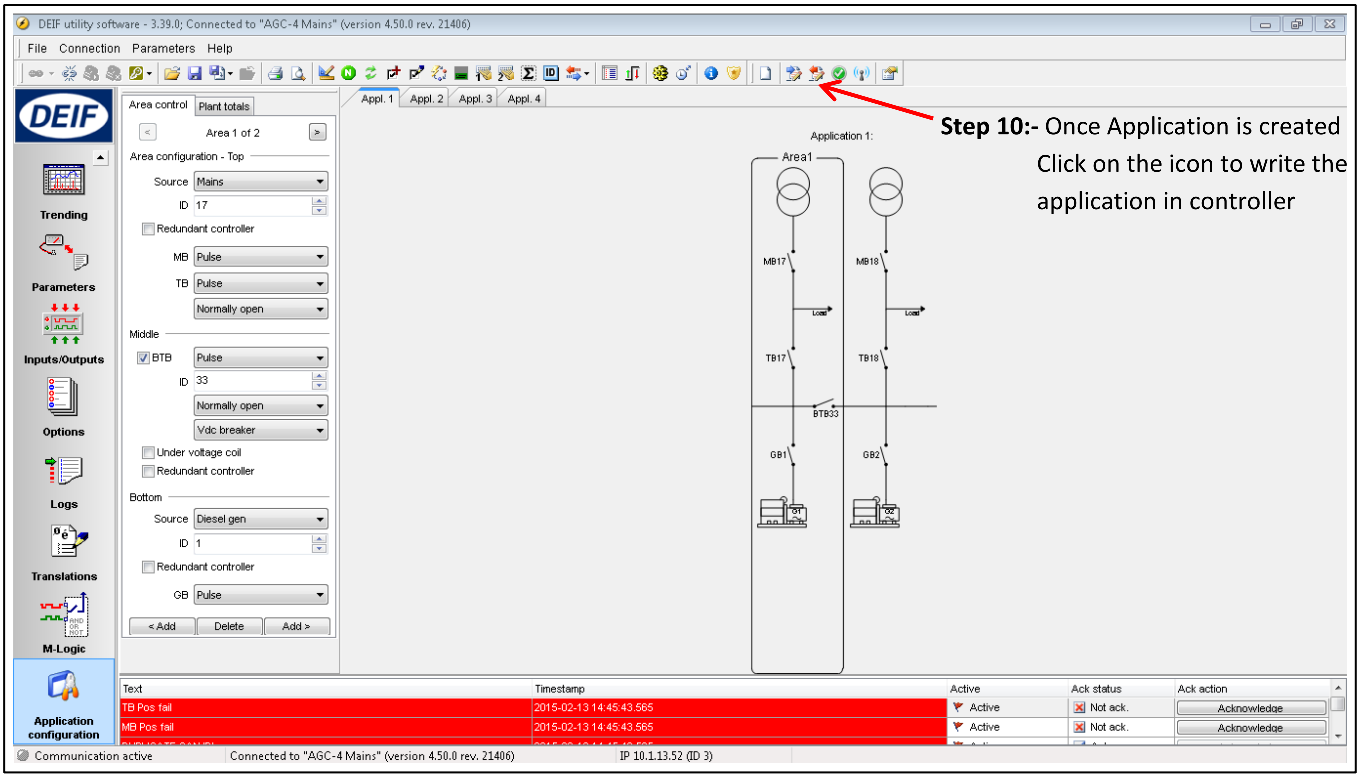


Step 3:- Select Plant type Standard

Step 4:- Select CAN A or CAN B or Both as per wiring

Step 5:- Emulation will be off

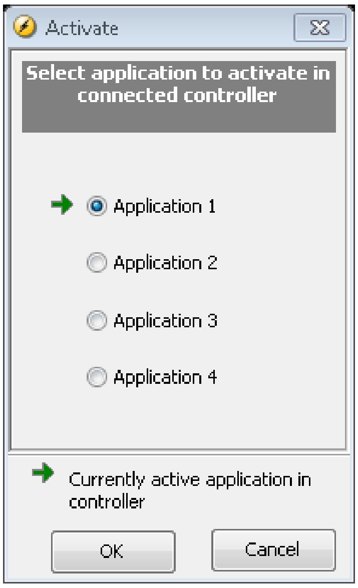

DEIF utility software - 3.39.0
Step 6:- Select Mains/Engine will add Mains/Engine on Top
Step 7:- Select Pulse in TB if available else select none
Step 8:- Select BTB if Available
Step 9:- Select Mains/Engine will add Mains/Engine on Top
Step 9:- Click Add in which direction you wish to add


DEIF utility software - 3.39.0; Connected to "AGC-4 Mains" (version 4.50.0 rev. 21406)
Step 10:- Once Application is created Click on the icon to write the application in controller

 This icon is for reading the application from controller.

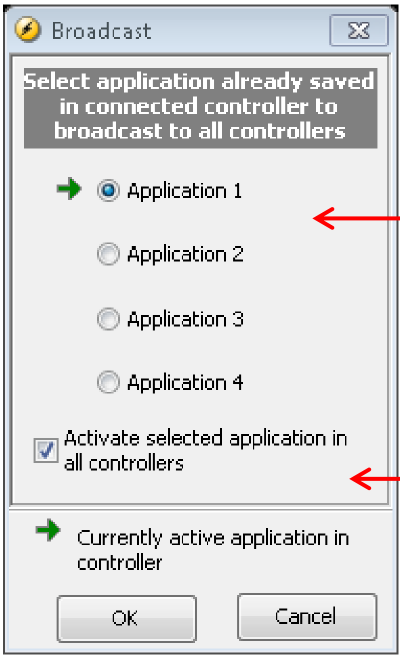
 This icon is for writing the application to the controller.

 This icon is for Activating the Application in the controller as there could be application in the controller & we can decide which will be active



 This icon is for Broad casting application to other controllers, this saves the time & you don't need to connect each controller & download the application. But for this connection to each controller must be ok with 120 ohm resistance in starting & end controller.

Also the Internal ID (7531) in each controller must be unique as per application.



Select which application to broadcast to other controller

You can simultaneously select to activate the application in all controllers.

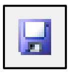
11.M-Logic

When the M-Logic screen is shown, the M-Logic toolbar appears at the top of the screen. The toolbar has two buttons which are used to write and read the M-Logic configuration to and from the unit.

The M-Logic configuration can also be saved / opened to/from a file using the default save/open buttons.

Read M-Logic settings from the unit
Activating this button will read all M-Logic settings from the unit to the USW

Write M-Logic settings to the unit
Activating this button will write the M-Logic settings from the USW to the unit.



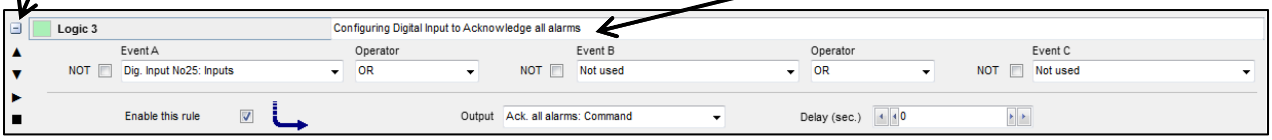
Save
Activating this button makes it possible to save the M-Logic configuration to file (part of the general Multi-line 2 configuration file ".USW").

Open
Activating this button makes it possible to open a previously saved logics file.

Basic functions

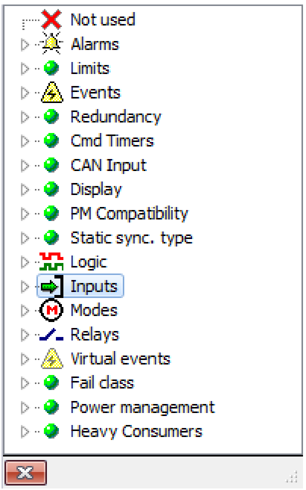
The M-Logic consists of a number of "lines", Logic 1, Logic 2 and so on. Each of these lines have 3 event settings, 2 operator settings, an enable tick box and one output setting.

The Logic line can be collapsed or expanded using this button. The free text will still be shown.



The free text is stored in the .usw file, but not in the product itself

The available functions are:



❖ Events A, B and C

These are used to trigger the logic.

Note that for each event the function "NOT" can be selected to get an inverted function.

When opening the roll-down window of the events, this window appears: → → →

Alarms:	Use an alarm to activate.
Limits:	Same as alarms, only with no time delay on binary inputs.
Events:	Events that are not alarms, e.g. "Engine running".
Cmd timers:	If the activating (triggering) event is required to be a pulse, these can be used (1 sec. pulse).
CAN inputs:	Status of M-logic functions broadcasted on the power management CAN line.
Logic:	Can be TRUE or FALSE. TRUE means always, FALSE means never.
Inputs:	Direct activation of a binary input. The availability of binary inputs is option-dependent.
Modes:	Are running modes and plant modes, e.g. "AUTO".
Relays:	Activation when a relay activates. The availability of relay outputs is option dependent.

Virtual events: Is a number of internal (virtual) events that can be activated from another logic line. By using these virtual events, the number of activating (triggering) events can be expanded from the 3 available in each logic line to, in theory, an unlimited number of events.

Fail class: The event activates upon activation of any alarm with the chosen fail class,e.g. “Shutdown”

Power management: Status related to power management, e.g. “All GB on”.

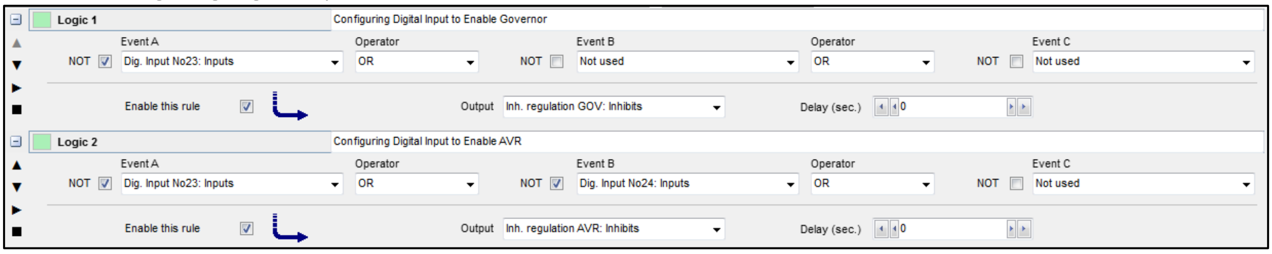
- **<u>Operators</u>**
  2 operators are available, and they can be:
  “OR” (any operator activates the function output),
  “AND” (all activated operators must have status ON to activate the function output).

- **<u>Enable the rule</u>**
  If this tick box is not ticked, the logic in question will not operate

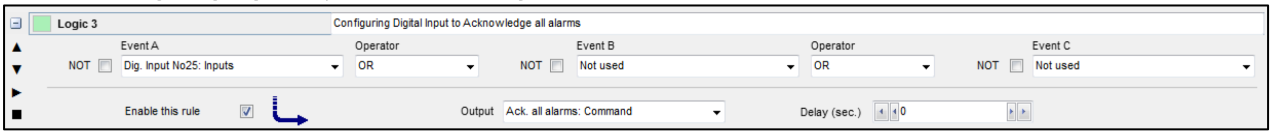
- **<u>Output</u>**
  This is the selection of the reaction of the system upon activation of the function. Note that the output has a delay function. If set to 0 s (default), there is no delay.

