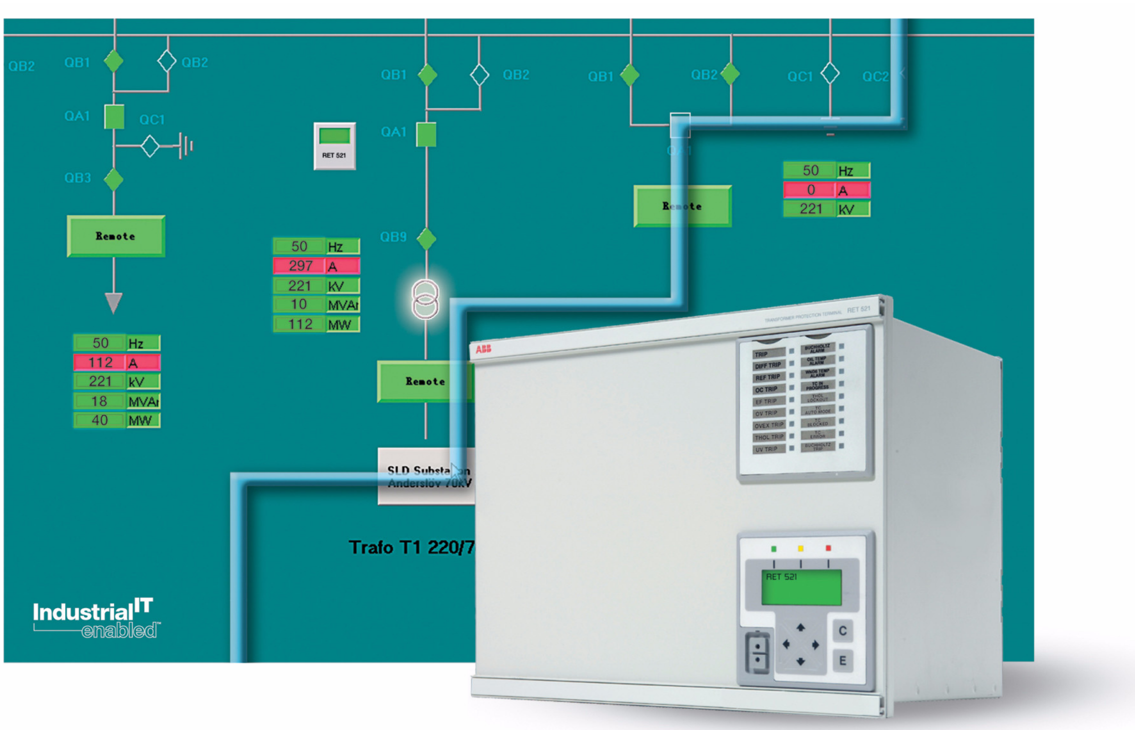
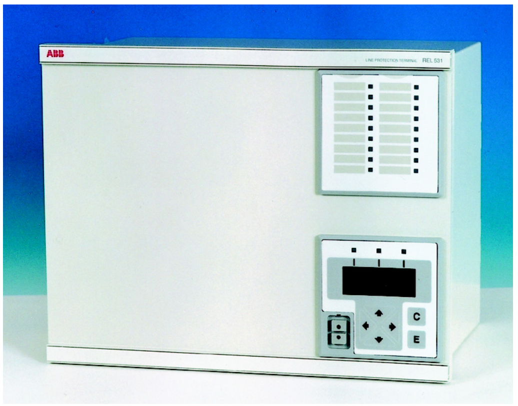
Technical reference manual

Transformer protection terminal
RET 521*2.5



Technical reference manual
Protect^{IT} Transformer protection terminal
RET 521*2.5



About this manual

DocID: 1MRK 504 036-UEN
Issue date: December 2003
Revision: -

Industrial IT

Industrial IT enabled products from ABB are the building blocks for greater productivity, featuring all the tools necessary for lifecycle product support in consistent electronic form.

Manufacturer:

ABB AutomationTechnology Products AB
Substation Automation
SE-721 59 Västerås
Sweden
Telephone: +46 (0) 21 34 20 00
Facsimile: +46 (0) 21 14 69 18
www.abb.com/substationautomation

Contents

Chapter	Page
Functional description	**7**
Design description	**303**
References	**341**
Index	**343**
Customer feedback report	**347**
Example configurations	

The chapter “Functional description”

This chapter describes the functions and logics within protection terminal RET 521. The discription deals with how the functions are designed, how they operate, and their signals and setting parameters. For hardware descriptions refer to the chapter “Design descriptions”.

RET 521 terminal functionality 17

Terminal identification 17
- General 17
- Second HMI-language 17
- Terminal identification settings 18
- Setting the terminal clock 18
- Displaying terminal identification numbers 19
- I/O module identification 19
- User configurable module identification 20

Analog input data 20
- Setting the phase reference channel 21
- Configuration for analog inputs 21
  - Setting of current channels 22
  - Setting of voltage channels 23
- Service value report 24

Power transformer rated data 24
- Basic transformer data 25
  - Vector group setting strings 25
- Two winding transformer system 27
- Three winding transformer systems 27

Activation of setting groups 29
- General 29

Internal events 29
- Using the built-in HMI 30
- Using front-connected PC or SMS 31
- Using SCS 32

Time synchronization 33
- System overview 33
- Design 34
- Configuration 34
- Setting date and time 37
- Error signals 37
  - TIME-SYNCERR 37

TIME-RTCERR ... 39
CAP terminal diagram for Time function block ... 39
CAP signal lists for Time function block ... 39
Setting table for time sources on built-in HMI ... 39

Restricted settings ... 40

General ... 40
Installation and setting instructions ... 41
Function block ... 42
Inputs and outputs ... 42
Setting parameters and ranges ... 42

Configuration overview ... 43

Description of configurations ... 46

Configuration 1 (7I + 3U) ... 46
Configuration 2 (2I + 8U) ... 46
Configuration 3 (9I + 1U) ... 47
Configuration No 4 (2x (7I + 3U)) ... 47
Configuration No 5 ([8I+2U]&[9I+1U]) ... 48
Configuration No 5a ([8I+2U]&[9I+1U]) ... 48
Configuration No 6 [9I+1U] ... 49

General functionality ... 50

Tripping logic (TR) ... 50

Summary of function ... 50
Description of logic ... 50
Logic diagram ... 51
Function block ... 51
Input and output signals ... 52
Setting parameters and ranges ... 52

Terminal hardware structure (THWS) ... 53

Summary of application ... 53
Summary of function ... 53
Description of logic ... 53
Analogue input module (AIM) ... 53
Binary input module (BIM) ... 53
Binary output module (BOM) ... 54
Input/output module (IOM) ... 54
mA input module (MIM) ... 54
Terminal hardware structure (THWS) ... 54
Function block ... 55
Analogue input module (AIM) ... 55
Binary input module (BIM) ... 57
Binary output module (BOM) ... 58

Input/output module (IOM) 59
mA input module (MIM) 60
Terminal HW structure (THWS) 61
Input and output signals 61
Setting parameters and ranges 62
Service report values 63

Activation of setting groups (GRP) 66

Summary of function 66
Function block 67
Input and output signals 67

Blocking during test (TEST) 68

Summary of function 68
Function block 68
Input and output signals 68

No signal (NONE) 69

Summary of function 69
Function block 69
Input and output signals 69

Fixed signals (FIXD) 69

Summary of function 69
Function block 70
Input and output signals 70

Fourier filter for single phase current (C1P) 71

Summary of function 71
Function block 71
Input and output signals 71

Fourier filter for three phase current (C3P) 72

Summary of function 72
Function block 72
Input and output signals 72

Sum function for three phase currents (C3C) 73

Summary of function 73
Function block 73
Input and output signals 74

Fourier filter for single phase voltage (V1P) 74

Summary of function 74
Function block 74
Input and output signals 75

Fourier filter for three phase voltage (V3P) 75

Summary of function 75
Function block 75
Input and output signals 76

Binary converter (CNV) 76

Summary of function 76
Function block 79
Input and output signals 79
Setting parameters and ranges 80

Configurable logic (CL) 80

Summary of application 80
Summary of function 80
Description of logic 80
General 80
Inverter (INV) 81
OR 81
AND 82
Timer 82
TimerLong 83
Pulse 83
Set-Reset with memory 84
MOVE 84
Function block 85
Input and output signals 88
Setting parameters and ranges 91

Command function (CM/CD) 91

Summary of application 91
Summary of function 91
Description of logic 92
General 92
Single Command function 92
Multiple Command function 92
Communication between terminals 93
Function block 93
Input and output signals 94
Setting parameters and ranges 96

Protection functions 97

Frequency measurement function (FRME) 97

Summary of application 97
Summary of function 98
Measuring principle 99
Logic diagram 105

Function block 106
Input and output signals 106
Service report values 107

Differential protection (DIFP) 107

Summary of application 107
Summary of function 108
Measuring principles 109
Some definitions and requirements 109
Power transformer connection groups 110
Determination of differential (operate) currents 111
Calculation of fundamental harmonic differential currents 112
Power transformer correction factors 115
Power transformers with On-Load Tap-Changer (OLTC) 116
T configuration (Circuit-breaker-and-a-half configuration) 117
Instantaneous differential currents 118
Differential currents due to factors other than faults 118
Elimination of zero-sequence currents from differential currents 119
Detection of inrush magnetizing currents 121
Detection of inrush 124
Detection of overexcitation magnetizing currents 126
Determination of bias current 127
Determination of bias current in breaker-and-a-half schemes 128
Restrained differential protection: operate - bias characteristics 128
Unrestrained (instantaneous) differential protection 131
Stability of differential protection against heavy external faults 131
Transformer differential protection: a summary of principles 133
Logic diagram 135
Function block 136
Input and output signals 137
Setting parameters and ranges 138
Service value report 139

Three/phase time overcurrent protection (TOC) 139

Summary of application 139
Summary of function 140
Measuring principles 140
Time characteristics 140
Calculation of IEC inverse delays 146
Directional control of overcurrent protection 147
Logic diagram 150
Function block 151
Input and output signals 152
Setting parameters and ranges 153
Service report values 154

Multipurpose General Protection Function (GF) 154

Summary of application 154

Measuring principles 156
Input quantities to GF 156
Overcurrent and overvoltage/undervoltage functions 157
Time Characteristics 157
Second harmonic blocking 161
Current restrained functionality 161
Directional characteristics 163
Voltage restrained/controlled GF-functionality 167
Logic diagram 169
Function block 170
Input and output signals 171
Setting parameters and ranges 172
Service report values 173

Restricted earth fault protection (REF) 174

Summary of application 174
Summary of function 175
Measuring principles 175
Fundamental principles of the restricted earth fault protection (REF) 175
REF as a Differential Protection 178
Calculation of Differential Current and Bias Current 179
Detection of External Earth Faults 180
Algorithm of the restricted earth fault protection (REF) in short 182
Logic diagram 183
Function block 184
Input and output signals 184
Setting parameter and ranges 184
Service report values 185

Earth fault time-current protection (TEF) 185

Application of function 185
Summary of function 186
Measuring principles 187
Non-directional earth fault protection 187
Logarithmic Curves 193
Calculation of IEC inverse delays 194
Directional control of the earth fault time current protection (TEF) 195
Logic diagram 197
Function block 198
Input and output signals 200
Setting parameters and ranges 201
Service report values 201

Single/three-phase time overvoltage protection (TOV) 202

Summary of application 202
Summary of function 203
Measuring principles 203
General on TOV protection 203

The three phase overvoltage protection 204
The residual voltage protection 205
Single input overvoltage protection 206
Logic diagrams 208
Function block 209
Input and output signals 210
Setting parameters and ranges 211
Service report values 212

Single/three-phase time undervoltage protection (TUV) 212

Summary of application 212
Summary of function 212
Measuring principles 213
General 213
Application of function inputs 213
Application of function outputs 214
Settings 215
Application of TUV protection function service value 216
Function block 216
Input and output signals 217
Setting parameters and ranges 218
Service report values 218

Thermal overload protection (THOL) 218

Summary of application 218
Summary of function 219
Measuring principles 220
General 220
Application of function outputs 220
Function service values 221
Application of function inputs 222
Application of inputs G3I and SIDE2W/SIDE3W 223
Logic diagram 224
Function block 224
Input and output signals 225
Setting parameters and ranges 225
Service report values 226

Overexcitation protection (V/Hz) (OVEX) 226

Summary of function 226
Measuring principles 227
General 227
OVEX variants 230
Operate time of the overexcitation protection. 231
Cooling 234
OVEX protection function service report 235
Logic diagram 236
Function block 237

Input and output signals 238
Setting parameters and ranges 239
Service report values 239

Frequency protection function (FRF) 240

Summary of application 240
Summary of function 240
Measuring principles 240
Input quantity 240
Basic operation 241
Time Characteristics 241
Main conditions and specifications for the frequency function FRF 242
Logic diagram 242
Function block 243
Input and output signals 243
Setting parameters and ranges 244
Service report values 244

Voltage control (VCTR) 244

Summary of function 244
Measuring principles 245
VCTR Operation Mode (i.e. Control Location) 245
Control Mode 245
Measured Quantities 246
Voltage control for parallel transformers 247
Plant with Capacitive shunt compensation 251
Manual Control of the parallel group (Adapt Mode) 252
Logic diagram 254
Function block 260
Input and output signals 263
Setting parameters and ranges 266
Service report values 270

Monitoring functionality 271

LED indication function (HL, HLED) 271

Application 271
Design 271
Function block 271
Input and output signals 272
Setting parameters 272

Event function (EV) 273

Summary of application 273
Summary of function 273
Description of logic 273
General 273

Double indication 274
Communication between terminals 274
Function block 275
Input and output signals 276
Setting parameters and ranges 277

Disturbance Report 279

Summary of application 279
Information on the built-in HMI 280
Information retrieved with SMS or SCS 280
Summary of function 281
Description of logic 282
Common functions 282
Sampling rate 285
Memory capacity 285
Indications 285
Event recorder 285
Trip values 285
Disturbance recorder 285
Function block 286
Input and output signals 290
Input signals 290
Output signals 290
Setting parameters and ranges 291
Description of parameters 291
Service value report 293

Monitoring of DC analogue measurements 294

Application 294
Function block 295
Input and output signals 295
Setting parameters 296
Technical data 298

Remote communication (RC) 298

Summary of application 298
Summary of function 299
SPA operation 300
LON operation 300
Description of logic 300
SPA communication 300
LON communication 301
Setting parameters and ranges 301
SPA communication 301
LON communication 301

RET 521 terminal functionality

1 Terminal identification

1.1 General

You can store the identification names and numbers of the station, the transformer, and the terminal itself in the terminal. This information can be read on the built-in HMI or when communicating with the terminal through a PC using SMS or SCS.

The internal clock is used for time tagging of:

- Internal events
- Disturbance reports
- Events in a disturbance report
- Events transmitted to the SCS substation control system

This implies that the internal clock is very important. The clock can be synchronized, (see the section “Time synchronization”), to achieve higher time tagging correlation accuracy between terminals. Without synchronization, the internal clock is only useful for comparisons among events within the terminal.

The ordering number, serial number, software version and identity number of I/O modules are displayed on the local HMI. For each hardware module and for the frame there is the possibility to store a user defined note.

1.2 Second HMI-language

The terminal can be ordered with one second (local) HMI-language if required. The terminal then contains both the basic english language and the second language.

The terminal will be delivered with the second language activated. Any time it is convenient it is possible to shift between the two languages in the menu (now in english).

Configuration
    Select Language

1.3 Terminal identification settings

The user configurable identification settings can be set from the HMI menu branch:

Config
Ident

The following parameters can be set

Table 1: User configurable terminal identification settings

Parameter	Setting range	Description
Unit No	(0 - 99999)	Unit No.
Unit Name	16 character string	Unit Name
Object No	(0 - 99999)	Object No.
Object Name	16 character string	Object Name
Station No	(0 - 99999)	Station No.
Station Name	16 character string	Station Name

1.4 Setting the terminal clock

The internal clock are set from the HMI menu branch:

Set
Time

Time is set by modifying the following parameters:

Table 2: Terminal date and time

Parameter	Setting range	Description
Date		Date in the format YYYY-MM-DD
Time		Time in the format HH:MM:SS

The current internal time is read from:

ServRep
Time

Note: When time synchronization is enabled, time setting is not possible.

1.5 Displaying terminal identification numbers

The terminal serial number and software version and more can be displayed from the HMI menu branch:

TermSt
  IdentNo
    Observe
      General

The following terminal information are displayed:

Table 3: Terminal identification numbers

Parameter	Description
OrderingNo	RET 521 terminal ordering number
TermSerialNo	RET 521 terminal serial number
SW-version	Software version for main program
CPU-module	CPU-module

1.6 I/O module identification

The identity of each I/O module can be displayed on the HMI by following the menu branch:

TermStat
  IdentNo
    Observe
      I/O-mod

The present I/O module is identified by its parameter. However, these parameters are configuration dependent. In the following table the mnemonic <*iomodulename*> should be replaced by whatever type of module present, e.g. AIM1, BIM1, BOM2 etc.

Table 4: I/O module identification

Parameter	Description
PCIP3-<*iomodulename*>	Identity number of module in HW SlotNo 3
PCIP7-<*iomodulename*>	Identity number of module in HW SlotNo 7
CANP9-<*iomodulename*>	Identity number of module in HW SlotNo 9
CANP10-<*iomodulename*>	Identity number of module in HW SlotNo 10
CANP11-<*iomodulename*>	Identity number of module in HW SlotNo 11
CANP12-<*iomodulename*>	Identity number of module in HW SlotNo 12

1.7 User configurable module identification

The identity of some modules can be user defined using the HMI menu branch:

TermStat
IdentNo
Noted

The following parameters can be edited to enter a custom text for description of each module.

Table 5: User configurable module identification

Parameter	Description
HMI-module	HMI-module
Frame	Mechanical frame
Power-module	Power-module
LON-module	LON-module

2 Analog input data

In order to get correct measurement results as well as correct protection functionality, the analog input channels must be configured. The channel used as a phase reference for phase angle calculations must be selected, and rated primary and secondary currents and voltages must be set.

Note: Channel identification labels (e.g. AIM1-CH03) used in this section are the default labels used when no user defined labels are set.The labels are set from CAP configuration tool by configuring the AIM1 and AIM2 function blocks.

Because all protection algorithms in RET 521 are calculated using the primary system quantities it is extremely important to properly set the data about connected current and voltage transformers. These data are calculated by the system engineer and normally set by the commissioner from the built-in HMI or from SMS.

2.1 Setting the phase reference channel

The reference channel is set from the MMI menu branch:

Config
AnalogIn

The parameter RefCh is then set to the appropriate channel (e.g. AIM1-CH07, usually the L1 phase-to-ground voltage).

2.2 Configuration for analog inputs

The terminal can be equipped with a maximum of two analog input cards, each having ten analog input channels. The cards, named AIM1 and AIM2 respectively, allows for individual setting for each channel of the following parameters:

Parameter:	Setting range:	Description:	Type:
InputCTTap	1A, 5A	Connected input CT Tap on AIM card in A	Current
CTprim	(1-99999)A	Rated CT primary current in A	Current
CTsec	(1-5)A	Rated CT secondary current in A	Current
CTstarpoint	ToObject, FromObject	Current transf. earthing, Towards object/From object	Current
VTprim	(0.1-999.9)kV	Rated VT primary voltage in kV	Voltage
VTsec	(1-999)V	Rated VT secondary voltage in V	Voltage

Note: CT parameters only present when the selected channel is a current channel, VT parameters only present when input channel is a voltage channel.

Channels are configured from the MMI menu branch:

Config
PCIP3-AIM1
AIM1-CH*nn*

for the first analog input card, or:

Config
PCIP7-AIM2
AIM2-CH*nn*

In both cases, *nn* is the channel number, ranging from 01-10.

2.2.1 Setting of current channels

The parameter InputCTTap is used to determine to which tap, on RET 521 input terminals, the wire from the main CT is connected. For more info about that see figure 1. It should be noted that this parameter can be only set from the built-in HMI.

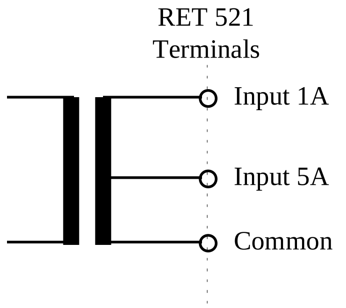


Fig. 1 CT Connections to RET 521

Parameter *"CTstarpoint"* determines in which direction current is measured. Internal reference direction is that all currents are always measured towards the protected object (i.e. towards the power transformer).

An example for setup of all CT parameters is shown in figure 2.

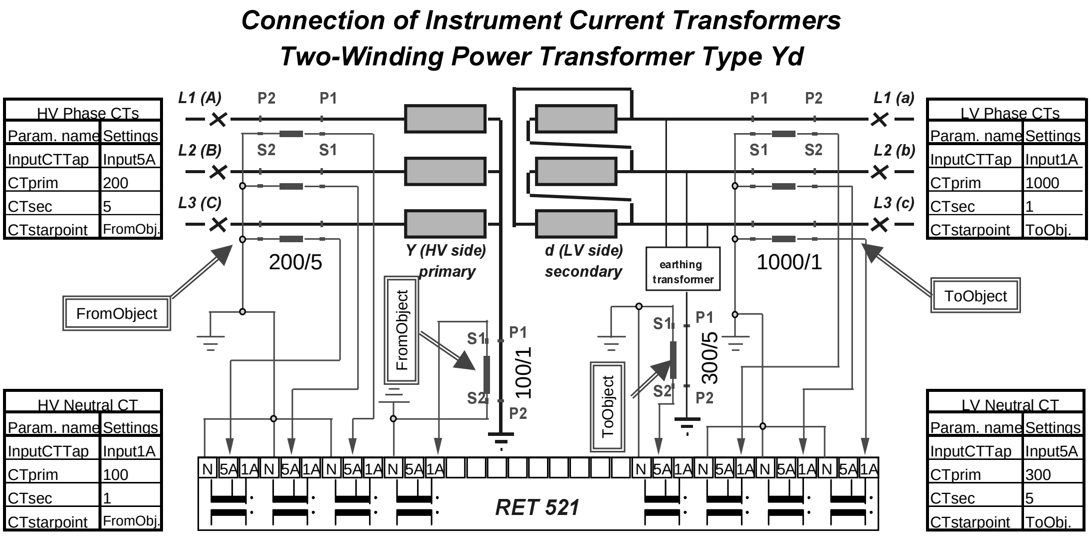


Fig. 2 CT Setup Example

When the configuration parameters of the CTs are made according to these instructions, functions depending on the direction of the current, will automatically be set up correctly. That means that the differential protection now is set up correctly.

Other directional protections as directional overcurrent protection or directional earth fault protection also need to know on which side of the power transformer they are configured. That information is given in the configuration parameter “Side2w” or “Side3w”. Now the directionality is set up so that the setting “*forward*” means the direction out from the transformer into the surrounding network and vice versa for the ”*reverse*” setting. The same directions apply as well when configuration parameter “Side2w” or “Side3w” is set to “UserDefined”.

2.2.2 Setting of voltage channels

It should be noted that in case of phase to earth voltage measurement with the following VT data,

$$\frac{132\text{ kV}/\sqrt{3}}{110\text{ V}/\sqrt{3}}$$

the following settings should be used:

VTprim = 132kV

VTsec = 110V.

2.3 Service value report

Table 6: Service values for AIM measuring current

Parameter:	Range:	Step:	Description:
AngleCIn	0.0 - 359.9	0.1	Current angle, input n (n=01-09), in degrees
MagCIn	0 - 99999	1	Current magnitude, input n, in A

Table 7: Service values for AIM measuring voltage

Parameter:	Range:	Step:	Description:
AngleVIn	0.0 - 359.9	0.1	Voltage angle, input n (n=07-10), in degrees
MagVIn	0 - 1999.9	0.1	Voltage magnitude, input n, in kV

3 Power transformer rated data

Because all protection algorithms in RET 521 do all calculations in primary system quantities, and all settings are related to the rated quantities of the protected power transformer it is extremely important to properly set the data about protected transformer. Required data can be easily found on transformer name plate. These data are normally set by the commissioner using the built-in HMI or SMS/SCS.

Please note that all data need to be set. Rated voltage values, as an example, are required even when there is no over-/undervoltage functions installed, because the transformer differential protection function uses these values to calculate the turns ratio of the power transformer.

Note: The power transformer data is part of the functions found under setting groups 1-4, functions that are managed in four separately configurable groups for extended flexibility. Depending on which group is used for setting, *n* ranges from 1-4. If the protection scheme requires more than one setting group, transformer data must be copied to or set for each used setting group.

3.1 Basic transformer data

When using the built-in HMI, basic transformer data can be set using the menu branch:

Settings
  Functions
    Group *n*
      TransfData
        Basic Data

Table 8: Basic transformer data, two winding transformer

Parameter description	Parameter name	Range	Default
Transformer Vector Group	VectorGroup 2W	See Fig. 3	Yy00
Rated Transformer Power in MVA	Sr	0.1-9999.9	173.2

In a three winding transformer system, the rated power is set for each winding, thus excluded from the basic data.

Table 9: Basic transformer data, three winding transformer

Parameter description	Parameter name	Range	Default
Transformer Vector Group	VectorGroup 3W	See Fig. 4	Yy00y00

3.1.1 Vector group setting strings

When setting the vector group, a number between 1 and 24 (two winding transformer) or between 1 and 288 (three winding transformer) is entered, corresponding to a certain vector group. When viewing the set vector group a three or four character string, constructed by combining the primary winding coupling (Y or D) with a vector code for the secondary winding, is displayed instead of the number.The following illustrations displays the correspondence between entered number and vector groups.

W1=Y (Primary Winding)	W2 (Secondary Winding)											
	y00	y02	y04	y06	y08	y10	d01	d03	d05	d07	d09	d11
	1	2	3	4	5	6	7	8	9	10	11	12

Settings for Vector Group No for Two Winding Power Transformers with Star Connected Primary Winding

W1=D (Primary Winding)	W2 (Secondary Winding)											
	y01	y03	y05	y07	y09	y11	d00	d02	d04	d06	d08	d10
	13	14	15	16	17	18	19	20	21	22	23	24

Settings for Vector Group No for Two Winding Power Transformers with Delta Connected Primary Winding

99000001.ppt

Fig. 3 Vector group reference table for two winding systems

W1=Y		W3 (Tertiary Winding)											
(Primary Winding)		y00	y02	y04	y06	y08	y10	d01	d03	d05	d07	d09	d11
	y00	1	2	3	4	5	6	7	8	9	10	11	12
W2	y02	13	14	15	16	17	18	19	20	21	22	23	24
	y04	25	26	27	28	29	30	31	32	33	34	35	36
Sec	y06	37	38	39	40	41	42	43	44	45	46	47	48
	y08	49	50	51	52	53	54	55	56	57	58	59	60
W	y10	61	62	63	64	65	66	67	68	69	70	71	72
i	d01	73	74	75	76	77	78	79	80	81	82	83	84
n	d03	85	86	87	88	89	90	91	92	93	94	95	96
d	d05	97	98	99	100	101	102	103	104	105	106	107	108
i	d07	109	110	111	112	113	114	115	116	117	118	119	120
n	d09	121	122	123	124	125	126	127	128	129	130	131	132
g	d11	133	134	135	136	137	138	139	140	141	142	143	144

Settings for Vector Group No for Three Winding Power Transformers with Star Connected Primary Winding

W1=D		W3 (Tertiary Winding)											
(Primary Winding)		y01	y03	y05	y07	y09	y11	d00	d02	d04	d06	d08	d10
	y01	145	146	147	148	149	150	151	152	153	154	155	156
W2	y03	157	158	159	160	161	162	163	164	165	166	167	168
	y05	169	170	171	172	173	174	175	176	177	178	179	180
Sec	y07	181	182	183	184	185	186	187	188	189	190	191	192
	y09	193	194	195	196	197	198	199	200	201	202	203	204
W	y11	205	206	207	208	209	210	211	212	213	214	215	216
i	d00	217	218	219	220	221	222	223	224	225	226	227	228
n	d02	229	230	231	232	233	234	235	236	237	238	239	240
d	d04	241	242	243	244	245	246	247	248	249	250	251	252
i	d06	253	254	255	256	257	258	259	260	261	262	263	264
n	d08	265	266	267	268	269	270	271	272	273	274	275	276
g	d10	277	278	279	280	281	282	283	284	285	286	287	288

Settings for Vector Group No for Three Winding Power Transformers with Delta Connected Primary Winding

99000003.ppt

Fig. 4 Vector group reference table for three winding systems

3.2 Two winding transformer system

Primary winding data is set using the menu branch:

Settings
  Functions
    Group *n*
      TransfData
        Winding 1

Table 10: Primary winding transformer data

Parameter description	Parameter name	Range	Default
Rated Current for Primary Winding in A	Ir1	1-99999	1000
Rated Phase to Phase Voltage for Primary Winding in kV	Ur1	0.1-999.9	100.0

Secondary winding data is set using the menu branch:

Settings
  Functions
    Group *n*
      TransfData
        Winding 2

Table 11: Secondary winding data

Parameter description	Parameter name	Range	Default
Rated Current for Secondary Winding in A	Ir2	1-99999	1000
Rated Phase to Phase Voltage for Secondary Winding in kV	Ur2	0.1-999.9	100.0

3.3 Three winding transformer systems

When the terminal is intended for protection of a three winding transformer, the parameters are somewhat different. Primary winding data is set using the HMI menu branch:

Settings
  Functions
    Group *n*
      TransfData
        Winding 1

Table 12: Three winding transformer data, primary winding

Parameter Description	Parameter Name	Range	Default
Rated Power of Primary Winding in MVA	Sr1	0.1-9999.9	173.2
Rated Current for Primary Winding in A	Ir1	1-99999	1000
Rated Phase to Phase Voltage for Primary Winding in kV	Ur1	0.1-999.9	100.0

Secondary winding data is set using the HMI menu branch:

Settings
  Functions
    Group *n*
      TransfData
        Winding 2

Table 13: Three winding transformer data, secondary winding

Parameter Description	Parameter Name	Range	Default
Rated Power of Secondary Winding in MVA	Sr2	0.1-9999.9	173.2
Rated Current for Secondary Winding in A	Ir2	1-99999	1000
Rated Phase to Phase Voltage for Primary Winding in kV	Ur2	0.1-999.9	100.0

Tertiary winding data is set using the HMI branch:

Settings
  Functions
    Group *n*
      TransfData
        Winding 3

Table 14: Three winding transformer data, tertiary winding

Parameter Description	Parameter Name	Range	Default
Rated Power of Tertiary Winding in MVA	Sr3	0.1-9999.9	173.2
Rated Current for Tertiary Winding in A	Ir3	1-99999	1000
Rated Phase to Phase Voltage for Primary Winding in kV	Ur3	0.1-999.9	100.0

4 Activation of setting groups

4.1 General

Different conditions in networks of different voltage levels require high adaptability of the used protection and control units to best provide for dependability, security and selectivity requirements. Protection units operate with higher degree of availability, especially, if the setting values of their parameters are continuously optimized regarding the conditions in power system.

Therefore, the terminal has been equipped with four independent groups (sets) of setting parameters. These groups can be activated at any time in different ways:

- Locally, by means of the local human-machine interface (HMI).
- Locally, by means of a PC, using the Parameter Setting Tool (PST) in CAP 540 or using the Station Monitoring System (SMS).
- Remotely, by means of the Parameter Setting Tool (PST) in the Station Control System (SCS).
- Remotely, by means of the Station Monitoring System (SMS).
- Locally, by means of up to four programmable binary inputs.

5 Internal events

Internal events are generated by the built-in supervisory functions. The supervisory functions supervise the status of the various modules in the terminal and, in case of failure, a corresponding event is generated. Similarly, when the failure is corrected, a corresponding event is generated.

Apart from the built-in supervision of the various modules, events are also generated when these functions change status:

- Built-in real time clock (in operation/out of order)
- External time synchronization (in operation/out of order)

Events are also generated on these occasions:

- Whenever any setting in the terminal is changed
- When the content of the disturbance report is erased

Internal events can be presented at three different locations:

- At the terminal using the built-in HMI
- Remotely using front-connected PC or SMS
- Remotely using SCS

5.1 Using the built-in HMI

If an internal fault has occurred, the built-in HMI displays information under:

Terminal Status
Self Superv

Here, there are indications of internal failure (serious fault), or internal warning (minor problem).

There are also indications regarding the faulty unit, according to Table 15.