<u>M-Logic Examples:-</u>

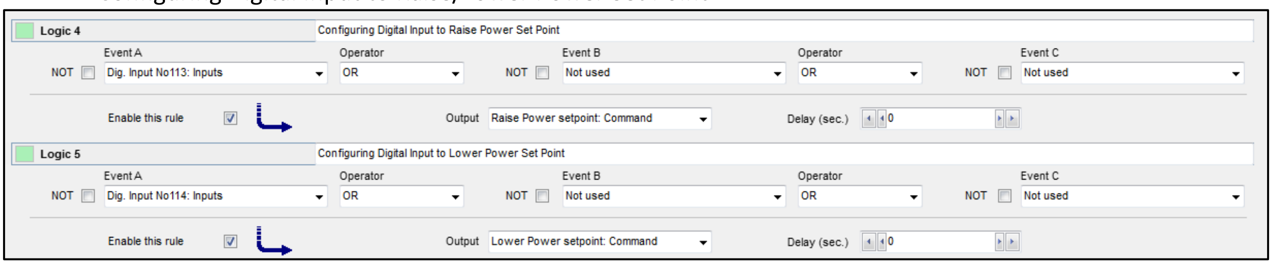
- Configuring Digital Input to Enable Governor & AVR



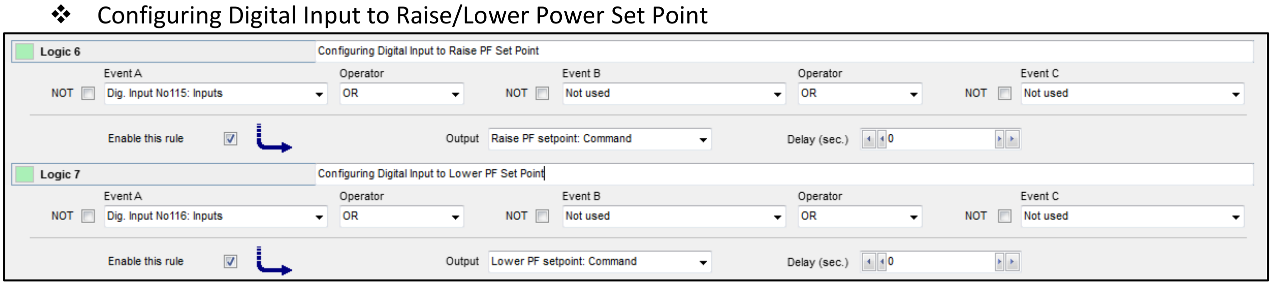
- Configuring Digital Input to Acknowledge all Alarms



- Configuring Digital Input to Raise/Lower Power Set Point



- Configuring Digital Input to Raise/Lower Power Set Point



12.Synchronisation

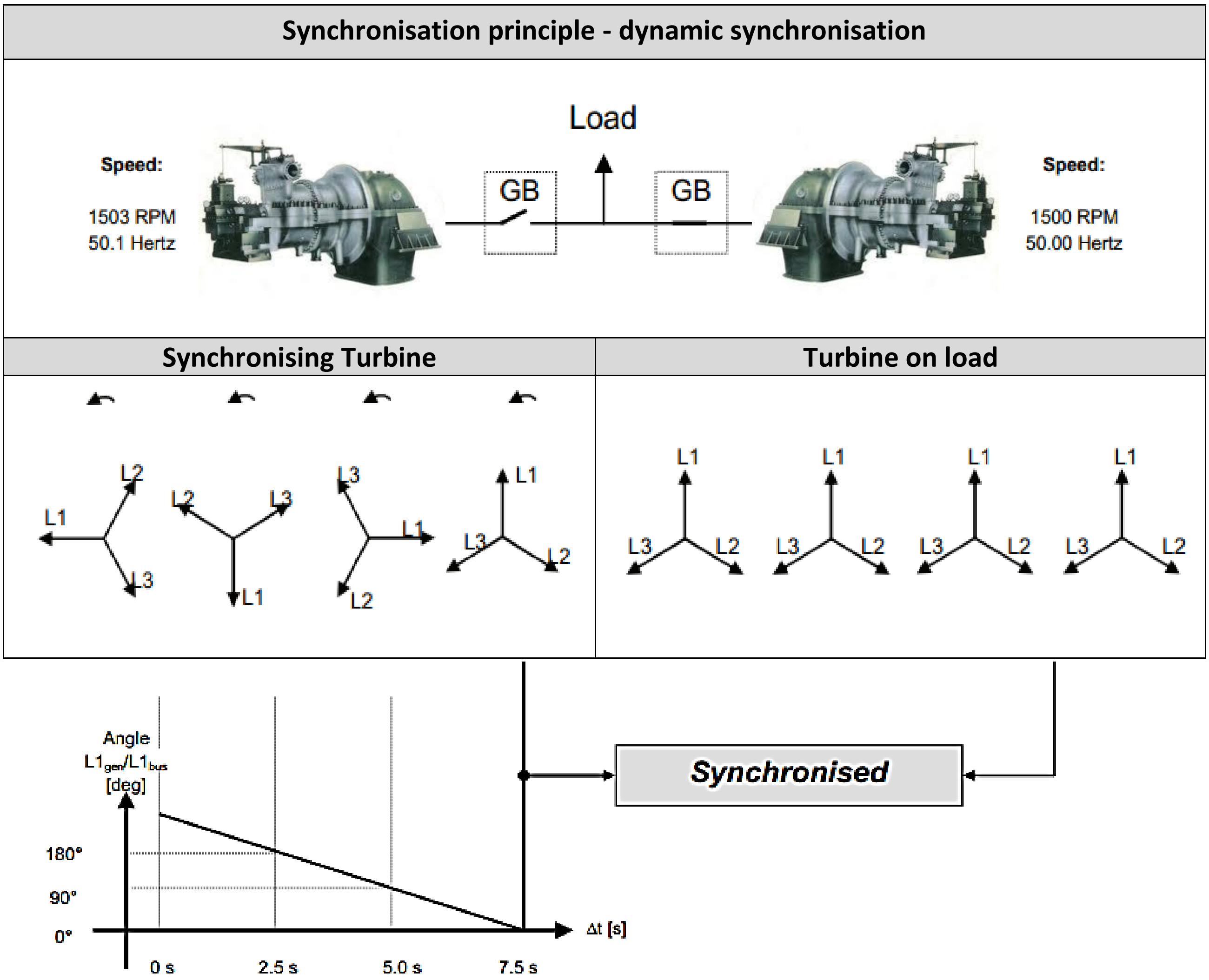
The unit can be used for synchronisation of turbine and mains breaker (if installed). Two different synchronisation principles are available, namely static and dynamic synchronisation (dynamic is selected by default). This chapter describes the principles of the synchronisation functions and the adjustment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

In the following the term 'synchronisation' means 'synchronising and closing of the synchronised breaker'.

Dynamic synchronisation

In dynamic synchronisation the synchronising turbine is running at a different speed than the turbine on the busbar. This speed difference is called slip frequency. Typically, the synchronising turbine is running with a positive slip frequency. This means that it is running with a higher speed than the turbine 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 turbine is running at 1503 RPM ~ 50.1Hz. The turbine on load is running at 1500 RPM ~ 50.0Hz. This gives the synchronising turbine a positive slip frequency of 0.1Hz.

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Of course both three-phase systems are rotating, but for illustrative purposes the vectors for the turbineon 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 turbine is running with a positive slip frequency of 0.1Hz compared to the busbar, then the two systems will be synchronised every 10 seconds.

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

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 turbine is synchronised to the busbar, and the breaker will be closed

Close signal

The unit 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 0.1Hz):

$$\deg_{CLOSE} = 360 * t_{CB} * f_{SLIP}$$
$$\deg_{CLOSE} = 360 * 0.250 * 0.1$$
$$\deg_{CLOSE} = 9\,\deg$$

The synchronisation pulse is always issued, so the closing of the breaker will occur at the 12 o'clock position.

The length of the synchronisation pulse is the response time + 20 ms (2020 Synchronisation).

Load picture after synchronising

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

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

Adjustments

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

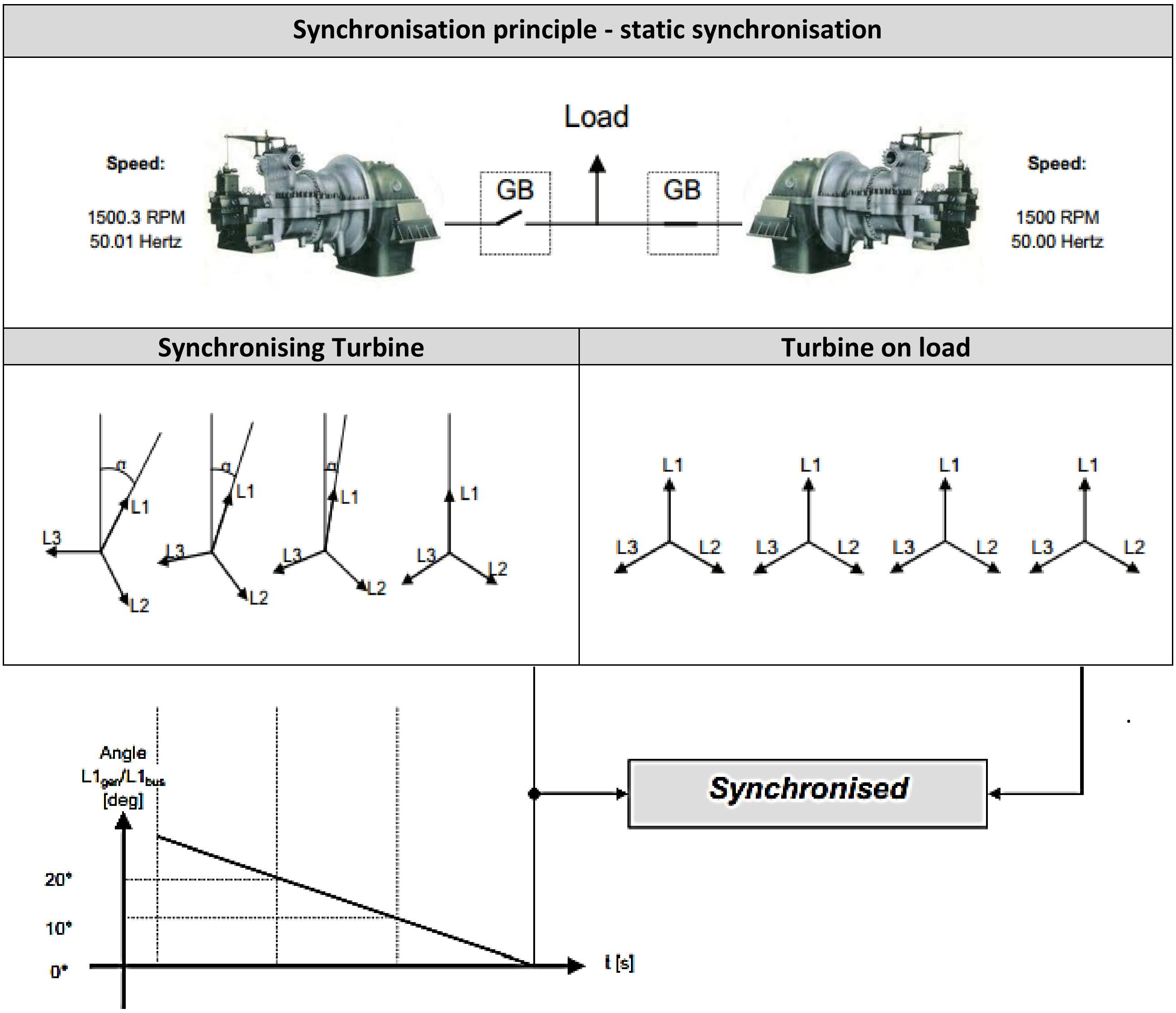
Setting	Description	Comment
2021 fMax	Maximum slip frequency.	Adjust the maximum positive slip frequency where synchronising is allowed.
2022 fMin	Minimum slip frequency.	Adjust the maximum negative slip frequency where synchronising is allowed.
2023 UMax	Maximum slip Voltage.	The maximum allowed voltage difference between the busbar/mains and the generator.
2023 UMin	Minimum slip Voltage.	The minimum allowed voltage difference between the busbar/mains and the generator.
2025 tGB	Turbine breaker closing time.	Adjust the response time of the turbine breaker.
2026 tMB	Mains breaker closing time	Adjust the response time of the mains breaker.

Static synchronisation

In static synchronisation, the synchronising turbine is running very close to the same speed as the turbineon 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 turbineand the three-phase system of the busbar matching exactly.

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

The static principle is illustrated below.