Table 15: Self-supervision signals in the built-in HMI

HMI information:	Status:	Signal name:	Activates summary signal:	Description:
InternFail	OK / FAIL	INT--FAIL		Internal fail summary. Signal activation will reset the terminal
Intern Warning	OK /WARNING	INT--WARNING		Internal warning summary
NUM-modFail	OK / FAIL	INT--NUMFAIL	INT--FAIL	Numerical module failed. Signal activation will reset the terminal
NUM-modWarning	OK /WARNING	INT--NUMWARN	INT--WARNING	Numerical module warning (failure of clock, time synch.
PCIPx-AIMn	OK / FAIL	AIMn-Error	INT--FAIL	Analogue input module n failed. Signal activation will reset the terminal
CANPx-YYYn	OK / FAIL	IOn--Error	INT--FAIL	I/O module (YYY = BIM, BOM, IOM) n failed. Signal activation will reset the terminal
CANPx-MIM1	OK / FAIL	MIM1-Error	INT--FAIL	mA input module MIM1 failed. Signal activation will reset the terminal
Real Time Clock	OK /WARNING	INT--RTC	INT--WARNING	Internal clock is reset - Set the clock

Table 15: Self-supervision signals in the built-in HMI

HMI information:	Status:	Signal name:	Activates summary signal:	Description:
Time Sync	OK /WARNING	INT--TSYNC	INT--WARNING	No time synchronization

You can also connect the internal signals, such as INT--FAIL and INT--WARN to binary output contacts for signalling to a control room.

In the Terminal Status information, you can view the present information from the self-supervision function. Indications of failure or warnings for each hardware module are provided, as well as information about the external time synchronization and the internal clock, according to Table 15. Recommendations are given on measures to be taken to correct the fault. Loss of time synchronization can be considered as a warning only. The terminal has full functionality without time synchronization.

5.2 Using front-connected PC or SMS

Here two summary signals appear, self-supervision summary and numerical module status summary. These signals can be compared to the internal signals as:

- Self-supervision summary = INT--FAIL and INT--WARNING
- CPU-module status summary = INT--NUMFAIL and INT--NUMWARN

When an internal fault has occurred, you can retrieve extensive information about the fault from the list of internal events available in the SMS part:

TRM-STAT TermStatus - Internal Events

The list of internal events provides valuable information, which can be used during commissioning and during fault tracing.

The internal events are time tagged with a resolution of 1 ms and stored in a list. The list can store up to 40 events. The list is based on the FIFO principle, when it is full, the oldest event is overwritten. The list cannot be cleared; its content cannot be erased.

The internal events in this list not only refer to faults in the terminal, but also to other activities, such as change of settings, clearing of disturbance reports, and loss of external time synchronization.

The information can only be retrieved with the aid of the PST software package. The PC can be connected either to the port at the front or at the rear of the terminal.

These events are logged as internal events.

Table 16: Events available for the internal event list in the terminal

Event message:		Description:	Generating signal:
INT--FAIL	Off	Internal fail status	INT--FAIL (reset event)
INT--FAIL	■On		INT--FAIL (set event)
INT--WARNING	Off	Internal warning status	INT--WARNING (reset event)
INT--WARNING	■On		INT--WARNING (set event)
INT--NUMFAIL	Off	Numerical module fatal error status	INT--NUMFAIL (reset event)
INT--NUMFAIL	■On		INT--NUMFAIL (set event)
INT--NUMWARN	Off	Numerical module non-fatal error status	INT--NUMWARN (reset event)
INT--NUMWARN	■On		INT--NUMWARN (set event)
IOn--Error	Off	In/Out module No. n status	IOn--Error (reset event)
IOn--Error	■On		IOn--Error (set event)
AIMn-Error	Off	Analogue input module No. n status	AIMn-Error (reset event)
AIMn-Error	■On		AIMn-Error (set event)
MIM1-Error	Off	mA-input module status	MIM1-Error (reset event)
MIM1-Error	■On		MIM1-Error (set event)
INT--RTC	Off	Real Time Clock (RTC) status	INT--RTC (reset event)
INT--RTC	■On		INT--RTC (set event)
INT--TSYNC	Off	External time synchronization status	INT--TSYNC (reset event)
INT--TSYNC	■On		INT--TSYNC (set event)
INT--SETCHGD		Any settings in terminal changed	
DRPC-CLEARED		All disturbances in Disturbance report cleared	

5.3 Using SCS

Internal events can also be sent to the Station HMI in a Substation Control System (SCS). Some signals are available from a function block InternSignals (INT). The signals from this function block are connected to an Event function block, which generates and sends these signals as events to the station level of the SCS. The signals from the INT-function block can also be connected to binary outputs for signalization via output relays or they can be used as conditions for certain functions. These connections are performed from the CAP Configuration tool.

Individual error signals from I/O modules and time synchronization can be obtained from respective function block of IOM-, BIM-, BOM-, MIM- and AIM-modules and from the time synchronization block TIME.

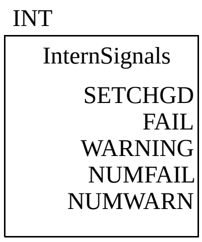


Fig. 5 Simplified terminal diagram of the Internal Signals function

The output signals from the function block INT:

Table 17: Output signals for INT

Out:	Description:
INT--SETCHGD	Setting changed
INT--FAIL	Internal fail status
INT--WARNING	Internal warning status
INT--NUMFAIL	NUM module fail status
INT--NUMWARN	NUM module warning status

6 Time synchronization

6.1 System overview

The terminal has a built-in real time clock (RTC) with a resolution of one millisecond. The terminal is also provided with a calendar. The starting date and time is 1970-01-01 00:00:00. The last date and time is 2037-12-31 23:59:59. The clock and calendar is battery- backed to provide safe operation also during supply failure.

The terminal can be synchronized via the serial ports and via a binary input.

On the serial buses (both LON and SPA) two types of synchronization messages are sent.

- Coarse message is sent every minute and comprises complete date and time, i.e. year, month, day, hours, minutes, seconds and milliseconds
- Fine message is sent every second and comprises only seconds and milliseconds.

Synchronization via a binary input is intended for minute pulses from e.g. a station master clock. Both positive and negative edge on the signal can be accepted.This signal is also considered as a fine signal.

6.2 Design

The time synchronization algorithm sets the internal time to a minimal error by adjusting the clock rate in small steps using one or two external synchronization sources. This way the clock will maintain a long-time rate accuracy better than 2 ppm.

The clock error is the difference between the actual time of the clock, and the time the clock is intended to have. The clock accuracy shows how much the error increases, that is, how much the clock gains or loses time.

The design allows for sporadic loss of synchronization sources and bad time messages. Normally it takes up to 20 minutes after power on to reach full accuracy, for instance when using course LON synchronization and fine minute-pulse, ±1 ms clock error.

6.3 Configuration

The following configuration alternatives for time synchronization are available in the RET 521 terminal:

FineTimeSrc:

- None
- LON
- SPA
- BinIn_Pos
- BinIn_Neg

CoarseTimeSrc:

- None
- LON
- SPA

Table 18: Time source configuration alternatives

	FineTimeSrc	Coarse-TimeSrc	Description
1.	None	None	No external time sync, time is set from terminal HMI.
2.	LON	LON	Time synchronization from LON. Coarse time from LON.
3.	LON	SPA	Time synchronization from LON. Coarse time from SPA.
4.	SPA	SPA	Time synchronization from SPA. Coarse time from SPA.
5.	SPA	LON	Time synchronization from SPA. Coarse time from LON.
6.	BinIn_Pos	None	Time synchronization from Binary Minute pulse, positive edge. No coarse time.
7.	BinIn_Neg	None	Time synchronization from Binary Minute pulse, negative edge. No coarse time.
8.	BinIn_Pos	LON	Time synchronization from Binary Minute pulse, positive edge. Coarse time from LON.
9.	BinIn_Neg	LON	Time synchronization from Binary Minute pulse, negative edge. Coarse time from LON.
10.	BinIn_Pos	SPA	Time synchronization from Binary Minute pulse, positive edge. Coarse time from SPA.
11.	BinIn_Neg	SPA	Time synchronization from Binary Minute pulse, negative edge. Coarse time from SPA.
12.	SPA	None	Time synchronization from SPA. No coarse time.
13.	LON	None	Time synchronization from LON. No coarse time.
14.	None	SPA	No time synchronization. Coarse time from SPA
15.	None	LON	No time synchronization. Coarse time from LON.

If no external time is available (alt.1), the system time will be taken from the battery-backed RTC at start-up. After that the terminal time can be set from the built in HMI.

If no coarse time is available (alt. 6,7,12,13) and fine time exists, the RTC time is used as terminal time at start-up. Then the fine time is used for synchronization.

If no fine time is available (alt. 14,15) and coarse time exists, the coarse time is used for synchronization of the system time as long as it does not deviate more than 0,5 seconds from the terminal time. If the deviation is larger than 0,5 seconds the terminal time will be set to the value of the coarse time message.

If both fine and coarse time exists (alt. 2-5, 8-11), the first coarse time message will set the terminal time. After that the fine time is used for synchronization. If coarse time deviates more than 10 seconds from the terminal time, the terminal time will be set to the value of the coarse time message.

In order to achieve ±1ms relative time synchronization accuracy between the terminals it is recommended to use alternative 8 or 9 from the previous table.

Configuration of time sources can be done from the built-in HMI at:

Configuration
Time
FineTimeSrc
CoarseTimeSrc

...and from the graphical configuration tool CAP tool:

In the function block **TIME** the following inputs are used:

- M**INSYNC** Minute pulse synchronization input. Should be connected to a binary input if SYNSOURC is set to BinIn_XXX.
- **SYNSOURC** Fine time source
- **COARSE** Coarse time source

When configuring the time synchronization with CAP the user has to verify that the terminal restarts. Until a restart occurs the new configuration of the time sync will not be enabled.

A restart can be triggered by changing HW configuration together with the above configuration or by changing a configuration parameter (see Configuration menu) in the HMI.

When changing the Time sync configuration via the HMI a restart will always occur and thus enabling the new configuration.

A binary input signal used for Minute pulse (HMI: Time/Source/TIME-MINSYNC alt. CAP: TIME/MINSYNC) is dedicated for that purpose and must not be connected to anything else.

6.4 Setting date and time

If no external time is available (alternative 1 in table 1) the internal time can be set on the built-in HMI display at:

Settings
Time

If CoarseTimeSrc is set to SPA (alternative 3, 4, 10, 11, 14 in table 1) the internal time can be set via SMS (Station Monitoring System) at:

Settings
Terminal Time

The time is set with year, date and time.

The maximum time that can be set is 2037-Dec-31 23:59:59. When the internal clock has overflowed, this will be handled so that the protection functions of the terminal will not be disturbed.

The minimum time that can be set is 1970-Jan-01 00:00:00.

6.5 Error signals

Two error signals are available for time errors:

- TIME-RTCERR internal RTC errors
- TIME-SYNCERR time synchronization error

TIME-SYNCERR will be set to *WARNING* during terminal startup, and will be set to *OK* when the calculated error of the clock is less than 10 ms.

Both signals are normally in state *OK* and will change to *WARNING* when an error occurs.

6.5.1 TIME-SYNCERR

If no external time synchronization is available, i.e. both FineTimeSrc and CoarseTimeSrc is set to *none*, TIME-SYNCERR is always *OK*.

If external time synchronization is available, TIME-SYNCERR will change from WARNING to OK at start or restart of each configured source. This means that time synchronization is up and running. It should however be noted, that TIME-SYNCERR = OK does <u>not</u> indicate that the system time has been synchronized to the required accuracy.

The status of these error signals is shown on the HMI at:

Terminal Status
Self Superv
Time Sync
Real Time Clock

The error signals can also be found in the **TIME** function block in the CAP tool, refer to Appendix. Both error signals are reported to the RET 521 internal event list which can be uploaded to the SMS PC software for evaluation.

6.5.1.1 Causes for error signals

TIME-SYNCERR:

- Malfunctioning or missing binary IO module.
- Malfunctioning AIM, TIM or CIM module.
- The calculated error of the internal time is larger than 10 ms.
- Error in synchronization signals according to the following section.

6.5.1.2 Check of synchronization signals

Binary minute pulses are checked with reference to frequency. Period time (a) should be 60 seconds. Deviations larger than ±50 ms will cause TIME-SYNCERR.

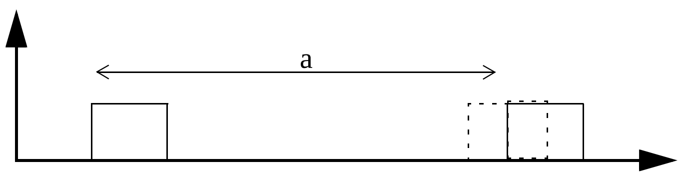


Fig. 6 Binary minute pulses

Loss of minute pulse signals will cause an internal timer to generate TIME_SYNCERR after 2 minutes.

SPA and LON time are checked according to the following:

1. Time messages from SPA and LON should have a period time of 1 second for fine synchronization messages. Loss of SPA or LON synchronization signals will cause an internal timer to generate TIME_SYNCERR after 2 minutes.
2. In a synchronized node, a discrepancy between message time and terminal time of more than 10 seconds will cause TIME_SYNCERR.

6.5.2 TIME-RTCERR

Activation of this signal can have two causes:

1 Failure in reading the RTC time at start-up.

2 Overflow of the internal clock. This will happen in the year 2038.

6.6 CAP terminal diagram for Time function block

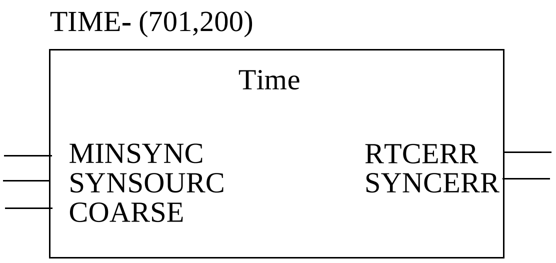


Fig. 7 Function block

6.7 CAP signal lists for Time function block

Input signals:	**Description:**
TIME-MINSYNC	Minute pulse synchronization input
TIME-SYNSOURC	fine time source input. Setting range: refer to table 3.3
TIME-COARSE	Coarse time source input. Setting range: refer to table 3.3

Output signals:	**Description:**
TIME-SYNCERR	Synchronization error
TIME-RTCERR	Internal clock error

6.8 Setting table for time sources on built-in HMI

Parameter:	**Setting range:**
FineTimeSrc	None, LON, SPA, BinIn Pos, BinIn Neg
CoarseTimeSrc	None, LON, SPA

7 Restricted settings

Do not set this function in operation before carefully reading these instructions and configuring the HMI--BLOCKSET functional input to the selected binary input.

The HMI--BLOCKSET functional input is configurable only to one of the available binary inputs. For this reason, the terminal is delivered with the default configuration, where the HMI--BLOCKSET signal is connected to NONE-NOSIGNAL.

7.1 General

Setting values of different control and protection parameters and the configuration of different function and logic circuits within the terminal are important not only for reliable and secure operation of the terminal, but also for the entire power system.

Non-permitted and non-coordinated changes, done by unauthorized personnel, can cause severe damages in primary and secondary power circuits. They can influence the security of people working in close vicinity of the primary and secondary apparatuses and those using electric energy in everyday life.

For this reason, the terminal include a special feature that, when activated, blocks the possibility to change the settings and/or configuration of the terminal from the HMI module.

All other functions of the local human-machine communication remain intact. This means that an operator can read all disturbance reports and other information and setting values for different protection parameters and the configuration of different logic circuits.

This function permits remote resetting and reconfiguration through the serial communication ports, when the setting restrictions permit remote changes of settings. The setting restrictions can be set only on the local HMI.

7.2 Installation and setting instructions

Fig. 8 presents the combined connection and logic diagram for the function.

Configuration of the HMI--BLOCKSET functional input signal under the submenu is possible only to one of the built-in binary inputs:

Configuration
  BuiltInHMI

Carefully select a binary input not used by or reserved for any other functions or logic circuits, before activating the function.

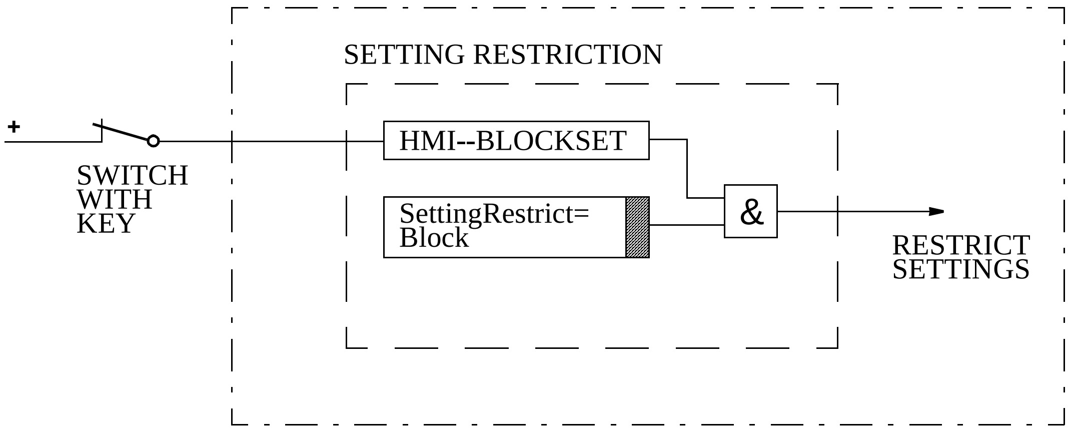


Fig. 8 Connection and logic diagram for the BLOCKSET function.

Set the setting restriction under the submenu:

Configuration
  BuiltInHMI
    SettingRestrict

to SettingRestrict = Block.

The selected binary input must be connected to the control DC voltage via a normally closed contact of a control switch, which can be locked by a key. Only when the normally closed contact is open, the setting and configuration of the terminal via the HMI is possible.

7.3 Function block

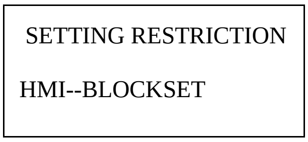


Fig. 9

7.4 Inputs and outputs

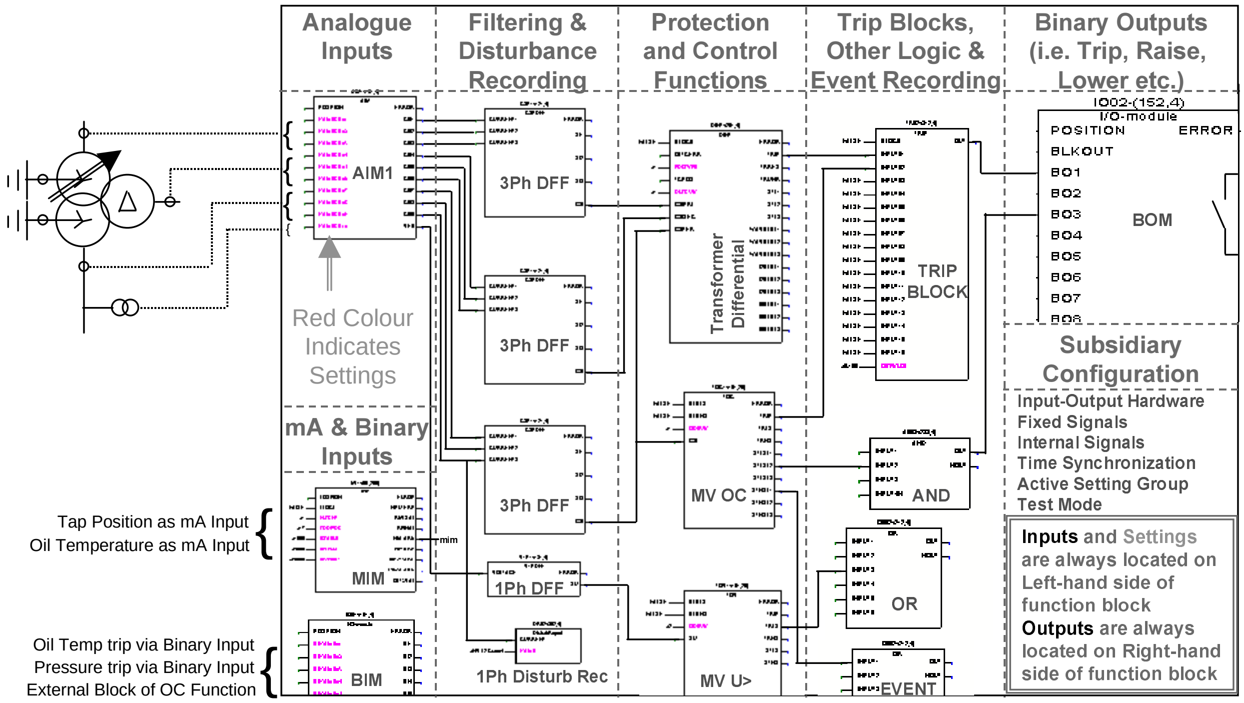
In:	**Description:**
BLOCKSET	Input signal to restrict the setting and configuration options by the HMI unit. **Warning:** Read the instructions before use. Default configuration to NONE-NOSIGNAL.

7.5 Setting parameters and ranges

Table 19:

Parameter:	**Range:**	**Description:**
SettingRestrict	Open, Block	*Open:* Permits changes of settings and configuration by means of the HMI unit regardless of the status of input HMI--BLOCKSET. *Block:* Inhibits changes of settings and configuration via the HMI unit when the HMI--BLOCKSET input signal is equal to logic one.

8 Configuration overview



As it can be seen from the above figure the complete RET 521 configuration can be subdivided in the following seven parts:

Analogue Inputs

Here the configuration of AIM modules (i.e. CT and VT inputs) is performed. First of all allocation of CT & VT inputs are done in the CAP tool. Here especial care shall be taken by the user to check that the CT & VT input allocations in CAP tool and external wiring to the RET 521 terminal corresponds to each other. Please note that the CAP tool itself is not capable to check this! In the same time the names for all CT & VT inputs are given. These names are strings, 13 characters long and therefore they can be written in any language. These names are very important for the future operators of the RET terminal because they will be visible in the built-in HMI and in the setting tool.

Filtering and Disturbance Recording

Outputs from the AIM modules are then connected to the current & voltage filters as well as to individual disturbance recording channels. Please note that in almost all applications only the positive outputs (for example CI01+) from the AIM modules shall be used. The negative outputs (for example CI01-) from the AIM modules are used only for very special applications (i.e. Scott Transformer Protection, Phase Shifting Transformer Protection etc.). The three-phase current and voltage filters provide in the same time grouping of the three-phase quantities into one signal (i.e. output G3I on C3P1 block) which are then used by most of the protection and control functions. The individual names for all ten disturbance recording channels are given here as well. These names are strings, 13 characters long and therefore they can be written in any language. These names are very important because they will be used by disturbance evaluation tool (i.e. REVAL) to identify the analogue signals. The common practice is to give the same name as for the corresponding CT or VT input.

mA & Binary Inputs

Here the configuration of MIM & BIM modules (i.e. mA and binary inputs) is performed. First of all allocation of mA and binary inputs are done in the CAP tool. Here especial care shall be taken by the user to check that the mA and binary inputs allocations in CAP tool and external wiring to the RET 521 terminal corresponds to each other. Please note that the CAP tool itself is not capable to check this! In the same time the names for all binary inputs are given. These names are strings, 13 characters long and therefore they can be written in any language. These names are very important for the future operators of the RET terminal because they will be visible in the built-in HMI and in the setting tool. For example the mA signals can be used to provide the tap position indication or oil/winding temperature measurement if suitable transducers are available. The binary inputs are usually used to cause external tripping & alarming (i.e. transformer guards), blocking or enabling of certain functions in RET 521, breaker position indication, minute pulse for time synchronization etc.

Protection and Control Functions

Here the configuration of protection and control functions is performed. First of all outputs from current & voltage filters are connected to corresponding inputs of the protection and control functions. By doing this, the connections between main CTs and/or VTs and RET 521 protection and control functions are finally made. Here special care shall be taken by the user to make sure that proper current and/or voltage signals are connected to appropriate functions (i.e. HV three-phase current signal is connected to HV overcurrent protection function). Please note that the CAP tool itself is not capable to check this! When this is done for all functions the function binary input signals (i.e. block input) shall be connected. Finally the CAP tool variables shall be defined for all function outputs which will be used in some other parts of the configurations (i.e. trip outputs at least).

Trip Blocks, Other Logic, Disturbance Report & Event Recording

Here the configuration of the binary signals is performed. First of all trip signals, either external (i.e. transformer guard trips) or internal (i.e. differential function trip) are connected to the corresponding trip logic blocks. In this way grouping and sealing of all trips for the specific circuit breaker is provided.

In addition to this the client specific logic can be made by using internally available AND gates, OR gates, flip-flops, timers etc. Up to 48 binary signals can be as well connected to the disturbance report function blocks in order to provide the binary signal recording during the power system disturbances. Finally the selected binary signals can be connected to event function blocks in order to automatically report the change of the signal status to the substation control system via LON bus.

Binary Outputs

Here the configuration of BOM modules (i.e. binary contact outputs from the RET 521 terminal) is performed. First of all, allocation of all binary outputs are done in the CAP tool. Here especial care shall be taken by the user to check that the binary outputs allocations in CAP tool and external wiring to the RET 521 terminal corresponds to each other. Please note that the CAP tool itself is not capable to check this! In the same time the names for all binary outputs are given. These names are strings, 13 characters long and therefore they can be written in any language. These names are very important for the future operators of the RET terminal because they will be visible in the built-in HMI and in the setting tool. The binary outputs are used to give the trip commands to the corresponding circuit breakers, lower and raise commands to the tap changer, remote alarming and signalling etc.

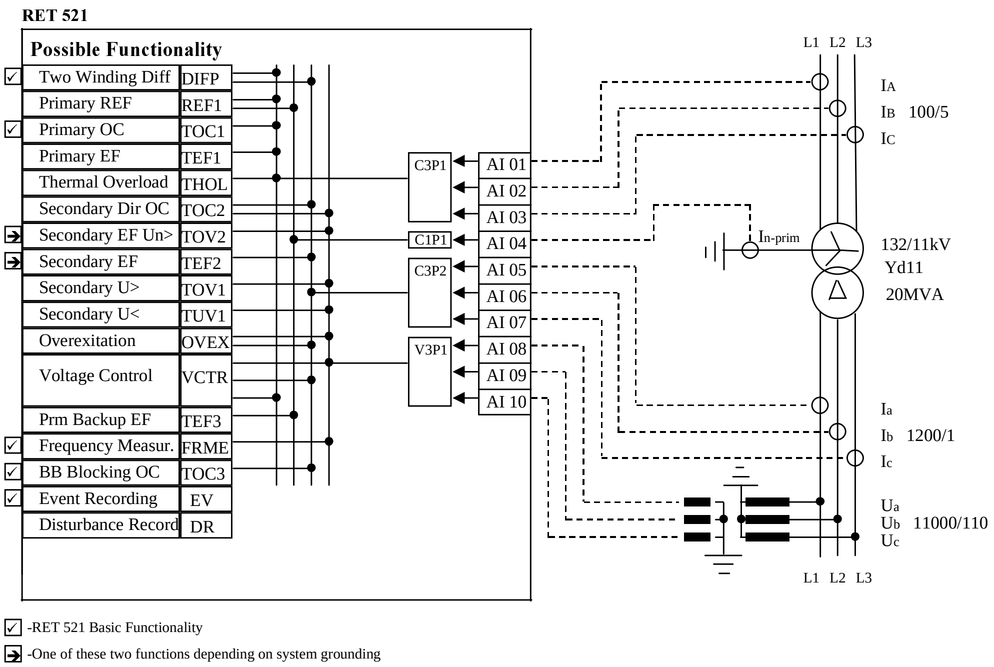
Subsidiary Configuration

This part of configuration has nothing to do directly with the protection and control functionality of the RET 521 terminal. However it is **extremely important** to configure it properly, otherwise the complete configuration will not work. First of all the terminal hardware structure (function block THWS in CAP tool) must be defined. This is done by connecting the outputs from this function block to the corresponding inputs of the hardware related function blocks (i.e. AIM, BIM, BOM, IOM & MIM function blocks). Then by using the function block for fixed signals (function block FIXD in CAP tool) the logical zero (i.e. false) and logical one (i.e. true) are defined. After this the additional configuration for time synchronization, terminal internal self-supervision, active setting group, test mode etc. is performed as per the client requirements.

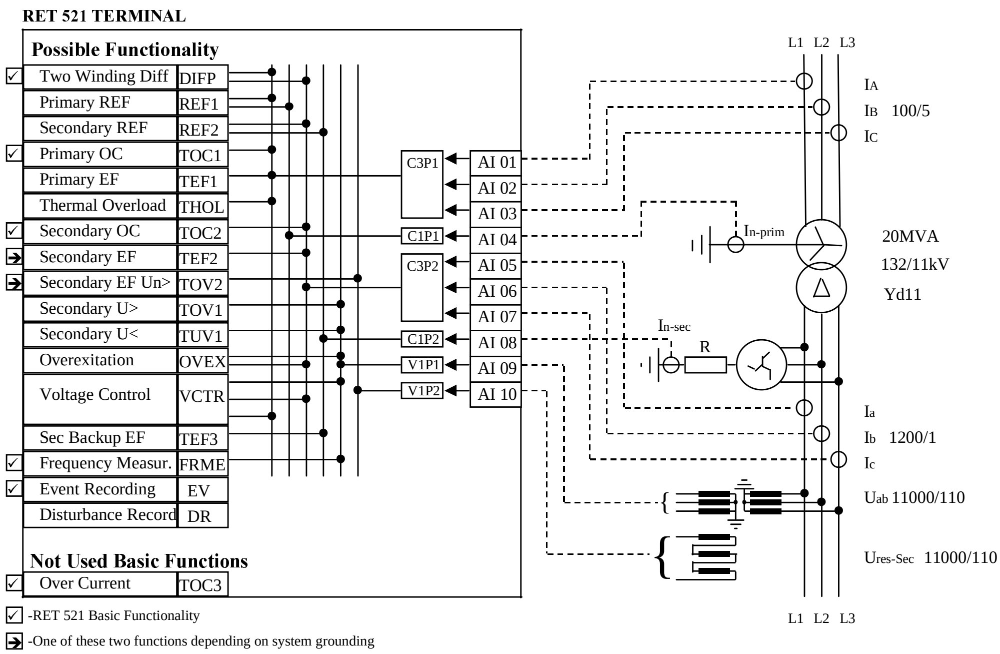
Only when all these parts are finished the complete configuration can be compiled and downloaded into the RET 521 terminal.