Phase controller

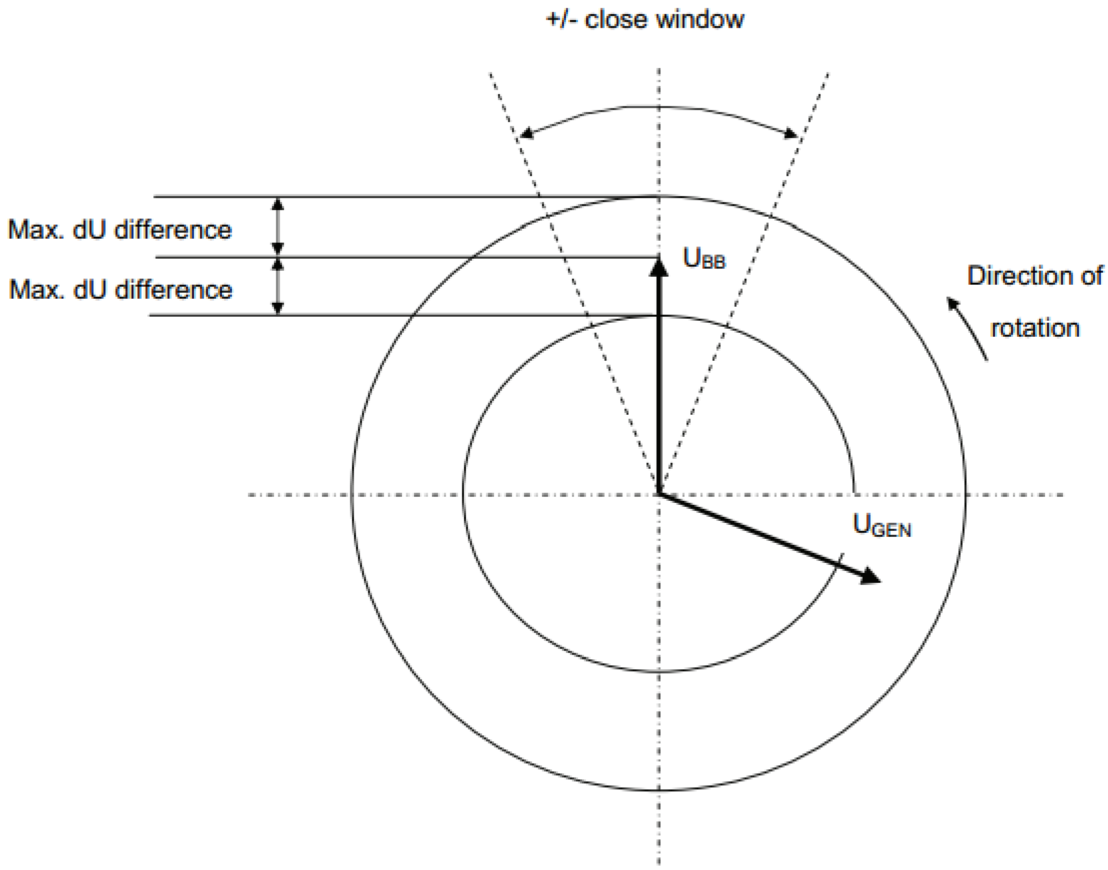
When the static synchronisation is used and the synchronising is activated, the frequency controller will bring the turbine frequency towards the busbar frequency. When the turbine frequency is within 50mHz of the busbar frequency, then the phase controller takes over. This controller uses the angle difference between the turbinesystem 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.

Close signal

The close signal will be issued when phase L1 of the synchronising turbineis 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 UGENL1-UBBL1 is within the adjusted setpoint. 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 **2020 Synchronisation**. Depends if it is the GB or the MB, which is to be synchronised.

Load picture after synchronisation

The synchronised turbine 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 unit will change the controller setpoint according to the requirements of the selected turbine mode.

Static synchronisation is recommended where a slip frequency is not accepted, for instance if several turbines synchronise to a busbar with no load groups connected.

Static and dynamic synchronisation can be switched by using M-logic.

Settings

The following settings must be adjusted, if the static synchroniser is selected:

Setting	Description	Comment
Maximum df	The maximum allowed frequency difference between the busbar/mains and the generator.	+/- value
Maximum dU	The maximum allowed voltage difference between the busbar/mains and the generator.	+/- value, related to the nominal turbinevoltage.
Close window	The maximum allowed voltage difference between the busbar/mains and the generator.	+/- value.
Phase KP	Adjustment of the proportional factor of the PI phase controller.	+/- value.
Phase KI	Adjustment of the integral factor of the PI phase controller.	

13.PID controller

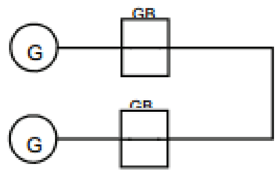
The unit controller is a PID controller. It consists of a proportional regulator, an integral regulator and a differential regulator. The PID controller is able to eliminate the regulation deviation and can easily be tuned in.

Controllers

There are three controllers for the governor control and, if option D1 is selected, also three controllers for the AVR control.

Controller	GOV	AVR	Comment
Frequency	X		Controls the frequency
Power	X		Controls the power
P load sharing	X		Controls the active power load sharing
Voltage (option D1)		X	Controls the voltage
VAr (option D1)		X	Controls the power factor
sharing (option D1)	X	X	Controls the reactive power load sharing

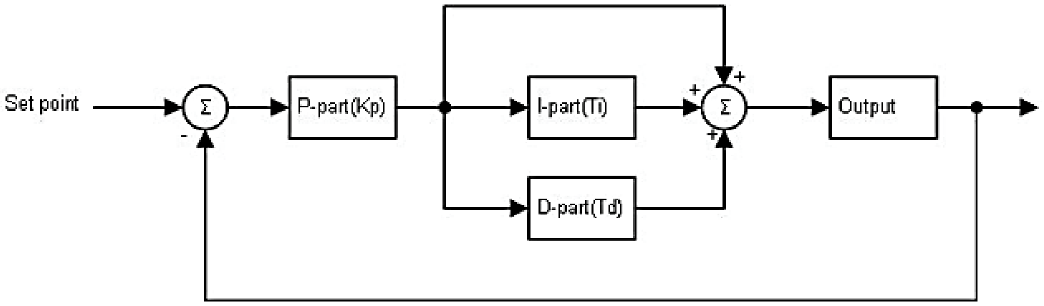
The table below indicates when each of the controllers is active. This means that the controllers can be tuned in when the shown running situations are present.

Governor			AVR (option dependent)			Schematic
Frequency	**Power**	**P LS**	**Voltage**	**VAr**	**Q LS**	
X			X			
X			X			
	X			X		
		X			X	

Load sharing mode is option dependent (option G3/G5)

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.

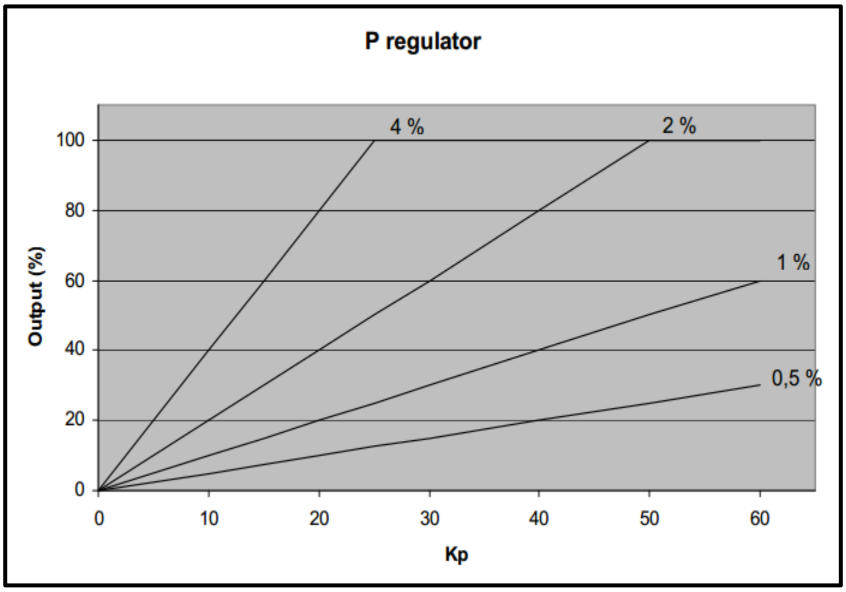
The adjustable settings for the PID controllers in the AGC unit are:
Kp: The gain for the proportional part.
Ti: The integral action time for the integral part.
Td: The differential action time for the differential part.

The function of each part is described in the following.

Proportional regulator

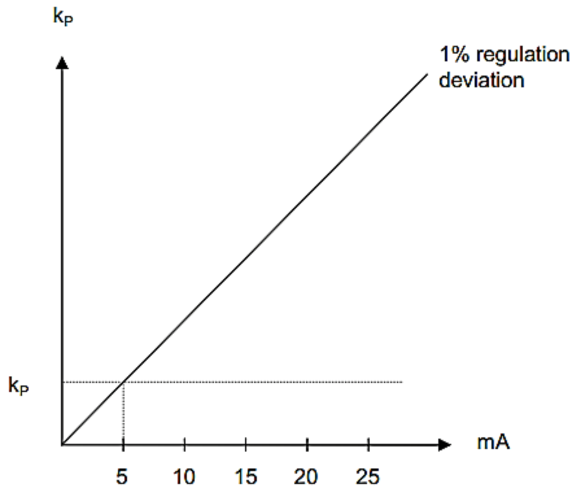
When the regulation deviation occurs, the proportional part will cause an immediate change of the output. The size of the change depends on the gain Kp.

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.



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.

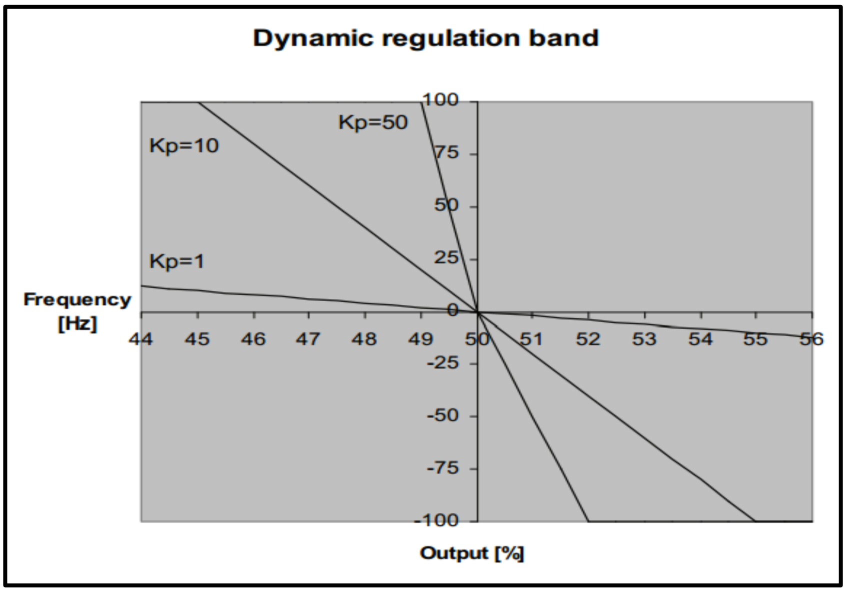


A 1% regulation deviation occurs. With the Kp setting adjusted, the deviation causes the output to change 5mA. The table shows that the output of the AGC changes relatively much, if the maximum speed range is low.

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

Dynamic regulation area

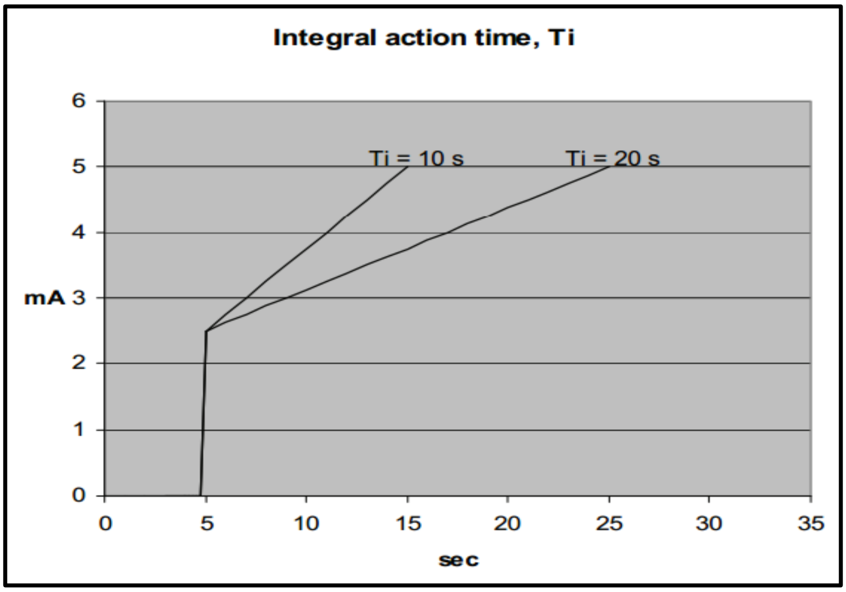
The drawing below shows the dynamic regulation area at given values of Kp. The dynamic area gets smaller, if the Kp is adjusted to a higher value.