9 Description of configurations

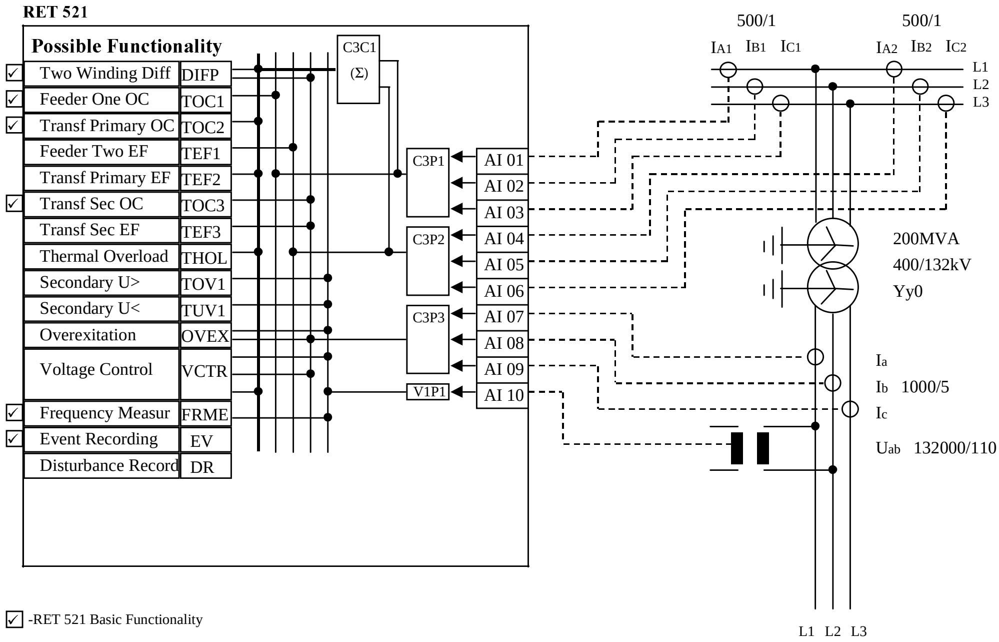
9.1 Configuration 1 (7I + 3U)



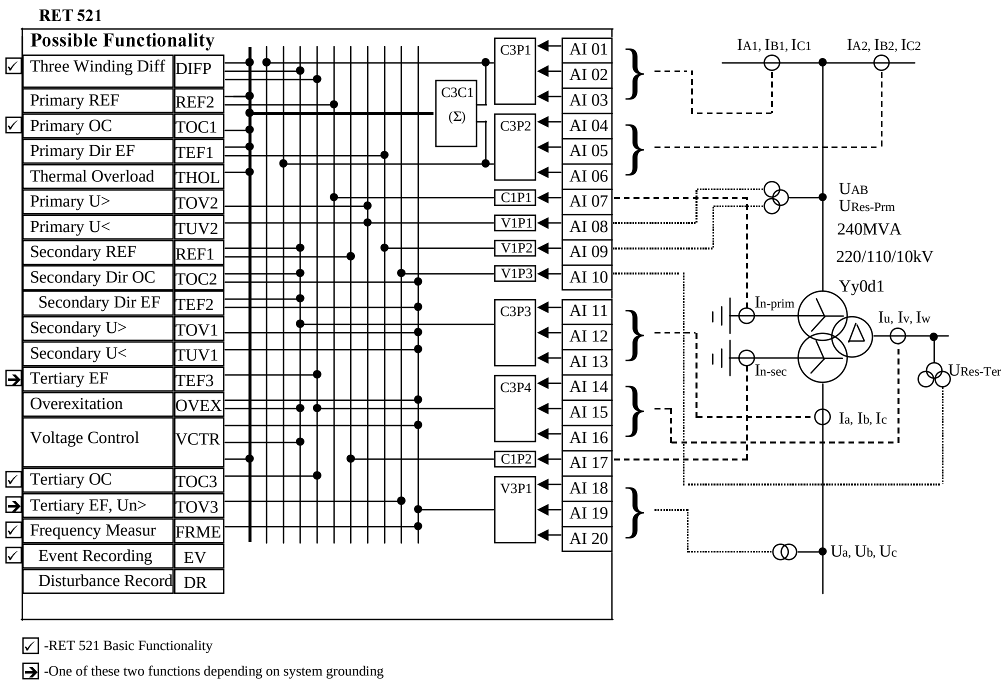
9.2 Configuration 2 (2I + 8U)



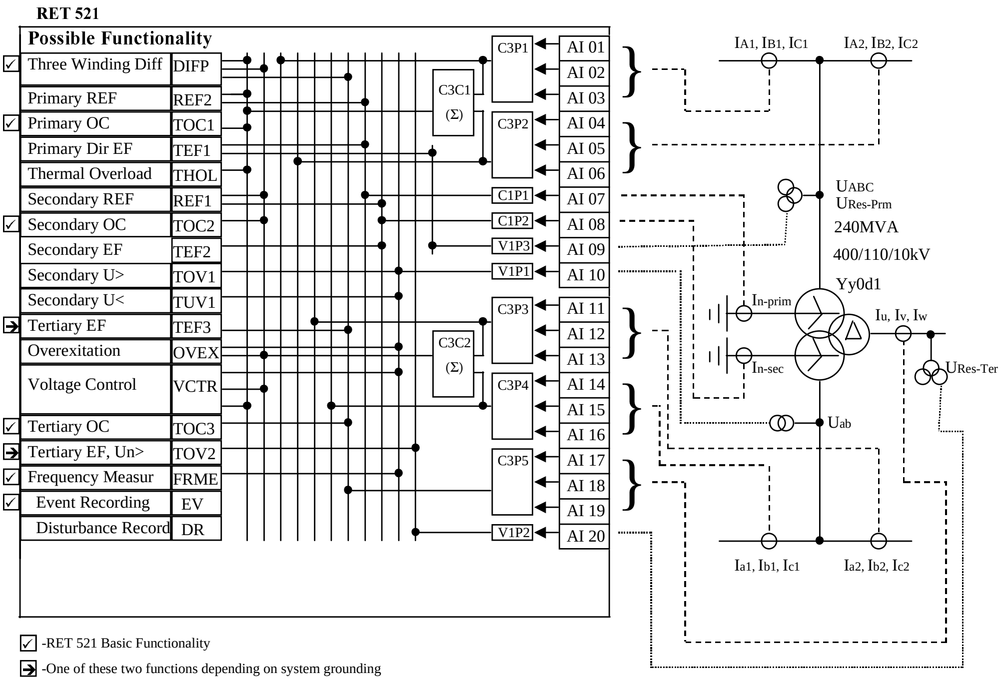
9.3 Configuration 3 (9I + 1U)



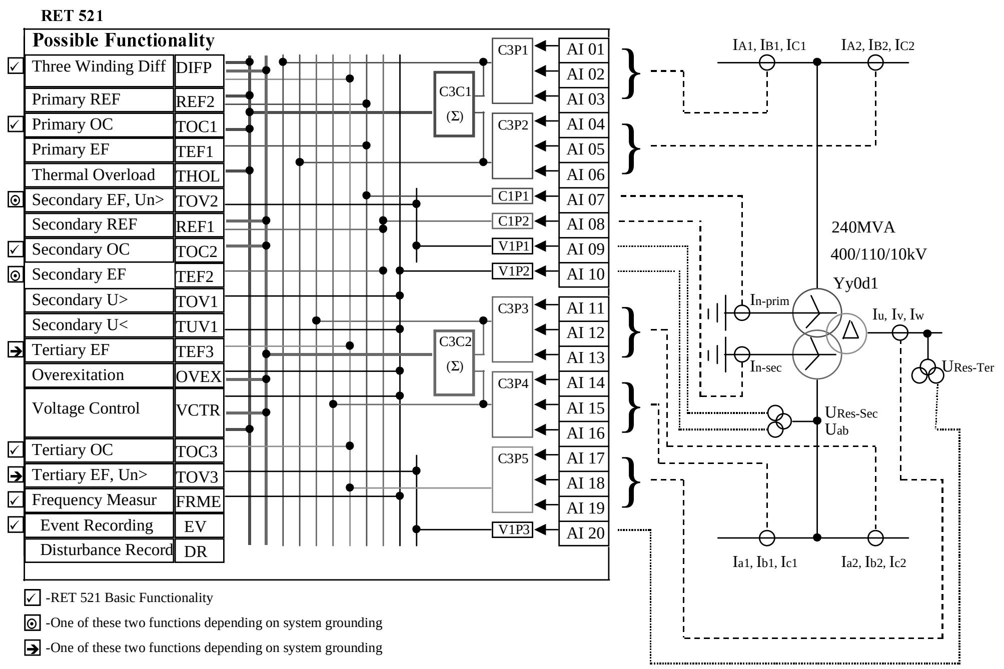
9.4 Configuration No 4 (2x (7I + 3U))



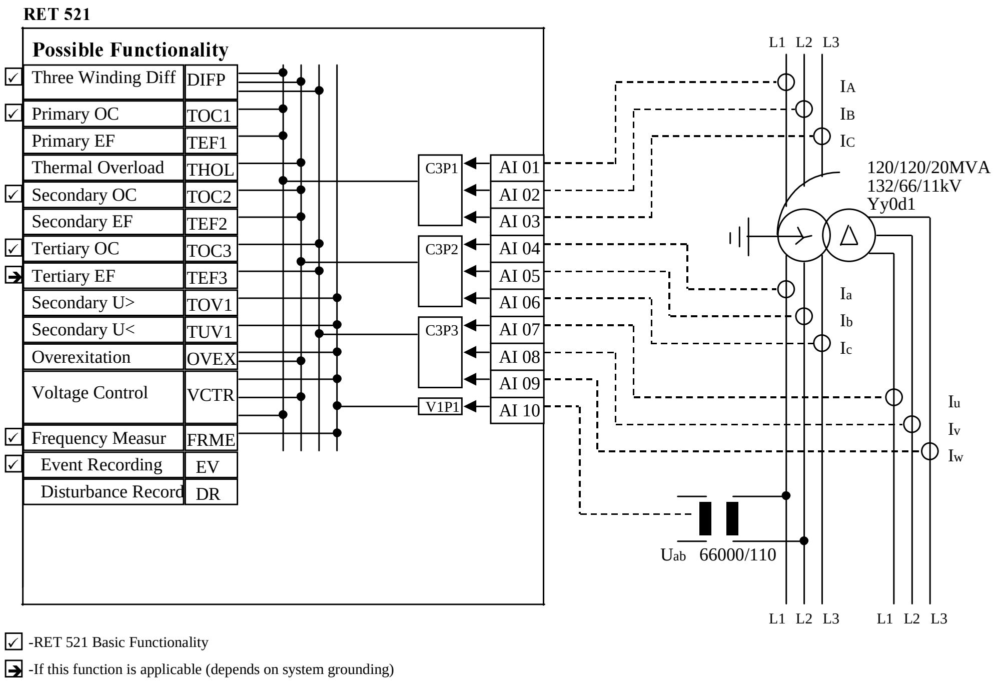
9.5 Configuration No 5 ([8I+2U]&[9I+1U])



9.6 Configuration No 5a ([8I+2U]&[9I+1U])



9.7 Configuration No 6 [9I+1U]



General functionality

10 Tripping logic (TR)

10.1 Summary of function

A trip logic block is provided where up to sixteen input signals can be gated together in an or-gate and then connected to e.g. a trip output relay. Furthermore up to twelve individual trip logic blocks exist so that as many individual output relays can be managed. Each block has been provided with possibility to set a minimum pulse length of the trip signal.

10.2 Description of logic

There are 12 instances (equal pieces) available of the trip logic function, each with the same logic diagram and function block appearance in CAP configuration tool. The text, TRxx-(....,..), on the top of the function block is showing the function block name, TR, together with the instance number, xx, and details of the execution order and execution cycle time. How many of these 12 instances that are needed in an individual terminal is depending on configuration requirements.

Each trip logic instance has 16 equal logic inputs, INPUT01 to INPUT16, to an or-gate.

A settable time pulse circuit is available, which will make sure that a minimum duration of the output trip pulse is achieved for a short activation of an input signal. The settable time can be set to zero seconds, when no extra delay at reset of an input signal is allowed.

A blocking input is available which, when activated, will inhibit an eventual trip output. This blocking input does not reset the time pulse circuit if this did not time out. To securely block the output, the BLOCK must be activated at least as long as the SET-PULSE time setting and also at least as long as any input signal is active.

The inputs and outputs can only be connected with the help of the CAP configuration tool to the outputs and inputs of other function blocks. The time setting, SET-PULSE, of the time pulse circuit will also be made by the CAP configuration tool.

10.3 Logic diagram

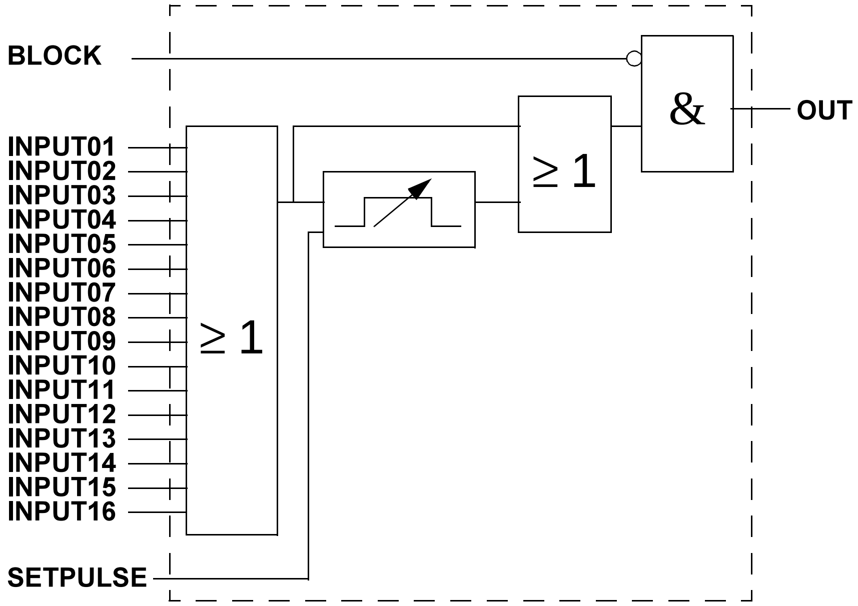


Fig. 10 Logic diagram of the trip logic function

10.4 Function block

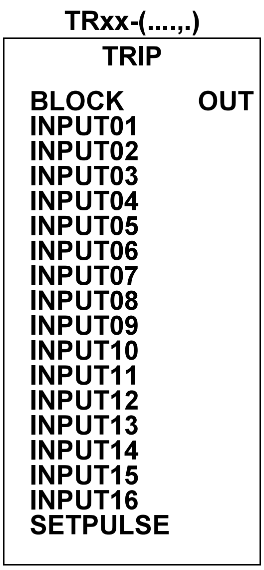


Fig. 11 Function block for trip logic TRxx

10.5 Input and output signals

Table 20: Input signals of trip logic TRxx

In:	Description:
TRxx-BLOCK	Activated BLOCK Inhibits an eventual output signal, OUT. It is not resetting the internal pulse timer.
TRxx-INPUT01	Logic input signal one for trip logic No xx
TRxx-INPUT02	Logic input signal two for trip logic No xx
TRxx-INPUT03	Logic input signal three for trip logic No xx
TRxx-INPUT04	Logic input signal four for trip logic No xx
TRxx-INPUT05	Logic input signal five for trip logic No xx
TRxx-INPUT06	Logic input signal six for trip logic No xx
TRxx-INPUT07	Logic input signal seven for trip logic No xx
TRxx-INPUT08	Logic input signal eight for trip logic No xx
TRxx-INPUT09	Logic input signal nine for trip logic No xx
TRxx-INPUT10	Logic input signal ten for trip logic No xx
TRxx-INPUT11	Logic input signal eleven for trip logic No xx
TRxx-INPUT12	Logic input signal twelve for trip logic No xx
TRxx-INPUT13	Logic input signal thirteen for trip logic No xx
TRxx-INPUT14	Logic input signal fourteen for trip logic No xx
TRxx-INPUT15	Logic input signal fifteen for trip logic No xx
TRxx-INPUT16	Logic input signal sixteen for trip logic No xx

Table 21: Output signal of trip logic TRxx

Out:	Description:
TRxx-OUT	Logic output signal for trip logic No xx. When OUT is activated, the HMI red LED is activated. See the section “How to use the human machine interface” for details.

10.6 Setting parameters and ranges

Table 22: Setting parameter and range of trip logic TRxx

Parameter:	Setting range:	Description:
TRxx-SETPULSE	0.00 - 50.00 s (step 0.01 s) (def. 0.15 s)	Sets the minimum duration in seconds of the output pulse, by setting the time of the internal pulse timer circuit. To be set from CAP tool

11 Terminal hardware structure (THWS)

11.1 Summary of application

I/O modules can be placed in PCI bus and CAN bus slots in the RET 521 transformer terminal. The analogue input module (AIM) is placed in any PCI bus slot and all other I/O modules can be placed in any CAN bus slot. The hardware reconfiguration of the product can easily be made from the graphical configuration tool, CAP tool.

11.2 Summary of function

The I/O system configuration means the function to add, remove, or move I/O modules in the RET 521 transformer terminal. The I/O modules can be connected to two different I/O-busses in the terminal. These are the PCI and the CAN. The analogue input module (AIM) is connected to the PCI bus and all the other I/O modules are connected to the CAN bus.

11.3 Description of logic

11.3.1 Analogue input module (AIM)

The analogue input module is represented by a function block AIMx, where x = 1 or 2. The AIMx function block is connected to the THWS (Terminal Hardware Structure) function block to define the slot position of the AIM module. The AIM module has 10 inputs. These inputs appear as both positive and negative output values on the AIMx function block. The AIMx function blocks can be configured with the function selector in the CAP configuration tool to get three different types. The difference between the types is the number of current and voltage inputs.

- Type 1 has 9 current inputs and 1 voltage input.
- Type 2 has 8 current inputs and 2 voltage inputs.
- Type 3 has 7 current inputs and 3 voltage inputs.

Every input can be given a name with up to 13 characters from the CAP configuration tool.

Parameters not settable from the graphical tool refer to a separate document describing the analog input module.

11.3.2 Binary input module (BIM)

The binary input module has 16 inputs. These inputs appear as outputs on the IOxx function block. The BIM supervises oscillating input signals. These oscillation blocking/release parameters are set from the SMS or from the built-in HMI. Every input can be given a name with up to 13 characters from the CAP configuration tool.

11.3.3 Binary output module (BOM)

The binary output module has 24 outputs. These outputs appear as inputs on the IOxx function block. The outputs are used in pairs when used as command outputs. Activation of the BLKOUT input, resets and blocks the outputs. Every output can be given a name with up to 13 characters from the CAP configuration tool.

11.3.4 Input/output module (IOM)

The input/output module has 8 inputs and 12 outputs. The functionality of the oscillating input blocking that is available on BIM and of the supervised outputs on BOM are not available on this module. Activation of the BLKOUT input, reset and block the outputs. Every input and output can be given a name with up to 13 characters from the CAP configuration tool.

11.3.5 mA input module (MIM)

The mA input module has 6 inputs for mA signals. The POSITION input is located on the first MIM channel, as well as functionality for on-load tap-changer (OLTC) tap position reading, for each MIM module. If the configuration is incorrect, these outputs are set:

- ERROR output on the first MIM channel (MI11) of that MIM
- INPUTERR outputs on all MIM channels of that MIM

For more information about the mA input module including the OLTC functionality and the signal list and setting table, refer to a separate document describing the mA input module.

11.3.6 Terminal hardware structure (THWS)

The THWS function block has 9 outputs in the RET 521 product, which equals the number of available slots. The CANPxx outputs are connected to the POSITION input of the BIMs, BOMs, IOMs, or MIMs and the PCIPxx outputs are connected to the POSITION input of the AIMs.

11.4 Function block

11.4.1 Analogue input module (AIM)

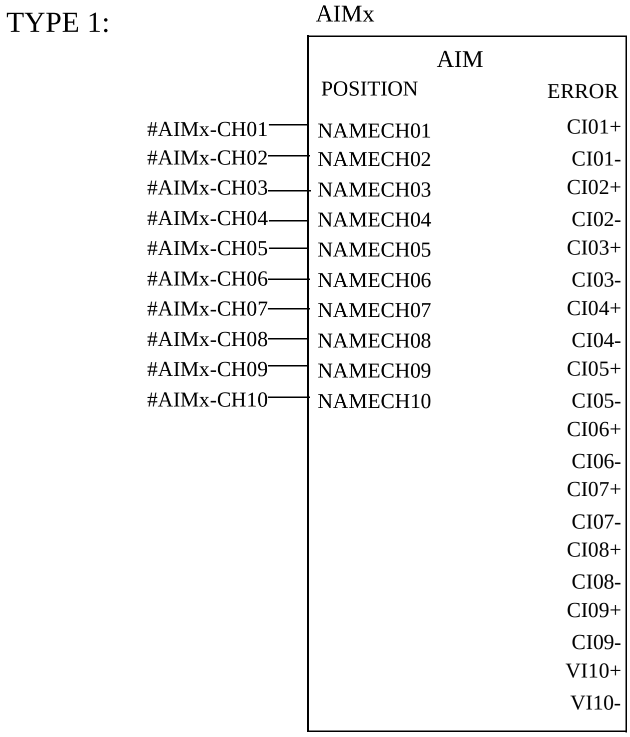


Fig. 12 Function block for the analogue input module (AIM) type 1

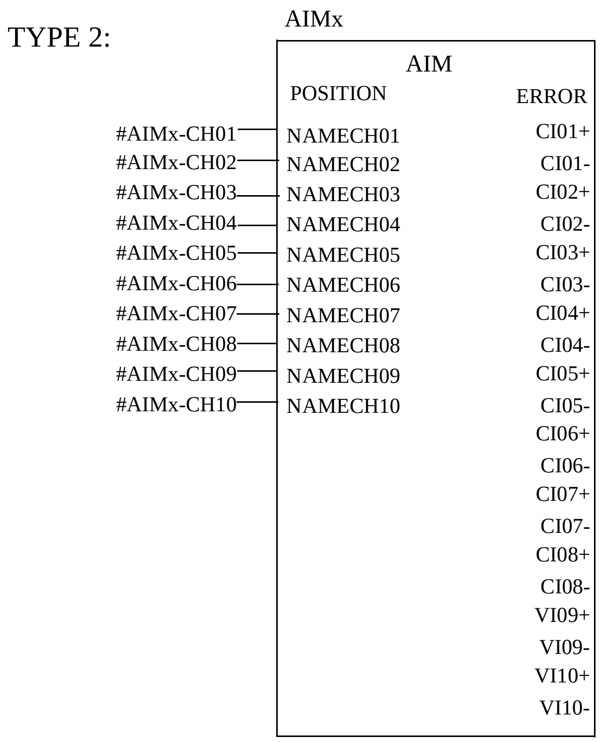


Fig. 13 Function block for the analogue input module (AIM) type 2

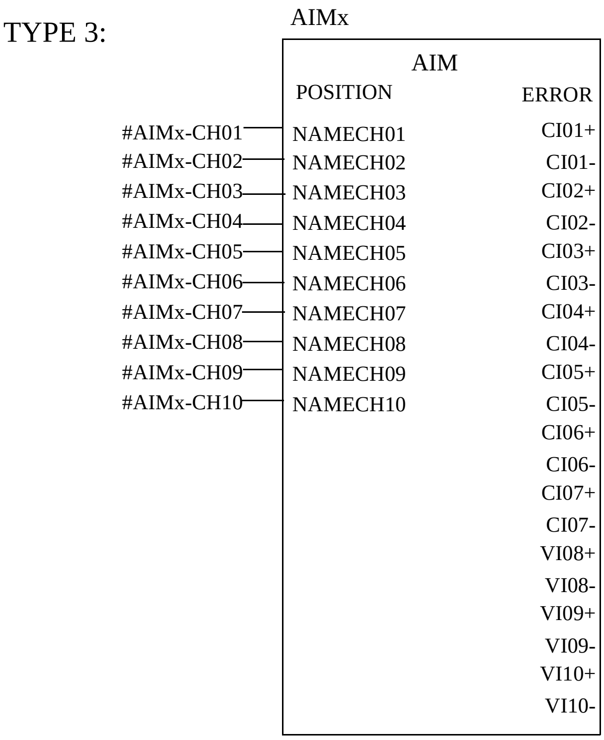


Fig. 14 Function block for the analogue input module (AIM) type 3

11.4.2 Binary input module (BIM)

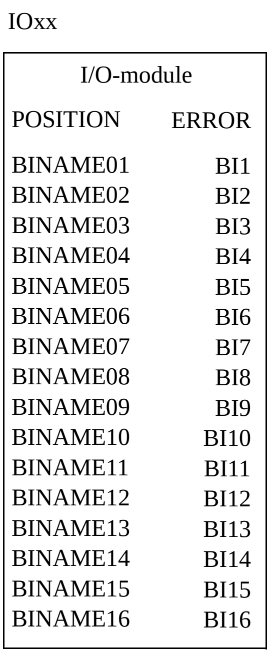


Fig. 15 Function block for the binary input module (BIM)

11.4.3 Binary output module (BOM)

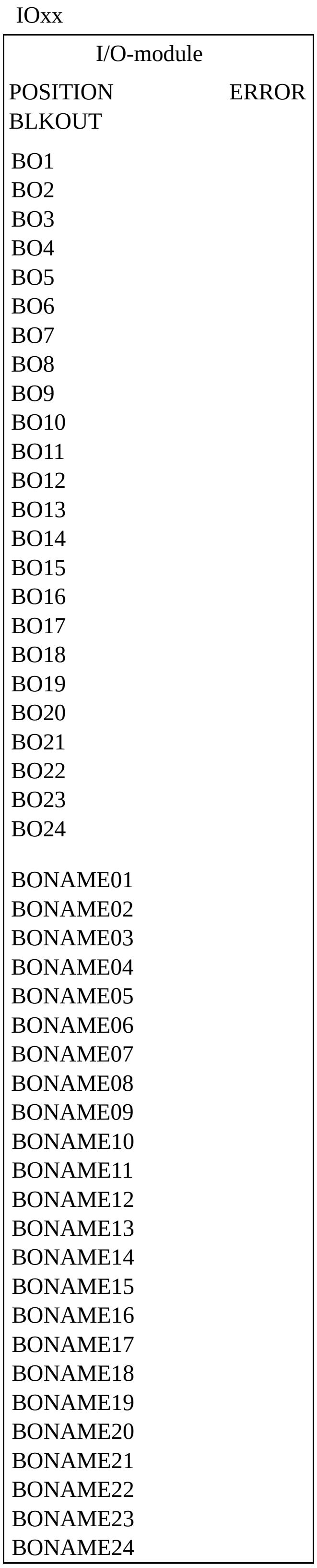


Fig. 16 Function block for the binary output module (BOM)

11.4.4 Input/output module (IOM)

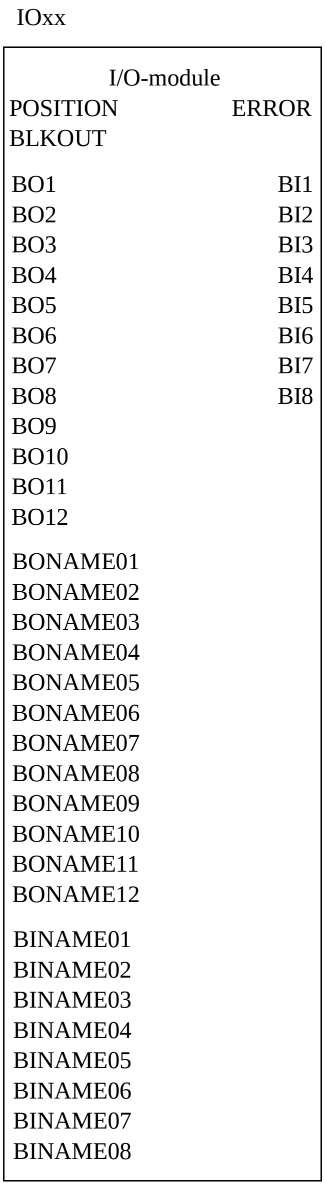
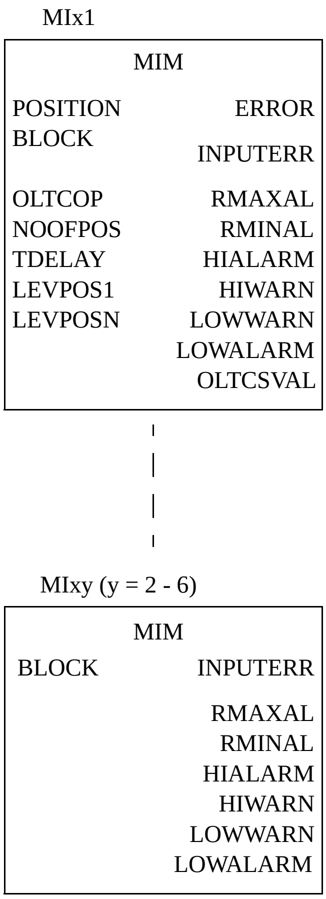


Fig. 17 Function block for the input/output module (IOM)

11.4.5 mA input module (MIM)



x = 1 for a RET terminal

Fig. 18 Function block for the mA input module (MIM)

11.4.6 Terminal HW structure (THWS)

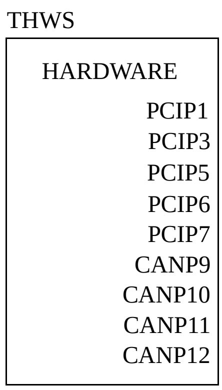


Fig. 19 Function block for the terminal hardware structure module (THWS)

11.5 Input and output signals

Table 23: Signal list for binary input module (BIM), binary output module (BOM), and input/output module (IOM)

In:	Description:
IOxx-POSITION	Slot position input of the I/O module. Is connected to a CAN slot position output of the THWS function block.
IOxx-BLKOUT	Input to reset and block the outputs, applicable for IOM and BOM
IOxx-BOyy	Binary output No. yy, applicable for IOM and BOM.
Out:	**Description:**
IOxx-BIy	Binary input No. yy, applicable for IOM and BIM.
IOxx-ERROR	Status of the I/O module. Is activated if the I/O module is failed.

Table 24: Signal list for analogue input module (AIM), (x = 1, 2)

In:	Description:
AIMx-POSITION	Slot position input of the AIM module No. x. Is connected to PCI slot position P3 or P7 output of the THWS function block.
Out:	**Description:**
AIMx-CIyy+	Current input, positive, for AIM No. x where yy = 01 to 09 for type 1, yy = 01 to 08 for type 2, and yy = 01 to 07 for type 3.

Table 24: Signal list for analogue input module (AIM), (x = 1, 2)

AIMx-CIyy-	Current input, negative, for AIM No. x where yy = 01 to 09 for type 1, yy = 01 to 08 for type 2, and yy = 01 to 07 for type 3.
AIMx-VIyy+	Voltage input, positive, for AIM No. x where yy = 10 for type 1, yy = 09 and 10 for type 2, and yy = 08 to 10 for type 3.
AIMx-VIyy-	Voltage input, negative, for AIM No. x where yy = 10 for type 1, yy = 09 and 10 for type 2, and yy = 08 to 10 for type 3.
AIMx-ERROR	Status of the AIM module. Is activated if the AIM module is failed.

Table 25: Signal list for terminal hardware structure block (THWS)

Out:	Description:
THWS-PCIPz	I/O module located in slot number z for the PCI bus. z = 1, 3, 5, 6 and 7. Is connected to the I/O module function block for AIM.
THWS-CANPzz	I/O module located in slot number zz for the CAN bus. zz = 10, 11 and 12. Is connected to the I/O module function block for BIM, BOM, IOM, and MIM.

11.6 Setting parameters and ranges

Table 26: Setting table for binary input module (BIM), binary output module (BOM), and input/output module (IOM)

Parameter:	Setting range:	Description:
IOxx-BINAMEyy	13 characters	Name of binary input No. yy, used for BIM and IOM. To be set from CAP tool.
IOxx-BONAMEyy	13 characters	Name of binary output No. yy, used for BOM and IOM. To be set from CAP tool.
OscBlock	1-40 Hz	Oscillation blocking frequency, common for all channels on I/O module BIM. To be set from SMS or built-in MMI.
OscRel	1-40 Hz	Oscillation release frequency, common for all channels on I/O module BIM. To be set from SMS or built-in MMI.
Operation	On, Off	I/O module in operation. Operation Off puts the I/O module in a non-active state. To be set from SMS or built-in MMI.

Table 27: Setting table for analogue input module (AIM)

Parameter:	Setting range:	Description:
AIMx-NAMECHyy	13 characters	Name of the analogue input channel No. yy, where yy = 01 to 10 and x = 1 or 2. To be set from CAP tool.