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 2.5mA. The integral action time is then measured when the output reaches 2 x 2.5mA = 5mA.



As seen on the drawing the output reaches 5mA 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.

If the Ti is adjusted to 0 s, the I-regulator is switched OFF.

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.

Differential regulator

The main purpose of the differential 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.

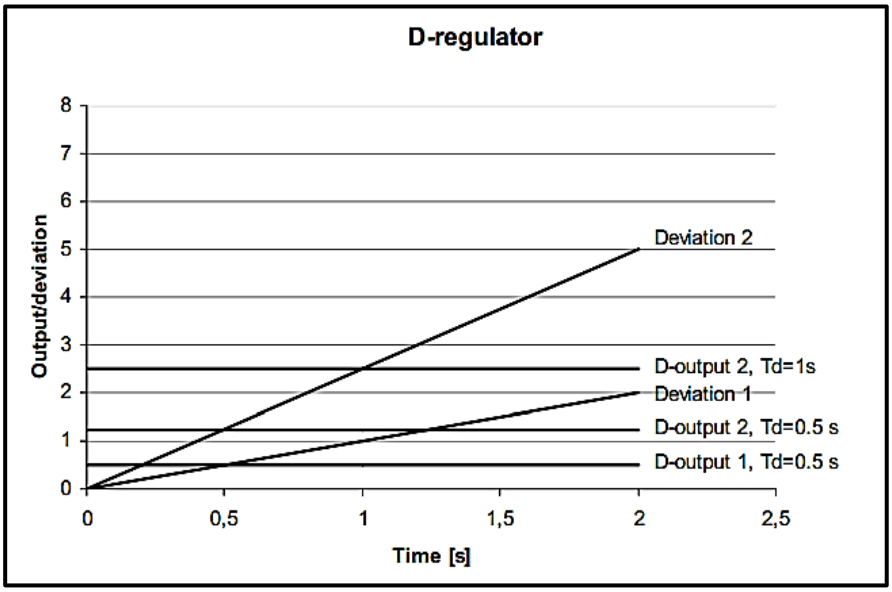
In most cases, the differential regulator is not needed; however in case of very precise regulation situations, e.g. static synchronisation, it can be very useful.

The output from the D-regulator can be explained with the equation: D=Td ·Kp· 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.

When commissioning, please keep in mind that the Kp setting has influence on the D-regulator output.

If the Td is adjusted to 0 s, the D-regulator is switched OFF.

The differential action time Td, must not be too high. This will make the regulation hunt similar to a too high proportional action factor, Kp.

Load share controller/VAr share controller

The load share controller and VAr share controller is used in the AGC whenever load sharing/VAr sharing mode is activated. The controller is a PID controller similar to the other controllers in the system, and it handles frequency control as well as power control (load sharing) and voltage as well as reactive power control (VAr sharing).

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

VAr share controller
Adjustment of the VAr share controller is done in menu 2660 (analogue control) or 2700 (relay control).

General
The primary purpose of the PID controllers is always frequency/voltage control because they are variable in a load sharing system, as well as the power/reactive power on the individual generator. Since the load sharing system requires power/reactive power regulation as well, the PID controllers can be affected by the power/reactive power regulator. For this purpose, a so called weight factor is used (P WEIGHT/Q WEIGHT).

The regulation deviation from the power/reactive power regulator can therefore have great or less influence on the PID controller. An adjustment of 0% means that the power/reactive power control is switched off. An adjustment of 100% means that the power/reactive 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/reactive 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/voltage deviation and a power/reactive power deviation exist, then hunting could be experienced. To avoid this, you can decrease either the weight factor or the parameters of the frequency/voltage regulator.

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

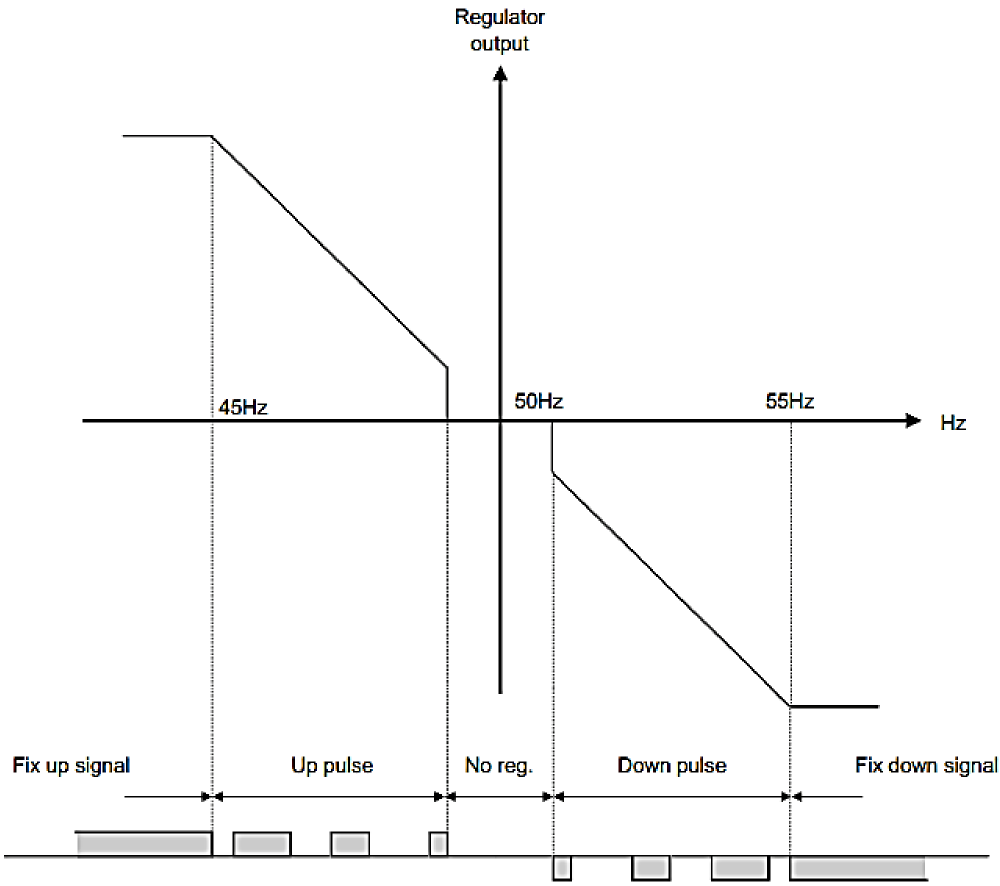
When dynamic synchronising is used the controller '2050 fSYNC controller' is used during the entire synchronising sequence. One of the advantages of dynamic synchronising is that it is relatively fast. In order to improve the speed of the synchronising further, the turbinewill be speeded up between the points of synchronisation (12 o'clock to 12 o'clock) of the two systems. (normally a slip frequency of 0.1Hz 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 fSYNC controller' is activated and the turbinefrequency 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').

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 constantly 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.
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 constantly activated because of the size of the regulation deviation.

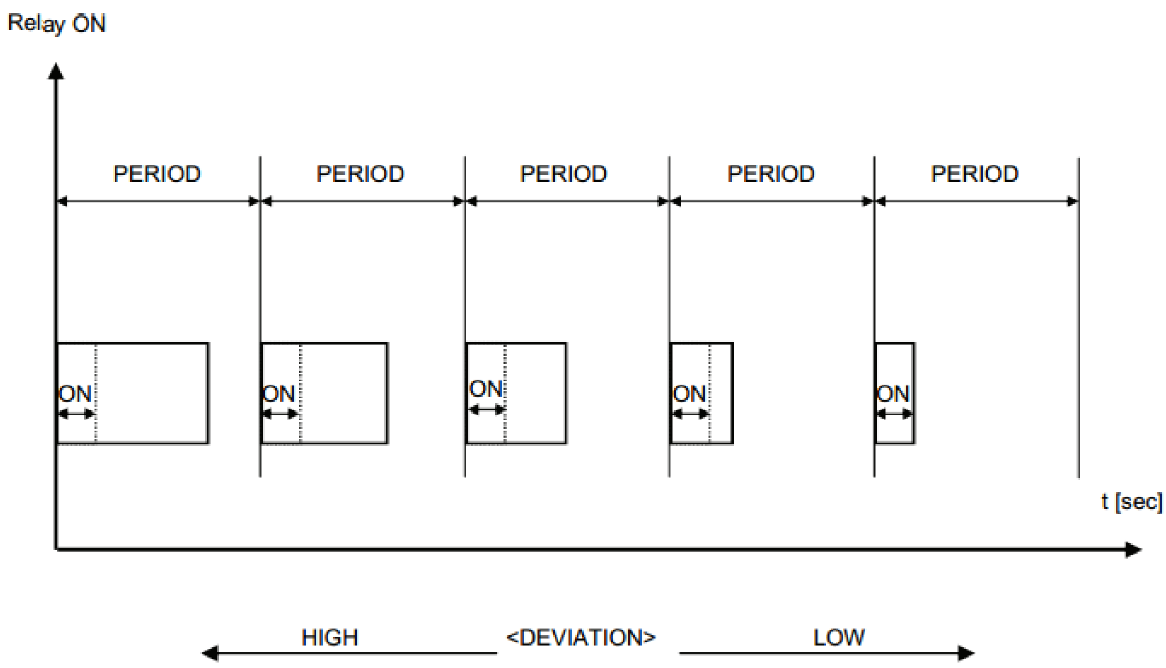
As the drawing indicates, the relays will be fixed ON if the regulation deviation is big, and they will be pulsing if it is closer to the setpoint. In the dynamic range the pulses get shorter and shorter when the regulation deviation gets smaller. Just before the dead band area the pulse is as short 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 (45Hz in the example above).

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 on the drawing below.

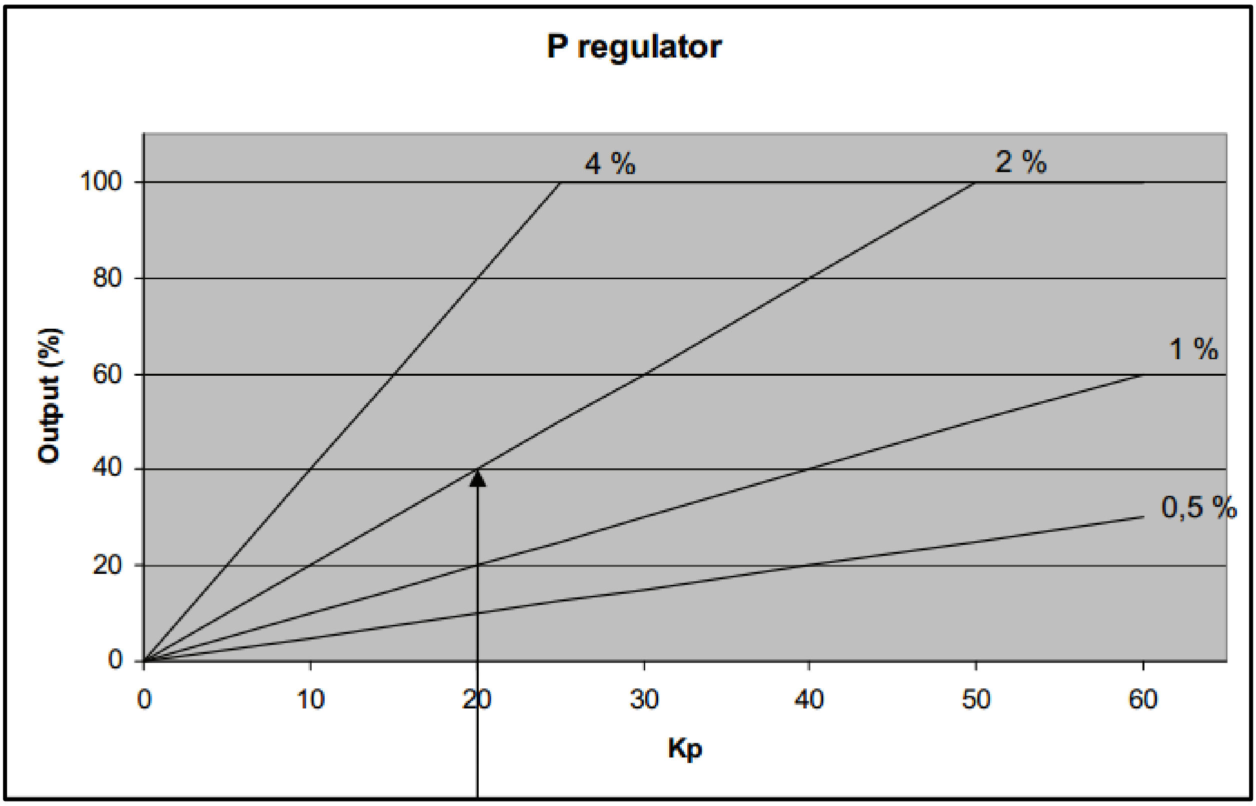
Adjustment	Description	Comment
Period time	Maximum relay time	The time between the beginnings of two subsequent relay pulses.
ON time	Minimum relay time	The minimum length of the relay pulse. The relays will never be activated for a shorter time than the ON time.