11.7 Service report values

Table 28: Service report values for BOM modules

Parameter:	Range:	Step:	Description:
IO01-BO1	0-1		Status of binary output 1
IO01-BO2	0-1		Status of binary output 2
IO01-BO3	0-1		Status of binary output 3
IO01-BO4	0-1		Status of binary output 4
IO01-BO5	0-1		Status of binary output 5
IO01-BO6	0-1		Status of binary output 6
IO01-BO7	0-1		Status of binary output 7
IO01-BO8	0-1		Status of binary output 8
IO01-BO9	0-1		Status of binary output 9
IO01-BO10	0-1		Status of binary output 10
IO01-BO11	0-1		Status of binary output 11
IO01-BO12	0-1		Status of binary output 12
IO01-BO13	0-1		Status of binary output 13
IO01-BO14	0-1		Status of binary output 14
IO01-BO15	0-1		Status of binary output 15
IO01-BO16	0-1		Status of binary output 16
IO01-BO17	0-1		Status of binary output 17
IO01-BO18	0-1		Status of binary output 18
IO01-BO19	0-1		Status of binary output 19
IO01-BO20	0-1		Status of binary output 20
IO01-BO21	0-1		Status of binary output 21
IO01-BO22	0-1		Status of binary output 22
IO01-BO23	0-1		Status of binary output 23
IO01-BO24	0-1		Status of binary output 24
IO02-BO1	0-1		Status of binary output 1
IO02-BO2	0-1		Status of binary output 2

Table 28: Service report values for BOM modules

Parameter:	Range:	Step:	Description:
IO02-BO3	0-1		Status of binary output 3
IO02-BO4	0-1		Status of binary output 4
IO02-BO5	0-1		Status of binary output 5
IO02-BO6	0-1		Status of binary output 6
IO02-BO7	0-1		Status of binary output 7
IO02-BO8	0-1		Status of binary output 8
IO02-BO9	0-1		Status of binary output 9
IO02-BO10	0-1		Status of binary output 10
IO02-BO11	0-1		Status of binary output 11
IO02-BO12	0-1		Status of binary output 12
IO02-BO13	0-1		Status of binary output 13
IO02-BO14	0-1		Status of binary output 14
IO02-BO15	0-1		Status of binary output 15
IO02-BO16	0-1		Status of binary output 16
IO02-BO17	0-1		Status of binary output 17
IO02-BO18	0-1		Status of binary output 18
IO02-BO19	0-1		Status of binary output 19
IO02-BO20	0-1		Status of binary output 20
IO02-BO21	0-1		Status of binary output 21
IO02-BO22	0-1		Status of binary output 22
IO02-BO23	0-1		Status of binary output 23
IO02-BO24	0-1		Status of binary output 24
IO03-BO1	0-1		Status of binary output 1
IO03-BO2	0-1		Status of binary output 2
IO03-BO3	0-1		Status of binary output 3
IO03-BO4	0-1		Status of binary output 4
IO03-BO5	0-1		Status of binary output 5
IO03-BO6	0-1		Status of binary output 6
IO03-BO7	0-1		Status of binary output 7
IO03-BO8	0-1		Status of binary output 8
IO03-BO9	0-1		Status of binary output 9
IO03-BO10	0-1		Status of binary output 10
IO03-BO11	0-1		Status of binary output 11
IO03-BO12	0-1		Status of binary output 12
IO03-BO13	0-1		Status of binary output 13
IO03-BO14	0-1		Status of binary output 14
IO03-BO15	0-1		Status of binary output 15

Table 28: Service report values for BOM modules

Parameter:	Range:	Step:	Description:
IO03-BO16	0-1		Status of binary output 16
IO03-BO17	0-1		Status of binary output 17
IO03-BO18	0-1		Status of binary output 18
IO03-BO19	0-1		Status of binary output 19
IO03-BO20	0-1		Status of binary output 20
IO03-BO21	0-1		Status of binary output 21
IO03-BO22	0-1		Status of binary output 22
IO03-BO23	0-1		Status of binary output 23
IO03-BO24	0-1		Status of binary output 24
IO04-BO1	0-1		Status of binary output 1
IO04-BO2	0-1		Status of binary output 2
IO04-BO3	0-1		Status of binary output 3
IO04-BO4	0-1		Status of binary output 4
IO04-BO5	0-1		Status of binary output 5
IO04-BO6	0-1		Status of binary output 6
IO04-BO7	0-1		Status of binary output 7
IO04-BO8	0-1		Status of binary output 8
IO04-BO9	0-1		Status of binary output 9
IO04-BO10	0-1		Status of binary output 10
IO04-BO11	0-1		Status of binary output 11
IO04-BO12	0-1		Status of binary output 12
IO04-BO13	0-1		Status of binary output 13
IO04-BO14	0-1		Status of binary output 14
IO04-BO15	0-1		Status of binary output 15
IO04-BO16	0-1		Status of binary output 16
IO04-BO17	0-1		Status of binary output 17
IO04-BO18	0-1		Status of binary output 18
IO04-BO19	0-1		Status of binary output 19
IO04-BO20	0-1		Status of binary output 20
IO04-BO21	0-1		Status of binary output 21
IO04-BO22	0-1		Status of binary output 22
IO04-BO23	0-1		Status of binary output 23
IO04-BO24	0-1		Status of binary output 24

Table 29: Service report values for MIM

Parameter:	Range:	Step:	Description:
MI11-Oltc	0 - 64	1	Service value OLTC MIM1
MI11-Value	-9999.99 - 9999.99	0.01	Service value input 1
MI12-Value	-9999.99 - 9999.99	0.01	Service value input 2
MI13-Value	-9999.99 - 9999.99	0.01	Service value input 3
MI14-Value	-9999.99 - 9999.99	0.01	Service value input 4
MI15-Value	-9999.99 - 9999.99	0.01	Service value input 5
MI16-Value	-9999.99 - 9999.99	0.01	Service value input 6

12 Activation of setting groups (GRP)

12.1 Summary of function

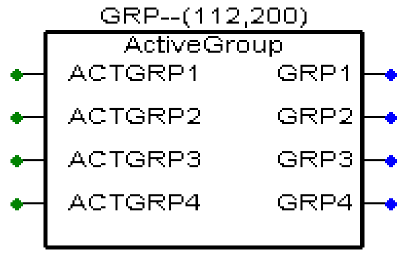
The terminal have four independent groups (sets) of setting parameters. These groups can be activated at any time, by using the HMI, SMS/SCS or by connecting binary inputs to the function block GRP. Each input is configurable to any of the binary inputs in the terminal. Configuration must be performed in the CAP configuration tool. The number of the signals configured must correspond to the number of the setting groups to be controlled by the external signals (contacts).

The voltage need not be permanently present on one binary input. Any pulse, which must be longer than 400 ms, activates the corresponding setting group. The group remains active until some other command, issued either through one of the binary inputs or by other means (local HMI, SMS, SCS), activates another group.

One or more inputs can be activated at the same time. If a function is represented in two different groups and both the groups are active, the group with lowest identity has priority. This means that group 2 has higher priority than group 4 etc.

The block has got four signal outputs (GRPx) to indicate which setting group that currently is active. This might be utilised in a control system which needs a receipt that a setting group change was successfully carried through.

12.2 Function block



12.3 Input and output signals

Table 30:

In:	Description:
ACTGRP1	Active Group-Select setting group 1 as active group
ACTGRP2	Active Group-Select setting group 2 as active group
ACTGRP3	Active Group-Select setting group 3 as active group
ACTGRP4	Active Group-Select setting group 4 as active group

Table 31:

Out:	Description:
GRP1	Active Group-Setting group 1 is active
GRP2	Active Group-Setting group 2 is active
GRP3	Active Group-Setting group 3 is active
GRP4	Active Group-Setting group 4 is active

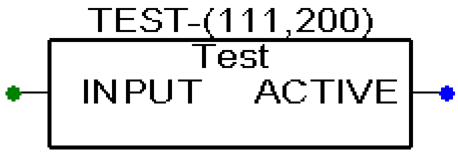
13 Blocking during test (TEST)

13.1 Summary of function

The function block TEST has got one signal input and one signal output. When the input signal gets a logical one, the TEST function block output, ACTIVE, gets a logical one. The terminal will be put into the test mode and all functions that have been set to be blocked in the menu TEST/TestMode/BlockFunctions will be blocked. The flashing yellow LED in the middle on HMI will also indicate that the test mode is on. Output ACTIVE is also set if TestMode is set to on at the HMI.

The TEST block might be used to automatically block functions when a test handle is inserted in a test switch. A contact in the test switch can supply a binary input which in turn is configured to the test block.

13.2 Function block



13.3 Input and output signals

Table 32:

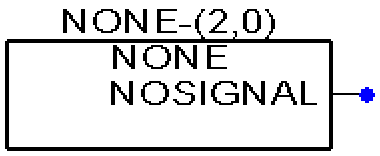
In:	**Description:**
INPUT	Sets terminal in test-mode while input is activated
Out:	**Description:**
ACTIVATE	Terminal in test mode

14 No signal (NONE)

14.1 Summary of function

The function block NONE has got one signal output, for connection to a relevant function block input e g a logical function block or a protection function block

14.2 Function block



14.3 Input and output signals

Table 33:

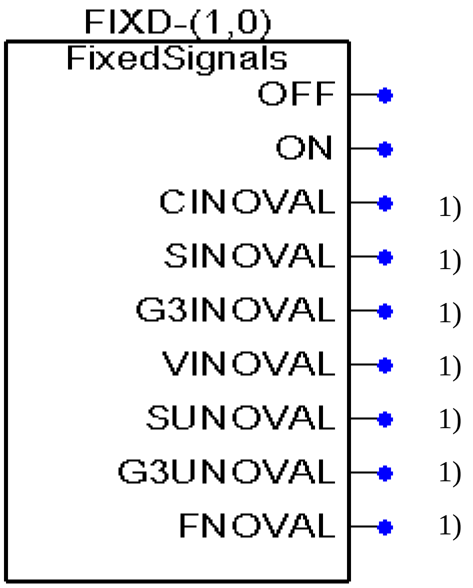
Out:	Description:
NONE	No logical signal for connection to function inputs

15 Fixed signals (FIXD)

15.1 Summary of function

The function block FIXD has got nine signal outputs, for connection to a relevant function block input e g a protection function block or a logic function block. Only the signals OFF and ON are of importance for customer applications.

15.2 Function block



1) For ABB use only

15.3 Input and output signals

Table 34:

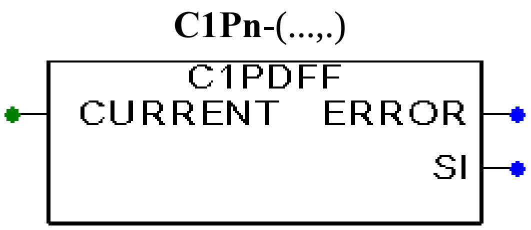
Out:	**Description:**
OFF	Off signal (=0)
ON	On signal (=1)
CINOVAL	Current
SINOVAL	Single phase current
G3INOVAL	Three phase current group
VINOVAL	Voltage
SUNOVAL	Single phase voltage
G3UNOVAL	Three phase voltage group
FNOVAL	Frequency

16 Fourier filter for single phase current (C1P)

16.1 Summary of function

The function block C1Pn where n is a number from 1 to 5 has got one analog signal input, CURRENT, which only can be connected to one of the current channel outputs of the AIM function block. The block C1Pn has got one analog signal output, SI, for connection to a relevant function block input e g a protection function block. It has also got one boolean output signal, ERROR

16.2 Function block



16.3 Input and output signals

Table 35:

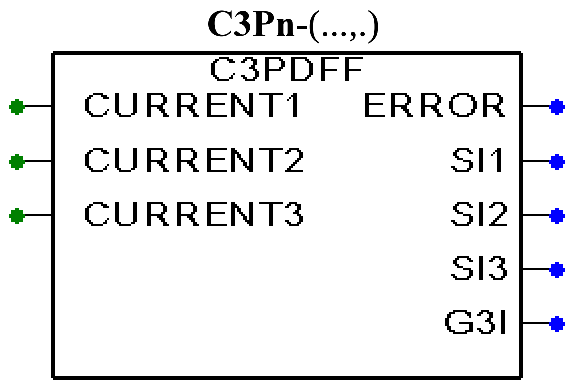
In:	**Description:**
CURRENT	Current, C1Pn
Out:	**Description:**
SI	Single phase current, C1Pn
ERROR	General C1Pn function error

17 Fourier filter for three phase current (C3P)

17.1 Summary of function

The function block C3Pn where n is a number from 1 to 7 has got three analog signal inputs, CURRENTx, which only can be connected to the current channel outputs of the AIM function block. The block C3Pn has got four analog signal outputs, SIx and G3I, for connection to a relevant function block input eg a protection function block. The SIx outputs represents the individual single-phase currents and the G3I output represent the three-phase group. It has also got one boolean output signal, ERROR

17.2 Function block



17.3 Input and output signals

Table 36:

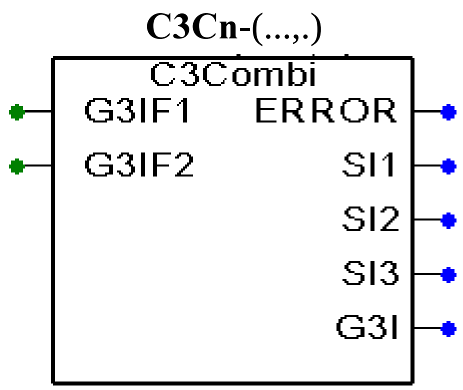
In:	**Description:**
CURRENT1	Current1, C3Pn
CURRENT2	Current2, C3Pn
CURRENT3	Current3, C3Pn
Out:	**Description:**
SI1	Single phase current 1, C3Pn
SI2	Single phase current 2, C3Pn
SI3	Single phase current 3, C3Pn
G3I	Three phase current group, C3Pn
ERROR	General C3Pn function error

18 Sum function for three phase currents (C3C)

18.1 Summary of function

The function block C3Cn where n is a number from 1 to 3 has got two analog three-phase group signal inputs, G3IFx, which only can be connected to the outputs of the C3Pn function block. The block C3Cn has got four analog signal outputs, SIx and G3I, for connection to a relevant function block input eg a protection function block. The SIx outputs represents the sum of the single-phase currents of the two inputs and the G3I output represent the three-phase group sum of the two inputs. The C3Cn function block is used when the sum of two currents e g from a breaker and half configuration is needed for the protection function The C3Cn function block has also got one boolean output signal, ERROR.

18.2 Function block



18.3 Input and output signals

Table 37:

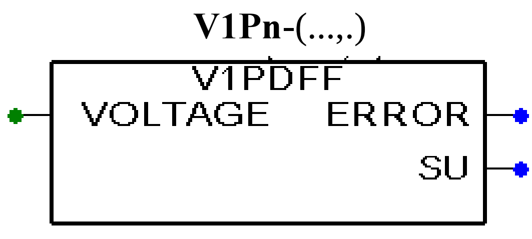
In:	**Description:**
G3IF1	Three phase current group, feeder 1, C3Cn
G3IF2	Three phase current group, feeder 2, C3Cn
Out:	**Description:**
SI1	Single phase current 1, C3Cn
SI2	Single phase current 2, C3Cn
SI3	Single phase current 3, C3Cn
G3I	Three phase current group, C3Cn
ERROR	General C3Cn function error

19 Fourier filter for single phase voltage (V1P)

19.1 Summary of function

The function block V1Pn where n is a number from 1 to 5 has got one analog signal input, VOLTAGE, which only can be connected to one of the voltage channel outputs of the AIM function block. The block V1Pn has got one analog signal output, SU, for connection to a relevant function block input e g a protection function block. It has also got one boolean output signal, ERROR

19.2 Function block



19.3 Input and output signals

Table 38:

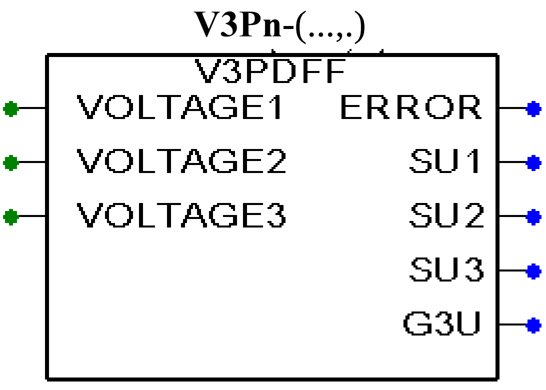
In:	Description:
VOLTAGE	Voltage, V1Pn
Out:	**Description:**
SU	Single phase voltage, V1Pn
ERROR	General V1Pn function error

20 Fourier filter for three phase voltage (V3P)

20.1 Summary of function

The function block V3Pn where n is a number from 1 to 5 has got three analog signal inputs, VOLTAGEx, which only can be connected to the voltage channel outputs of the AIM function block. The block V3Pn has got four analog signal outputs, SUx and G3U, for connection to a relevant function block input e g a protection function block. The SUx outputs represents the individual single-phase voltages and the G3U output represent the three-phase group. It has also got one boolean output signal, ERROR.

20.2 Function block



20.3 Input and output signals

Table 39:

In:	**Description:**
VOLTAGE1	Voltage1, V3Pn
VOLTAGE2	Voltage2, V3Pn
VOLTAGE3	Voltage3, V3Pn
Out:	**Description:**
SU1	Single phase voltage 1, V3Pn
SU2	Single phase voltage 2, V3Pn
SU3	Single phase voltage 3, V3Pn
G3U	Three phase voltage group, V3Pn
ERROR	General V3Pn function error

21 Binary converter (CNV)

21.1 Summary of function

The function block CNV, binary converter, has got three parameter setting inputs, eight signal inputs and two signal outputs. The block is used to convert binary or decimal binary coded signals to their decimal equivalent, when tap position indication is got with the help of coded binary inputs from the IO board.

The setting parameters set the type of coding BIN or BCD and if parity is used or not and the time the bit signal have to be stable before it is accepted. The bit input signals are arranged so that the BIT 1 is the least significant bit and BIT 6 the most significant bit.

The parity input takes care of the parity bit if parity is used. The BIERR signal can be connected to an external incoming error signal for a faulty situation.The output signal VALUE gives the decimal value and the ERROR output shows the error status. The truth table below shows the conversion for BIN and BCD coded signals.