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.



Signal length

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



In this example we have a 2 percent regulation deviation and an adjusted value of the Kp = 20. The calculated regulator value of the unit is 40%. Now the pulse length can be calculated with a period time = 2500 ms:

$$e_{DEVIATION} / 100 * t_{PERIOD}$$

$$40 / 100 * 2500 = 1000 ms$$

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

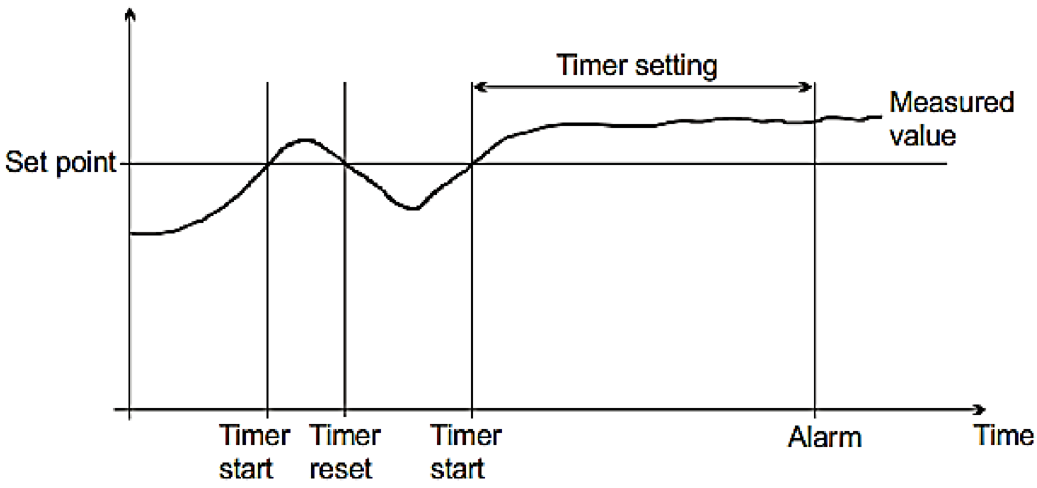
14.Protections

Protections	No. of	ANSI
Reverse power	x2	32R
Short circuit	x2	50P
Overcurrent	x4	51
Voltage-dependent overcurrent	x1	51V
Overvoltage	x2	59P
Undervoltage	x3	27P
Overfrequency	x3	81O
Underfrequency	x3	81U
Unbalanced voltage	x1	47
Unbalanced current	x1	46
Underexcitation or VAr import	x1	32RV
Overexcitation or VAr import	x1	32FV
Overload	x5	32F
Busbar/mains overvoltage	x3	59P
Busbar/mains undervoltage	x4	27P
Load shed, three levels **via current** **via busbar frequency** **via overload** **via fast overload**	x3 x3 x3 x3	51 81 32 32
Busbar/mains overfrequency	x3	81O
Multi-config. inputs with wire,break alarms, three inputs	x2	NA
Emergency stop	x1	1
Overspeed	x2	12
Low auxiliary supply	x1	27DC
High auxiliary supply	x1	81DC
TG breaker external trip	x1	5
Tie/mains breaker external trip	x1	5
Synchronisation failure alarms		25
Breaker open failure		52BF
Breaker close failure		52BF
Breaker position failure		52BF
Close before excitation failure	x1	48
Phase sequence error	x1	47

General

The protections are all of the definite time type, i.e. a setpoint and time is selected.

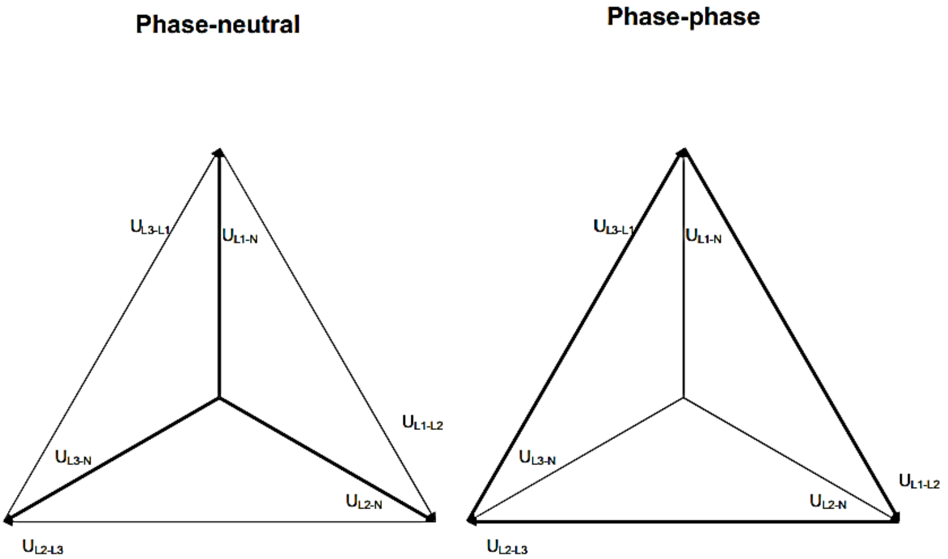
If the function is e.g. overvoltage, the timer will be activated if the setpoint is exceeded. If the voltage value falls below the setpoint value before the timer runs out, then the timer will be stopped and reset.



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

Phase-neutral voltage trip

If the voltage alarms are to work based on phase-neutral measurements, please adjust menus1200 and 1340 accordingly. Depending on the selections, either phase-phase voltages or phase-neutral voltages will be used for the alarm monitoring.



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% undervoltage 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 setpoint is 10% in both cases.

Example

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

Example:

UNOM = 400/230V AC

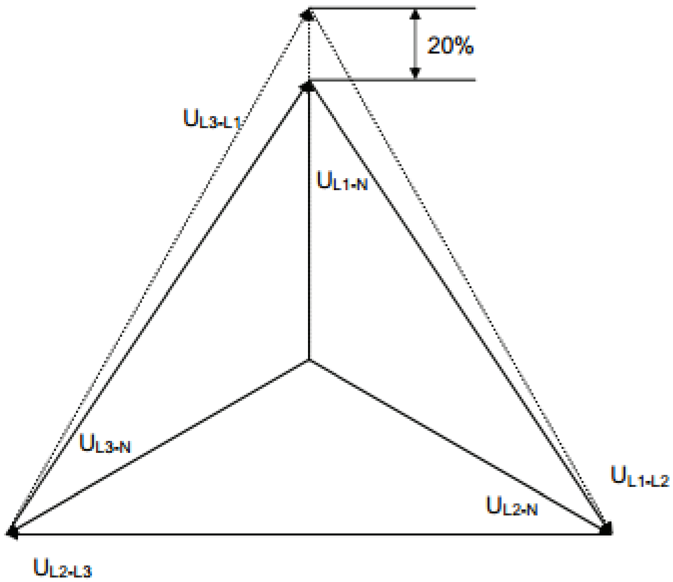
Error situation:

UL1L2 = 360V AC

UL3L1 = 360V AC

UL1-N = 185V AC

ΔUPH-N = 20%



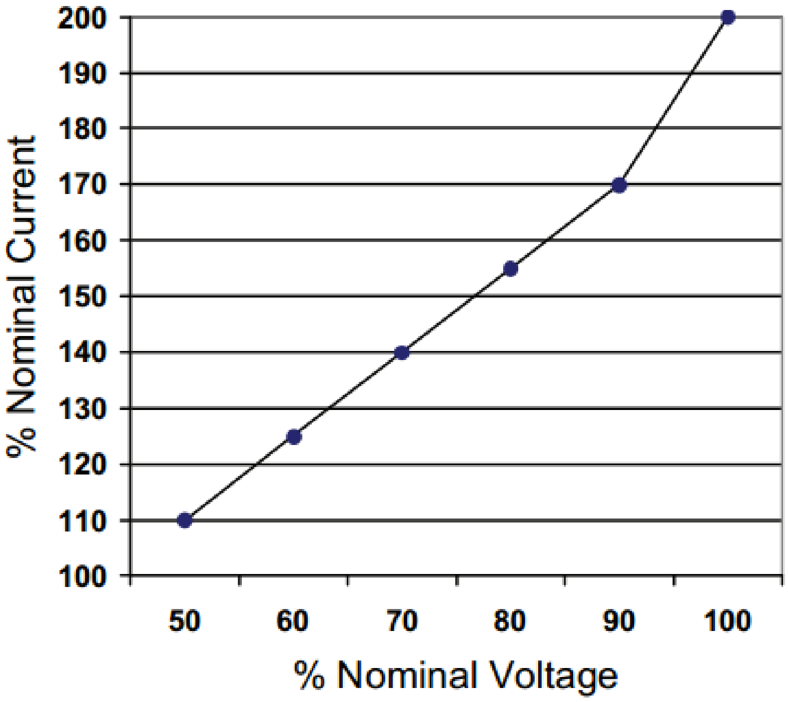
Phase-neutral or phase-phase: both the turbine protections and the busbar/mains protections use the selected voltage.

Voltage-dependent (restraint) overcurrent

This protection is used when the turbine must be tripped due to a fault situation that creates a reduced turbine voltage, e.g. a voltage collapse. During the voltage collapse, the turbine 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 overcurrent setpoint as a function of the measured voltage on the turbine 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 overcurrent setpoint will also drop.



The voltage values for the 6 points on the curve are fixed; the current values can be adjusted in the range 50-200%

Voltage and current % values refer to the nominal settings.

Timer value can be adjusted in the range 0.1- 60.0 sec.

15. Modbus Communication

15.1 Modbus RTU, RS485

Modbus RTU, RS485 communication is available in the device if H2 option is present.

Terminal Description

Term.	Function	Description
29	DATA + (A)	**Modbus RTU, RS485**
30	GND	
31	DATA - (B)	
32		
33	DATA + (A)	
34		
35	DATA - (B)	
36		

Hardware Settings

These are the RS485 hardware settings:

a. 9600 or 19200 bps
b. 8 data bits
c. None parity
d. 1 stop bit
e. No flow control

15.2 Modbus TCP-IP

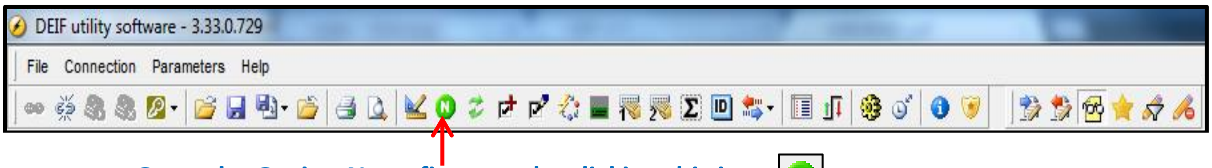
Modbus TCP-IP communication is available in the device if N5 option is present.

The Ethernet port of the Multi-line 2 option N board is delivered pre-configured with these network settings:

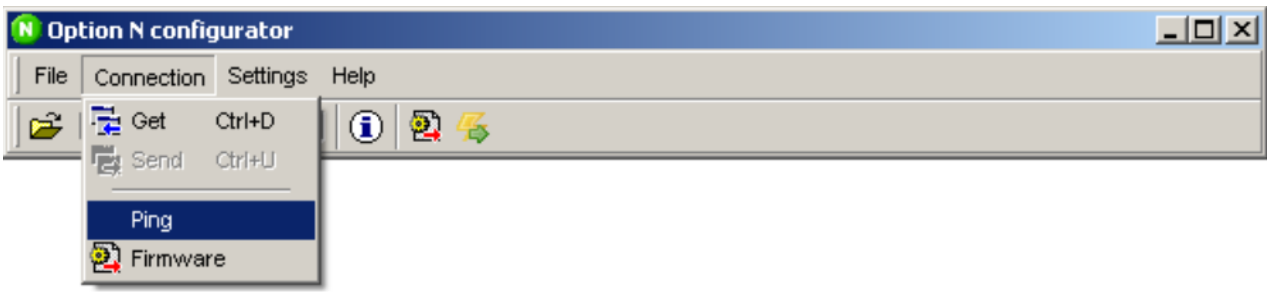
	Factory setting
IP address	192.168.2.21
Subnet mask	255.255.255.0

Please note that the N option network parameters cannot be programmed by using the Multi-line 2 unit display. The PC must be configured to use the same network as specified above.

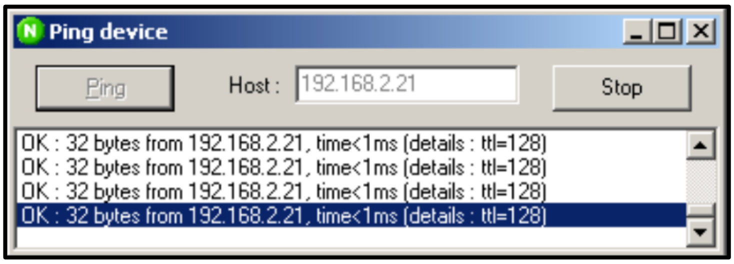
To be able to configure and use the option N, it must be connected directly to a PC.



Open the Option N-configurator by clicking this icon

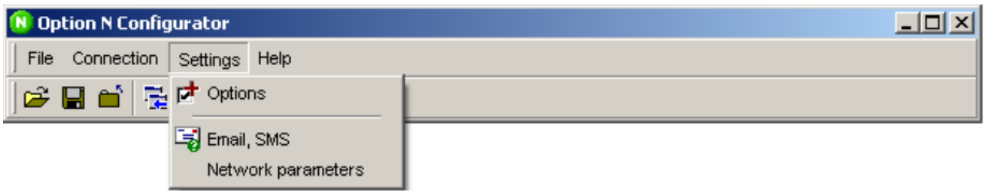


Enter the right IP address and press the ‘Ping’ button (see example below).

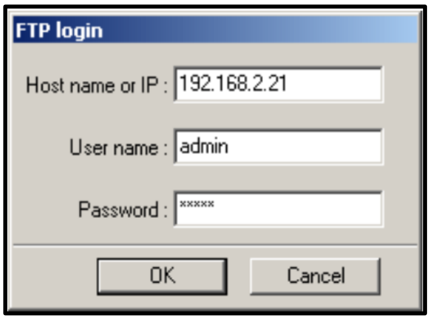


Modifying the network configuration from the option N configuration software

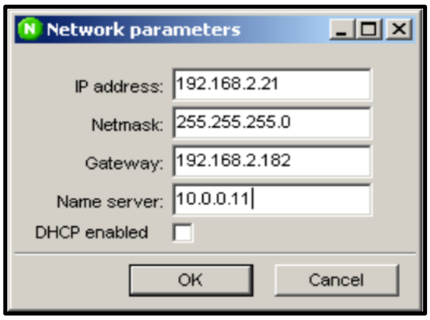
When the option N configuration software is running, it is also possible to modify the option N network parameters (IP address, subnet mask, etc.). This can be done using the menus ‘Settings’ and ‘Network parameters’, see below.



Please note that the ‘Network parameters’ menu point is only available after the ‘Get’ function in the ‘Connection’ menu has been used. The default user name and password are both ‘admin’ (see the below screen dump).

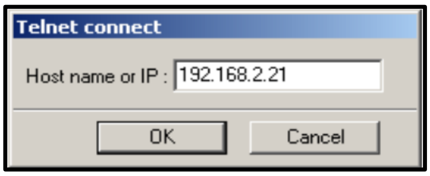


The below parameters are read, and they can be modified here:



DHCP is a new feature in version 2.xx.x of the N option card. When the DHCP function is enabled, the network parameters will be retrieved automatically if a DHCP server is available in the local network. If no DHCP server is available, the network parameters will fall back to factory settings.

Press the ‘OK’ button to write the new configuration to the Multi-line 2 unit.



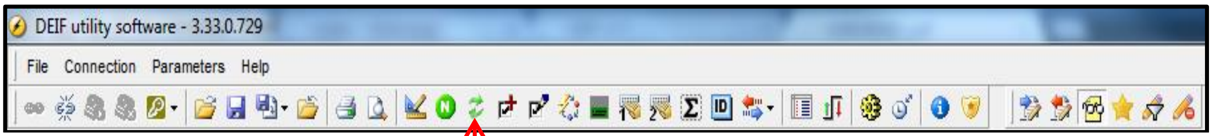
After pressing ‘OK’, the N option reboots automatically. It will take two minutes before the unit is fully operational again.

15.3 Modbus Configurator

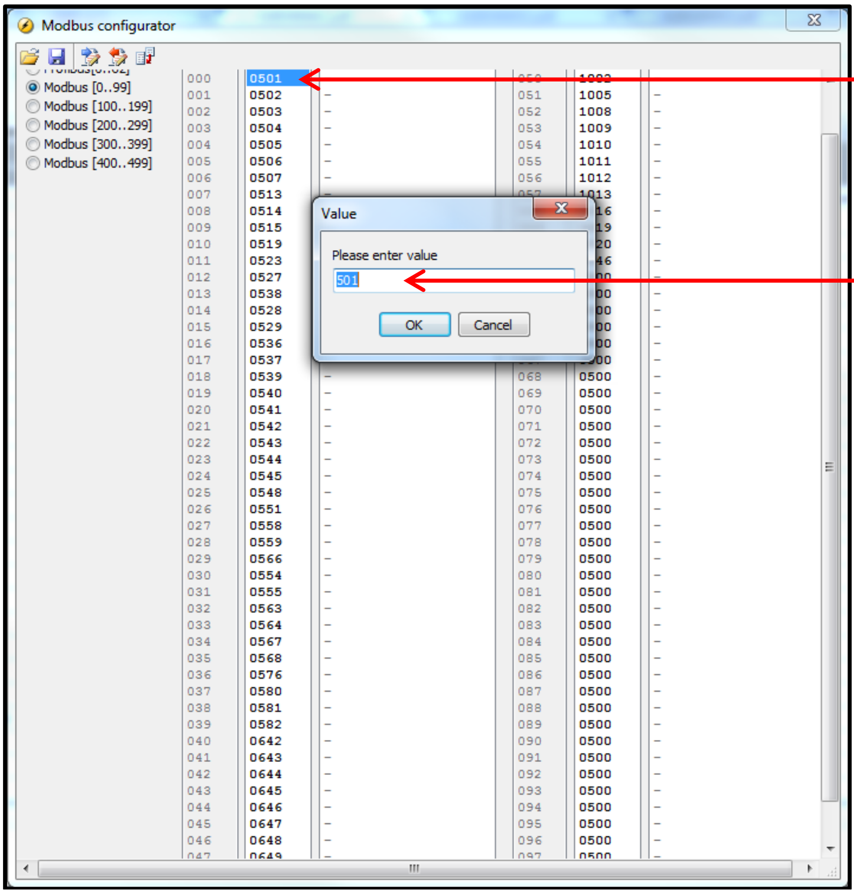
Modbus configurator is a tool available with Utility Software used to Map the relevant electrical data in a sequential Register starting from 000 -499, so that the third party device can fetch the data in minimum Modbus request so as to maximize the communication speed.

Example:

REG	Value	Description
000	501	Turbine voltage L1-L2 [V]
001	502	Turbine voltage L2-L3 [V]
⋮		
499	545	BB FL1 [Hz/100]



Open the Modbus-Configurator by clicking this icon



Click the Register to Map

Enter the address of data at selected register

15.4 Modbus Register table

15.4.1 Measurement table (read only) (function code 04h)

Address	Content		AGC 4 Gen	AGC 4 Mains	AGC 4 BTB
501	U_{L1-L2}	Turbinevoltage L1-L2 [V]	X		
	U_{L1-L2}	Mains voltage L1-L2 [V]		X	
	U_{L1-L2}	Bus A voltage L1-L2 [V]			X
502	U_{L2-L3}	Turbinevoltage L2-L3 [V]	X		
	U_{L2-L3}	Mains voltage L2-L3 [V]		X	
	U_{L2-L3}	Bus A voltage L2-L3 [V]			X
503	U_{L3-L1}	Turbinevoltage L3-L1 [V]	X		
	U_{L3-L1}	Mains voltage L3-L1 [V]		X	
	U_{L3-L1}	Bus A voltage L3-L1 [V]			X
504	U_{L1-N}	Turbinevoltage L1-N [V]	X		
	U_{L1-N}	Mains voltage L1-N [V]		X	
	U_{L1-N}	Bus A voltage L1-N [V]			X
505	U_{L2-N}	Turbinevoltage L2-N [V]	X		
	U_{L2-N}	Mains voltage L2-N [V]		X	
	U_{L2-N}	Bus A voltage L2-N [V]			X
506	U_{L3-N}	Turbinevoltage L3-N [V]	X		
	U_{L3-N}	Mains voltage L3-N [V]		X	
	U_{L3-N}	Bus A voltage L3-N [V]			X
507	f_{L1}	Turbinef L1 [Hz/100]	X		
	f_{L1}	Mains f L1 [Hz/100]		X	
	f_{L1}	Bus A f L1 [Hz/100]			X
508	f_{L2}	Turbinef L2 [Hz/100]	X		
	f_{L2}	Mains f L2 [Hz/100]		X	
	f_{L2}	Bus A f L2 [Hz/100]			X
509	f_{L3}	Turbinef L3 [Hz/100]	X		
	f_{L3}	Mains f L3 [Hz/100]		X	
	f_{L3}	Bus A f L3 [Hz/100]			X
510	Phi	U gen. phase angle L1-L2 [Deg/10]	X		
	Phi	U mains phase angle L1-L2 [Deg/10]		X	
	Phi	U BA phase angle L1-L2 [Deg/10]			X
	Phi	U SC phase angle L1-L2 [Deg/10]			
511	Phi	U gen. phase angle L2-L3 [Deg/10]	X		
	Phi	U mains phase angle L2-L3 [Deg/10]		X	
	Phi	U BA phase angle L2-L3 [Deg/10]			X
	Phi	U SC phase angle L2-L3 [Deg/10]			
512	Phi	U gen. phase angle L3-L1 [Deg/10]	X		
	Phi	U mains phase angle L3-L1 [Deg/10]		X	
	Phi	U BA phase angle L3-L1 [Deg/10]			X
513	I_{L1}	Turbinecurrent L1 [A]	X		
	I_{L1}	Mains current L1 [A]		X	

		IL1	Bus A current L1 [A]			X
514		IL2	Turbine current L2 [A]	X		
		IL2	Mains current L2 [A]		X	
		IL2	Bus A current L2 [A]			X
515		IL3	Turbine current L3 [A]	X		
		IL3	Mains current L3 [A]		X	
		IL3	Bus A current L3 [A]			X
516		PGEN L1	Turbine power L1 [kW]	X		
		PMAINS L1	Mains power L1 [kW]		X	
		PBA L1	Bus A power L1 [kW]			X
517		PGEN L2	Turbine power L2 [kW]	X		
		PMAINS L2	Mains power L2 [kW]		X	
		PBA L2	Bus A power L2 [kW]			X
518		PGEN L3	Turbine power L3 [kW]	X		
		PMAINS L3	Mains power L3 [kW]		X	
		PBA L3	Bus A power L3 [kW]			X
519		PGEN	Turbine power [kW]	X		
		PMAINS	Mains power [kW]		X	
		PBA	Bus A power [kW]			X
520		QGEN L1	Turbine reactive power L1 [kVAr]	X		
		QMAINS L1	Mains reactive power L1 [kVAr]		X	
		QBA L1	Bus A reactive power L1 [kVAr]			X
521		QGEN L2	Turbine reactive power L2 [kVAr]	X		
		QMAINS L2	Mains reactive power L2 [kVAr]		X	
		QBA L2	Bus A reactive power L2 [kVAr]			X
522		QGEN L3	Turbine reactive power L3 [kVAr]	X		
		QMAINS L3	Mains reactive power L3 [kVAr]		X	
		QBA L3	Bus A reactive power L3 [kVAr]			X
523		QGEN	Turbine reactive power [kVAr]	X		
		QMAINS	Mains reactive power [kVAr]		X	
		QBA	Bus A reactive power [kVar]			X
524		SGEN L1	Turbine apparent power L1 [kVA]	X		
		SMAINS L1	Mains apparent power L1 [kVA]		X	
		SBA L1	Bus A apparent power L1 [kVA]			X
525		SGEN L2	Turbine apparent power L2 [kVA]	X		
		SMAINS L2	Mains apparent power L2 [kVA]		X	
		SBA L2	Bus A apparent power L2 [kVA]			X
526		SGEN L3	Turbine apparent power L3 [kVA]	X		
		SMAINS L3	Mains apparent power L3 [kVA]		X	
		SBA L3	Bus A apparent power L3 [kVA]			X
527		SGEN	Turbine apparent power [kVA]	X		
		SMAINS	Mains apparent power [kVA]		X	
		SBA	Bus A apparent power [kVA]			X
528	[Hi]	RGEN	Reactive energy counter [kVArh]	X		
529	[Lo]					

528	[Hi]	R_{MAINS}	Reactive energy counter [kVArh]		X	
529	[Lo]					
528	[Hi]	R_{BA}	Reactive energy counter [kVArh]			X
529	[Lo]					
530	[Hi]	E_{GEN}	Active energy counter, day [kWh]	X		
531	[Lo]					
530	[Hi]	E_{MAINS}	Active energy counter, day [kWh]		X	
531	[Lo]					
530	[Hi]	E_{BA}	Active energy counter, day [kWh]			X
531	[Lo]					
532	[Hi]	E_{GEN}	Active energy counter, week [kWh]	X		
533	[Lo]					
532	[Hi]	E_{MAINS}	Active energy counter, week [kWh]		X	
533	[Lo]					
532	[Hi]	E_{BA}	Active energy counter, week [kWh]			X
533	[Lo]					
534	[Hi]	E_{GEN}	Active energy counter, month [kWh]	X		
535	[Lo]					
534	[Hi]	E_{MAINS}	Active energy counter, month [kWh]		X	
535	[Lo]					
534	[Hi]	E_{BA}	Active energy counter, month [kWh]			X
535	[Lo]					
536	[Hi]	E_{GEN}	Active energy counter, total [kWh]	X		
537	[Lo]					
536	[Hi]	E_{MAINS}	Active energy counter, total [kWh]		X	
537	[Lo]					
536	[Hi]	E_{BA}	Active energy counter, total [kWh]			X
537	[Lo]					
538		Cos-phi	Turbine PF [cosPhi/100]	X		
		Cos-phi	Mains PF [cosPhi/100]		X	
		Cos-phi	Bus A PF [cosPhi/100]			X
539		$U_{BBL1-L2}$	U BB L1-L2 [V]	X	X	X
540		$U_{BBL2-L3}$	U BB L2-L3 [V]	X	X	X
541		$U_{BBL3-L1}$	U BB L3-L1 [V]	X	X	X
542		U_{BBL1-N}	U BB L1-N [V]	X	X	X
543		U_{BBL2-N}	U BB L2-N [V]	X	X	X
544		U_{BBL3-N}	U BB L3-N [V]	X	X	X
545		F_{BB}	BB FL1 [Hz/100]	X	X	X
546		F_{BB}	f BB L2 [Hz/100]	X	X	X
547		F_{BB}	f BB L3 [Hz/100]	X	X	X
548		$PHI_{BBL1-L2}$	U BB phase angle L1-L2 [Deg/10]	X	X	X
549		$PHI_{BBL2-L3}$	U BB phase angle L2-L3 [Deg/10]	X	X	X
550		$PHI_{BBL3-L1}$	U BB phase angle L3-L1 [Deg/10]	X	X	X
551		$PHI_{BBL1-DGL1}$	U BB L1 - U GEN L1 phase angle [Deg/10]	X		
		$PHI_{BBL1-ML1}$	U BB L1 - U Mains L1 phase angle [Deg/10]		X	

		$PHI_{BAL1-BBL1}$	U BB A L1 - U BB B L1 phase angle [Deg/10]			X
552		$PHI_{BBL2-DGL2}$	U BB L2 - U GEN L2 phase angle [Deg/10]	X		
		$PHI_{BBL2-MAINSL2}$	U BB L2 - U mains L2 phase angle [Deg/10]		X	
		$PHI_{BBL2-BAL2}$	U BB L2 - U bus A L2 phase angle [Deg/10]			X
553		$PHI_{BBL3-DGL3}$	U BB L3 - U GEN L3 phase angle [Deg/10]	X		
		$PHI_{BBL3-MAINSL3}$	U BB L3 - U mains L3 phase angle [Deg/10]		X	
		$PHI_{BBL3-BAL3}$	U BB L3 - U bus A L3 phase angle [Deg/10]			X
554	[Hi]	Abs. run. hours	Absolute. run hours	X		
555	[Lo]					
556	[Hi]	Rel.. run. hours	Relative. run hours	X		
557	[Lo]					
558		Alarms	No. of alarms	X	X	X
559		Alarms	No. of unack. alarms	X	X	X
560		Alarms	No. of active acknowledged alarms	X	X	X
561		Run. min.	Running min. counter, shutdown override	X		
562		Run. hours	Running hour counter, shutdown override	X		
563		GB_{oper}	No. of GB operations	X		
		TB_{oper}	No. of TB operations		X	
		BTB_{oper}	No. of BTB operations			X
564		MB_{oper}	No. of MB operations	X	X	
567		U_{SUPPLY}	DC supply term. 1-2 [V/10]	X	X	X
568		$U_{SUPPLY\ M4}$	DC supply term. 98-99 [V/10]	X	X	X
569		Service	Service timer 1 run. hours	X		
570		Service	Service timer 1 run. days	X		
571		Service	Service timer 2 run. hours	X		
572		Service	Service timer 2 run. days	X		
576		RPM	RPM	X		
580			Multi-input 102 unscaled	X	X	X
581			Multi-input 105 unscaled	X	X	X
582			Multi-input 108 unscaled	X	X	X
583			Multi-input 102 scaled	X	X	X
584			Multi-input 105 scaled	X	X	X
585			Multi-input 108 scaled	X	X	X
586		Ain	4-20mA input, scaled	91	91	91
587		Ain	4-20mA input, scaled	93	93	93
588		Ain	4-20mA input, scaled	95	95	95
589		Ain	4-20mA input, scaled	97	97	97
591		P_{BB}	BUS power		105	
		P_{BA}	Bus A			105
592		P_{MAINS}	Mains power [kW]	102	102	
642		RegAddr.	Control register address 0	X	X	X
643		RegAddr.	Control register address 1	X	X	X
644		RegAddr.	Control register address 2	X	X	X
645		RegAddr.	Control register address 3	X	X	X
646		RegAddr.	Control register address 4	X	X	X

647		RegAddr.	Control register address 5	X	X	X
648		RegAddr.	Control register address 6	X	X	X
649		RegAddr.	Control register address 7	X	X	X
650		RegAddr	Control register address 8	X	X	X
651		RegAddr	Control register address 9	X	X	X
652		RegAddr	Control register address 10	X	X	X

15.4.2 Alarm and Status table (read only) (function code 04h)

1000			**Generator/mains/busbar A**			
	0	1000	G -P> 1	X		
			M -P> 1		X	
			BA -P> 1			X
	1	1010	G -P> 2	X		
			M -P> 2		X	
			BA -P> 2			X
			SC -P> 2			
	2	1020	Reserved			
	3	1030	G I> 1	X		
			M I> 1		X	
			BA I> 1			X
			SC I> 1			
	4	1040	G I> 2	X		
			M I> 2		X	
			BA I> 2			X
			SC I> 2			
	5	1050	G I> 3	X		
			M I> 3		X	
			BA I> 3			X
			SC I> 3			
	6	1060	G I> 4	X		
			M I> 4		X	
			BA I> 4			X
			SC I> 4			
	7	1090	G I> inv.			
	8	1110	G Iv>	X	X	X
	9	1130	G I>> 1	X		
			M I>> 1		X	
			BA I>> 1			X
			SC I>> 1			
	10	1140	G I>> 2	X		
			M I>> 2		X	
			BA I>> 2			X
			SC I>> 2			
	11	1150	G U> 1	X		

			M U> 1		X	
			BA U> 1			X
			SC U> 1			
	12	1160	G U> 2	X		
			M U> 2		X	
			BA U> 2			X
			SC U> 2			
	13	1170	G U< 1	X		
			M U< 1		X	
			BA U< 1			X
			SC U< 1			
	14	1180	G U< 2	X		
			M U< 2		X	
			BA U< 2			X
			SC U< 2			
	15	1190	G U< 3	X		
			M U< 3		X	
			BA U< 3			X
			SC U< 3			
1001	0	1210	G f> 1	X		
			M f> 1		X	
			BA f> 1			X
			BA f> 1			
	1	1220	G f> 2	X		
			M f> 2		X	
			BA f> 2			X
			SC f> 2			
	2	1230	G f> 3	X		
			M f> 3		X	
			BA f> 3			X
			SC f> 3			
	3	1240	G f< 1	X		
			M f< 1		X	
			BA f < 1			X
	4	1250	G f< 2	X		
			M f< 2		X	
			BA f< 2			X
			SC f< 2			
	5	1260	G f< 3	X		
			M f< 3		X	
			BA f< 3			X
			SC f< 3			
			BB/mains			
	6	1270	BB U> 1	X	X	X
	7	1280	BB U> 2	X	X	X
	8	1290	BB U> 3	X	X	X

	9	1300	BB U< 1	X	X	X
	10	1310	BB U< 2	X	X	X
	11	1320	BB U< 3	X	X	X
	12	1330	BB U< 4	X	X	X
	13	1350	BB f> 1	X	X	X
	14	1360	BB f> 2	X	X	X
	15	1370	BB f> 3	X	X	X
1002	0	1380	BB f< 1	X	X	X
	1	1390	BB f< 2	X	X	X
	2	1400	BB f< 3	X	X	X
	3	1410	BB f< 4	X	X	X
	4	1420	df/dt (ROCOF)	X	X	X
	5	1430	Vector jump	X	X	X
	6	1440	BB pos. seq. volt. low	X	X	X
			Generator/mains/busbar A			
	7	1450	G P> 1	X		
			M P> 1		X	
			BA P> 1			X
			SC P> 1			
	8	1460	G P> 2	X		
			M P> 2		X	
			BA P> 2			X
			SC P> 2			
	9	1470	G P> 3	X		
			M P> 3		X	
			BA P> 3			X
			SC P> 3			
	10	1480	G P> 4	X		
			M P> 4		X	
			BA P> 4			X
			SC P> 4			
	11	1490	G P> 5	X		
			M P> 5		X	
			BA P> 5			X
			SC P> 5			
	12	1500	Unbalance curr.	X	X	
	13	1510	Unbalance volt.	X	X	
	14	1520	G -Q>	X		
			M -Q>		X	
			BA -Q>			X
			SC -Q>			
	15	1530	G Q>	X		
			M Q>		X	
			BA Q>			X
			SC Q>			
1003			**Generator/busbar**			

	0	1540	Gen. neg. seq. I	X		
			Mains neg. seq. I		X	
	1	1550	Turbineneg. seq. U	X		
			Mains neg. seq. U		X	
			Bus A neg. seq. U			X
	2	1570	Gen. zero seq. I	X		
			Mains zero seq. I		X	
			Bus A zero seq. I			X
	3	1580	Zero seq. U	X		
			Mains zero seq. U		X	
			Bus A zero seq. U			X
			Busbar/mains			
	4	1600	Directional overcurrent 1	X	X	X
	5	1610	Directional overcurrent 2	X	X	X
	6	1620	BB unbalance U	X	X	X
	7	1800	NEL 1 I>	X	X	
	8	1810	NEL 2 I>	X	X	
	9	1820	NEL 3 I>	X	X	
	10	1830	NEL 1 BB f<	X	X	
	11	1840	NEL 2 BB f<	X	X	
	12	1850	NEL 3 BB f<	X	X	
	13	1860	NEL 1 P>	X	X	
	14	1870	NEL 2 P>	X	X	
	15	1880	NEL 3 P>	X	X	
1004	0	1890	NEL 1 P>>	X	X	
	1	1900	NEL 2 P>>	X	X	
	2	1910	NEL 3 P>>	X	X	
	3	1930	DG/SG max. parallel time			
	4	1940	DG/SC max. parallel time			
	5	1950	EDG/MSB max. parallel time			
	6	1960	Uq< 1			
	7	1970	Uq< 2			
	8	1980	GB ext. trip			
	9	1980	MB ext. trip			
	10	1650	Ut< 1 monitoring active			
	11	1660	Ut< 1			
	12	1690	Ut< 2 monitoring active			
	13	1700	Ut< 2			
	14	1760	G P dep. Q<			
	15	1790	G P dep. Q>			
1005			**Synchronising**			
	0	2120	Synchronising window	X	X	X
	1	2130	Synchronising failure GB	X		
			Synchronising failure TB		X	
			Synchronising failure BTB			X
	2	2140	Synchronising failure MB	X	X	

			Synchronising failure SGB			
			Synchronising failure SCB			
			Synchronising failure TB			
	3	2150	Phase seq. failure	X	X	X
			GB open failure	X		
	4	2160	TB open failure		X	
			BTB open failure			X
			GB close failure	X		
	5	2170	TB close failure		X	
			BTB close failure			X
			GB pos. failure	X		
	6	2180	TB pos. failure		X	
			BTB pos. failure			X
			MB open failure	X	X	
	7	2200	SGB open failure			
			SCB open failure			
			TB open failure			
			MB close failure	X	X	
	8	2210	SGB close failure			
			SCB close failure			
			TB close failure			
			MB pos. failure	X	X	
	9	2220	SGB pos. failure			
			SCB pos. failure			
			TB pos. failure			
	10	2270	Close before excitation failure	X		
	11	2190	Vector mismatch			
			Regulation			
	0	2560	GOVERNOR regulation fail.	X		
	1	2630	Deload error	X		
	2	2680	AVR regulation fail.	X		
1006	3	2960	P loadshare fail.			
	4	2970	Q loadshare fail.			
	5	2730	GOV mode undef.			
	6	2750	AVR mode undef.			
			Digital alarms			
	0	3000	Digital alarm input	23	23	23
	1	3010	Digital alarm input	24	24	24
	2	3020	Digital alarm input	25	25	25
	3	3030	Digital alarm input	26	26	26
1007	4	3040	Digital alarm input	27	27	27
	5	3050	Digital alarm input			
	6	3060	Digital alarm input	29	29	29
	7	3070	Digital alarm input	30	30	30
	8	3080	Digital alarm input	31	31	31
	9	3090	Digital alarm input	32	32	32

	10	3100	Digital alarm input	33	33	33
	11	3110	Digital alarm input	34	34	34
	12	3120	Digital alarm input	35	35	35
	13					
	14					
	15					
1008	0	3130	Digital alarm input	43	43	43
	1	3140	Digital alarm input	44	44	44
	2	3150	Digital alarm input	45	45	45
	3	3160	Digital alarm input	46	46	46
	4	3170	Digital alarm input	47	47	47
	5	3180	Digital alarm input	48	48	48
	6	3190	Digital alarm input	49	49	49
	7	3200	Digital alarm input	50	50	50
	8	3210	Digital alarm input	51	51	51
	9	3220	Digital alarm input	52	52	52
	10	3230	Digital alarm input	53	53	53
	11	3240	Digital alarm input	54	54	54
	12	3250	Digital alarm input	55	55	55

15.4.3 Status Flag table (Read Only) (Function code 02h)

AGC 4 Gen:-

100001	GB position ON
100002	MB position ON
100003	
100004	Running
100005	Turbinevoltage/ frequency OK
100006	Mains failure/ main busbar failure
100007	
100008	
100009	
100010	
100011	
100012	
100013	
100014	Island
100015	AMF
100016	Peak Shaving
100017	Fixed Power
100018	Mains Power Export
100019	Load Take Over (LTO)
100020	Power Management
100021	Any alarm TG1
100022	Any alarm TG2
100023	Any alarm TG3
100024	Any alarm TG4
100025	Any alarm TG5
100026	Any alarm TG6
100027	Any alarm TG7
100028	Any alarm TG8

22529	Digital Input 43
22530	Digital Input 44
22531	Digital Input 45
22532	Digital Input 46
22533	Digital Input 47
22534	Digital Input 48
22535	Digital Input 49
22536	Digital Input 50
22537	Digital Input 51
22538	Digital Input 52
22539	Digital Input 53
22540	Digital Input 54
22541	Digital Input 55
22542	Digital Input 23
22543	Digital Input 24
22544	Digital Input 25
22545	Digital Input 26
22546	Digital Input 27

22584	Emergency Stop
22585	Digital Input 117
22586	Digital Input 108
22587	Digital Input 116
22588	Digital Input 114
22589	Digital Input 113
22590	Digital Input 112
22591	
22592	Multi Input 108 Cable fail
22593	Multi Input 105 Cable fail
22594	Multi Input 102 Cable fail

AGC 4 BTB:-

100001	BTB position ON
100002	
100003	
100004	
100005	
100006	
100007	
100008	
100009	
100010	
100011	
100012	
100013	
100014	
100015	
100016	
100017	
100018	
100019	
100020	Power Management
100021	Any alarm DG1
100022	Any alarm DG2
100023	Any alarm DG3
100024	Any alarm DG4
100025	Any alarm DG5
100026	Any alarm DG6
100027	Any alarm DG7
100028	Any alarm DG8

22529	Digital Input 43
22530	Digital Input 44
22531	Digital Input 45
22532	Digital Input 46
22533	Digital Input 47
22534	Digital Input 48
22535	Digital Input 49
22536	Digital Input 50
22537	Digital Input 51
22538	Digital Input 52
22539	Digital Input 53
22540	Digital Input 54
22541	Digital Input 55
22542	Digital Input 23
22543	Digital Input 24
22544	Digital Input 25
22545	Digital Input 26
22546	Digital Input 27

22584	Emergency Stop
22585	Digital Input 117
22586	Digital Input 108
22587	Digital Input 116
22588	Digital Input 114
22589	Digital Input 113
22590	Digital Input 112
22591	
22592	Multi Input 108 Cable fail
22593	Multi Input 105 Cable fail
22594	Multi Input 102 Cable fail

AGC 4 Mains:-

100001	TB position ON
100002	MB position ON
100003	
100004	
100005	
100006	Mains failure/main busbar failure
100007	
100008	
100009	
100010	
100011	Test Mode
100012	
100013	
100014	Island
100015	AMF
100016	Peak Shaving
100017	Fixed Power
100018	Mains Power Export
100019	Load Take Over (LTO)
100020	
100021	Any alarm TG1
100022	Any alarm TG2
100023	Any alarm TG3
100024	Any alarm TG4
100025	Any alarm TG5
100026	Any alarm TG6
100027	Any alarm TG7
100028	Any alarm TG8

22529	Digital Input 43
22530	Digital Input 44
22531	Digital Input 45
22532	Digital Input 46
22533	Digital Input 47
22534	Digital Input 48
22535	Digital Input 49
22536	Digital Input 50
22537	Digital Input 51
22538	Digital Input 52
22539	Digital Input 53
22540	Digital Input 54
22541	Digital Input 55
22542	Digital Input 23
22543	Digital Input 24
22544	Digital Input 25
22545	Digital Input 26
22546	Digital Input 27

22584	Emergency Stop
22585	Digital Input 117
22586	Digital Input 108
22587	Digital Input 116
22588	Digital Input 114
22589	Digital Input 113
22590	Digital Input 112
22591	
22592	Multi Input 108 Cable fail
22593	Multi Input 105 Cable fail
22594	Multi Input 102 Cable fail

16. Case Studies

Case 1

There is a plant with 1 Mains & 2 Turbine of 10 MW, if plant mode is fixed power & both turbines are in power management they will take setpoint from mains in Proportionate, but if 1 Turbine is in fixed Power & other is power management then Mains gives full setpoint to other turbine due to which plant generation increases, if I want that if 1 turbine is fixed then mains should give setpoint other Turbine compensating the load on fixed turbine.

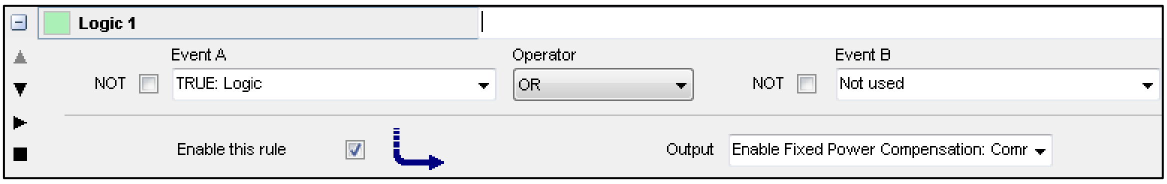
Answer

There are 2 ways, 1 is if you want Mains should not look for Turbine which is fixed power & maintain plant generation as per setpoint from turbine which is in power management in this case total generation will be always more than the setpoint on Mains unit. (This is default functionality)

Example: - Setpoint on mains is 10MW & 1 Turbine is fixed power with 5 MW, Mains will give setpoint to other turbine 10 MW.

Other way is compensation of fixed turbine, in which mains will vary the turbine which is power management so that the total plant generation is as per setpoint in mains.
This can be achieve by activating M-logic command in mains.

Example: - Setpoint on mains is 10MW & 1 Turbine is fixed power with 5 MW, Mains will give setpoint to other turbine 5 MW. So that total generation of plant will be 10 MW.



Case 2

How to give Import/Export setpoint more than 20MW as the limit in Day & Night Saving is - 20000KW to 20000KW

Answer

This could be done by parameter number 7005 in Mains Group

1KW = 1 KW	Set point Entered will Multiplied by 1	Setpoint can be up to 20MW
1KW = 10 KW	Set point Entered will Multiplied by 10	Setpoint can be up to 200MW
1KW = 100 KW	Set point Entered will Multiplied by 100	Setpoint can be up to 2000MW
1KW = 1000 KW	Set point Entered will Multiplied by 1000	Setpoint can be up to 20000MW

Case 3

How to give Fixed Power setpoint more than 20MW as the limit in fixed Power setpoint is - 20000KW to 20000KW

Answer

This could be done by parameter number 7055 in Mains Group

1KW = 1 KW	Set point Entered will Multiplied by 1	Setpoint can be up to 20MW
1KW = 10 KW	Set point Entered will Multiplied by 10	Setpoint can be up to 200MW
1KW = 100 KW	Set point Entered will Multiplied by 100	Setpoint can be up to 2000MW
1KW = 1000 KW	Set point Entered will Multiplied by 1000	Setpoint can be up to 20000MW

Case 3 **How to change the rate of change of setpoint for Fixed/Import/Export setpoint, so that per pulse increases the definite load.**

Answer

This could be done by parameter number 2525.
In AGC 4 Mains this is KW/s & In AGC 4 Gen it is %.
In AGC 4 Mains if you want 100 KW/s then u have to consider the 7005 & 7055 also

1KW = 1 KW	Set point Entered will Multiplied by 1	If 2525 is 100 KW/s then Setpoint will increase 100 KW/s
1KW = 10 KW	Set point Entered will Multiplied by 10	If 2525 is 100 KW/s then Setpoint will increase 1000 KW/s
1KW = 100 KW	Set point Entered will Multiplied by 100	If 2525 is 100 KW/s then Setpoint will increase 10000 KW/s
1KW = 1000 KW	Set point Entered will Multiplied by 1000	If 2525 is 100 KW/s then Setpoint will increase 100000 KW/s

So if you want that want only 100 KW/s then you have to change 2525 as per 7005 & 7055

1KW = 1 KW	2525 will be **100** KW/s
1KW = 10 KW	2525 will be **10** KW/s
1KW = 100 KW	2525 will be **1** KW/s
1KW = 1000 KW	2525 will be **0.1** KW/s