Table 40: BIN and BCD conversion

INPUTS								OUTPUTS			
								BIN coded		BCD coded	
BIT 6 (MSB)	BIT 5	BIT 4	BIT 3	BIT 2	BIT 1 (LSB)	PARITY PARUSE=1	BIERR	VALUE	ERROR	VALUE	ERROR
0	0	0	0	0	0	0	0	0	0	**0**	0
0	0	0	0	0	1	1	0	1	0	**1**	0
0	0	0	0	1	0	1	0	2	0	**2**	0
0	0	0	0	1	1	0	0	3	0	**3**	0
0	0	0	1	0	0	1	0	4	0	**4**	0
0	0	0	1	0	1	0	0	5	0	**5**	0
0	0	0	1	1	0	0	0	6	0	**6**	0
0	0	0	1	1	1	1	0	7	0	**7**	0
0	0	1	0	0	0	1	0	8	0	**8**	0
0	0	1	0	0	1	0	0	9	0	**9**	0
0	0	1	0	1	0	0	0	10	0	**0**	1
0	0	1	0	1	1	1	0	11	0	**0**	1
0	0	1	1	0	0	0	0	12	0	**0**	1
0	0	1	1	0	1	1	0	13	0	**0**	1
0	0	1	1	1	0	1	0	14	0	**0**	1
0	0	1	1	1	1	0	0	15	0	**0**	1
0	1	0	0	0	0	1	0	16	0	**10**	0
0	1	0	0	0	1	0	0	17	0	**11**	0
0	1	0	0	1	0	0	0	18	0	**12**	0
0	1	0	0	1	1	1	0	19	0	**13**	0
0	1	0	1	0	0	0	0	20	0	**14**	0
0	1	0	1	0	1	1	0	21	0	**15**	0
0	1	0	1	1	0	1	0	22	0	**16**	0
0	1	0	1	1	1	0	0	23	0	**17**	0
0	1	1	0	0	0	0	0	24	0	**18**	0
0	1	1	0	0	1	1	0	24	0	**19**	0
0	1	1	0	1	0	1	0	26	0	**0**	1
0	1	1	0	1	1	0	0	27	0	**0**	1
0	1	1	1	0	0	1	0	28	0	**0**	1
0	1	1	1	0	1	0	0	29	0	**0**	1
0	1	1	1	1	0	0	0	30	0	**0**	1
0	1	1	1	1	1	1	0	31	0	**0**	1
1	0	0	0	0	0	1	0	32	0	**20**	0
1	0	0	0	0	1	0	0	33	0	**21**	0
1	0	0	0	1	0	0	0	34	0	**22**	0
1	0	0	0	1	1	1	0	35	0	**23**	0
1	0	0	1	0	0	0	0	36	0	**24**	0
1	0	0	1	0	1	1	0	37	0	**24**	0
1	0	0	1	1	0	1	0	38	0	**26**	0
1	0	0	1	1	1	0	0	39	0	**27**	0

Table 40: BIN and BCD conversion (Continued)

INPUTS								OUTPUTS			
								BIN coded		BCD coded	
BIT 6 (MSB)	BIT 5	BIT 4	BIT 3	BIT 2	BIT 1 (LSB)	PARITY PARUSE=1	BIERR	VALUE	ERROR	VALUE	ERROR
1	0	1	0	0	0	0	0	40	0	**28**	0
1	0	1	0	0	1	1	0	41	0	**29**	0
1	0	1	0	1	0	1	0	41	0	**0**	1
1	0	1	0	1	1	0	0	43	0	**0**	1
1	0	1	1	0	0	1	0	44	0	**0**	1
1	0	1	1	0	1	0	0	45	0	**0**	1
1	0	1	1	1	0	0	0	46	0	**0**	1
1	0	1	1	1	1	1	0	47	0	**0**	1
1	1	0	0	0	0	0	0	48	0	**30**	0
1	1	0	0	0	1	1	0	49	0	**31**	0
1	1	0	0	1	0	1	0	50	0	**32**	0
1	1	0	0	1	1	0	0	51	0	**33**	0
1	1	0	1	0	0	1	0	52	0	**34**	0
1	1	0	1	0	1	0	0	53	0	**35**	0
1	1	0	1	1	0	0	0	54	0	**36**	0
1	1	0	1	1	1	1	0	55	0	**37**	0
1	1	1	0	0	0	1	0	56	0	**38**	0
1	1	1	0	0	1	0	0	57	0	**39**	0
1	1	1	0	1	0	0	0	58	0	**0**	1
1	1	1	0	1	1	1	0	59	0	**0**	1
1	1	1	1	0	0	0	0	60	0	**0**	1
1	1	1	1	0	1	1	0	61	0	**0**	1
1	1	1	1	1	0	1	0	62	0	**0**	1
1	1	1	1	1	1	0	0	63	0	**0**	1
-	-	-	-	-	-	-	-	-	-	**-**	-
1	1	0	1	0	0	**0 (wrong)**	0	0	1	**0**	1
1	1	0	1	0	0	1	**1**	0	1	**0**	1

21.2 Function block

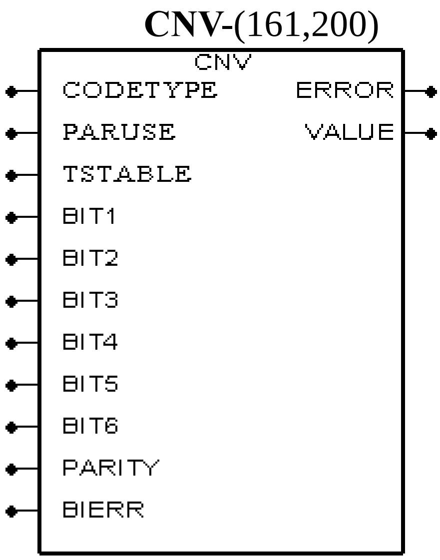


Fig. 20

21.3 Input and output signals

Table 41:

In:	**Description:**
BIT1	Bit 1 Least Sign Bit, CNV
BIT2	Bit 2 in binary word, CNV
BIT3	Bit 3 in binary word, CNV
BIT4	Bit 4 in binary word, CNV
BIT5	Bit 5 in binary word, CNV
BIT6	Bit 6 in binary word, CNV
PARITY	Parity bit, CNV
BIERR	Error status, CNV
Out:	**Description:**
ERROR	General CNV function error
VALUE	Value of conversion, CNV

21.4 Setting parameters and ranges

Table 42:

Parameter:	Setting range:	Description:
CNV--CODETYPE	BIN, BCD	Type of binary code
CNV--PARUSE	OFF, ON	Even parity check
CNV--TSTABLE	0.0 - 10.0s	Required stable time for inputs

22 Configurable logic (CL)

22.1 Summary of application

Additional logic circuits in the form of AND-, OR-gates with inverter possibility, inverters, timers, and pulse functions are available and can be combined by the user to suit particular requirements.

22.2 Summary of function

The configuration logic contains the following functional blocks: 20 inverters, 40 OR, 40 AND, 10 timers, and 10 pulse-timers. The configuration and parameter setting are performed from the CAP configuration tool.

22.3 Description of logic

22.3.1 General

In the RET 521 terminal, 20 inverters, 40 OR, 40 AND, 15 timers, 10 long timers, 20 pulse-timers, 10 set-reset gates with memory and 6 MOVE function blocks are available.

- 4 inverters, 8 OR, 8 AND, 7 timers, and 12 pulse-timers are executed in a loop with maximum speed.
- 4 inverters, 8 OR, 8 AND, 2 timers, 2 pulse-timers, and 2 MOVE are executed in a loop with mediate speed.
- 12 inverters, 24 OR, 24 AND, 6 timers, 10 timerlong, 6 pulse-timers, 10 SRM gates and 4 MOVE are executed in a loop with lowest speed.

Refer to other document describing the execution details.

22.3.2 Inverter (INV)

The configuration logic Inverter (INV) (Fig. 21) has one input, designated IVnn-INPUT, where nn runs from 01 to 20 and presents the serial number of the block. Each INV circuit has one output, IVnn-OUT.

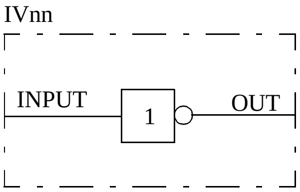


Fig. 21 Block diagram of the inverter (INV) function

22.3.3 OR

The configuration logic OR gate (Fig. 22) has six inputs, designated Onnn-INPUTm, where nnn runs from 001 to 040 and presents the serial number of the block, and m presents the serial number of the inputs in the block. Each OR circuit has two outputs, Onnn-OUT and Onnn-NOUT (inverted).

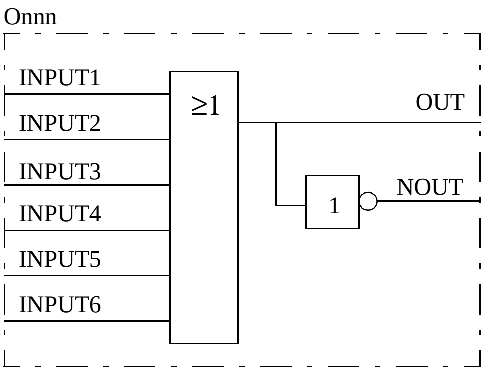


Fig. 22 Block diagram of the OR function

22.3.4 AND

The configuration logic AND gate (Fig. 23) has four inputs (one of them inverted), designated Annn-INPUTm (Annn-INPUT4N is inverted), where nnn runs from 001 to 040 and presents the serial number of the block, and m presents the serial number of the inputs in the block. Each AND circuit has two outputs, Annn-OUT and Annn-NOUT (inverted).

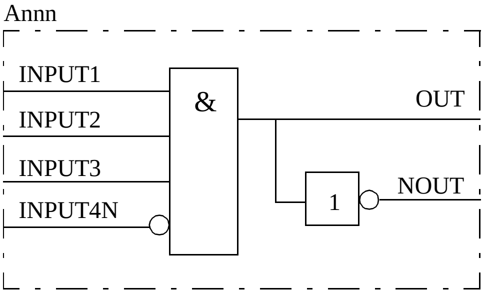


Fig. 23 Block diagram of the AND function

22.3.5 Timer

The configuration logic TM timer, delayed at pick-up and at drop-out (Fig. 24), has a settable time delay TMnn-T between 0 and 60.000 s in steps of 0.001 s, settable from CAP configuration tool. The input signal for each time delay block has the designation TMnn-INPUT, where nn runs from 01 to 15 and presents the serial number of the logic block. The output signals of each time delay block are TMnn-ON and TMnn-OFF. The first one belongs to the timer delayed on pick-up and the second one to the timer delayed on drop-out. Both timers within one block always have the same setting.

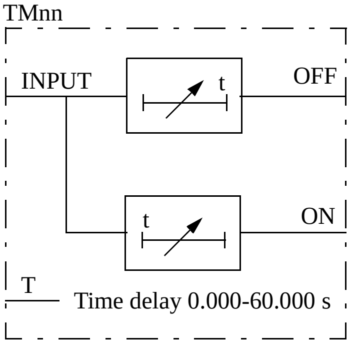


Fig. 24 Block diagram of the Timer function

22.3.6 TimerLong

The configuration logic TL timer, delayed at pick-up and at drop-out (Fig. 25), has a settable time delay TLnn-T between 0.0 and 90000.0 s in steps of 0.1 s, settable from CAP configuration tool. The input signal for each time delay block has the designation TLnn-INPUT, where nn runs from 01 to 10 and presents the serial number of the logic block. The output signals of each time delay block are TLnn-ON and TLnn-OFF. The first one belongs to the timer delayed on pick-up and the second one to the timer delayed on drop-out. Both timers within one block always have the same setting.

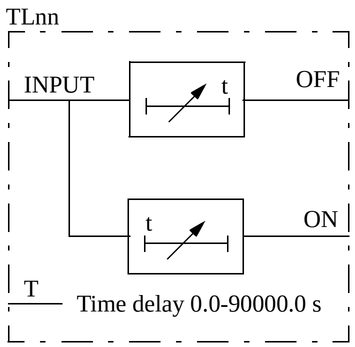


Fig. 25 Block diagram of the TimerLong function

22.3.7 Pulse

The configuration logic pulse timer TP (Fig. 26), has a settable length of a pulse between 0.000 s and 60.000 s in steps of 0.001 s, settable from CAP configuration tool. The input signal for each pulse timer has the designation TPnn-INPUT, where nn runs from 01 to 20 and presents the serial number of the logic block. Each pulse timer has one output, designated by TPnn-OUT. The pulse timer is not retriggable, that is, it can be restarted only when the time T has elapsed.

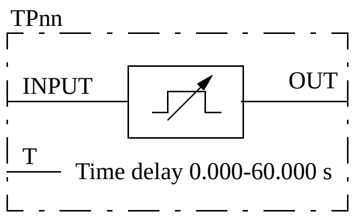


Fig. 26 Block diagram of the Pulse function

22.3.8 Set-Reset with memory

The configuration logic Set-Reset (SM) with memory function (Fig. 27) has two inputs designated SMnn-SET and SMnn-RESET, where nn runs from 0 to 10 and presents the serial number of the block. Each SM circuit has two outputs, SMnn-OUT and SMnn-NOUT (inverted). The output (OUT) is set to 1 if the input (SET) is set to 1, if the input (RESET) is set to 0. If the reset input is set to 1, the output is unconditionally reset to 0. If the third input MemOn is set to 1, the states of the outputs (OUT) and (NOUT) are stored in a nonvolatile memory. At a power up or restart of the terminal the states in that case will be automatically fetched from the nonvolatile memory.

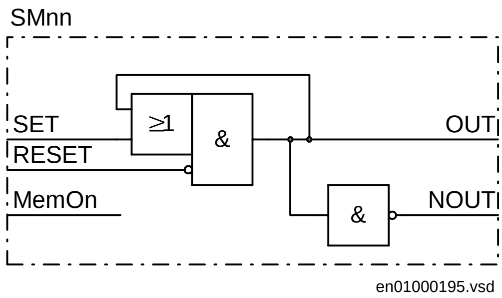


Fig. 27 Block diagram of the Set-Reset function

22.3.9 MOVE

There are two types of MOVE function blocks - MOF located ***F***irst in the slow logic and MOL located ***L***ast in the slow logic. The MOF function blocks are used for signals coming into the slower logic and the MOL function blocks are used for signals going out from the slower logic.

In the RET 521 terminal, the logic is running with three different execution cycle times, maximum, medium and low speed. There are two MOVE blocks (one MOF and one MOL) with 16 signals each available for the medium speed and four MOVE blocks (two MOF and two MOL) for the low speed.

This means that a maximum of 16 signals into and 16 signals out from the medium speed logic and 32 signals into and 32 signals out from the low speed logic can be synchronized. The MOF and MOL function blocks are only a temporary storage for the signals and do not change any value between input and output.

22.4 Function block

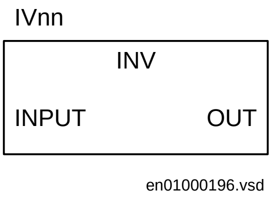


Fig. 28 Simplified terminal diagram of the Inverter function

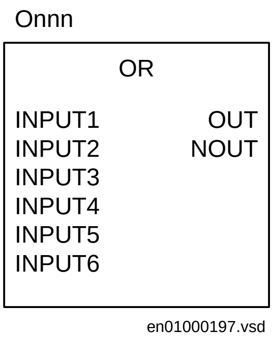


Fig. 29 Simplified terminal diagram of the OR function

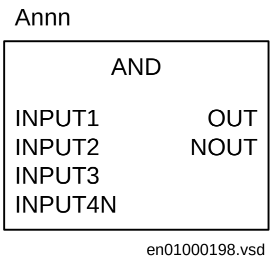


Fig. 30 Simplified terminal diagram of the AND function

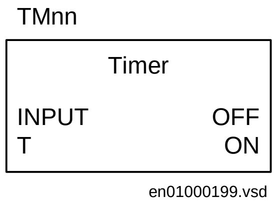


Fig. 31 Simplified terminal diagram of the Timer function

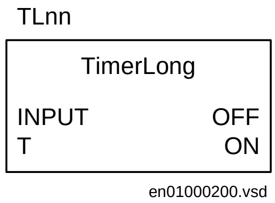


Fig. 32 Simplified terminal diagram of the TimerLong function

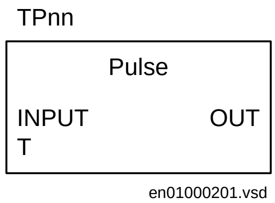


Fig. 33 Simplified terminal diagram of the Pulse function

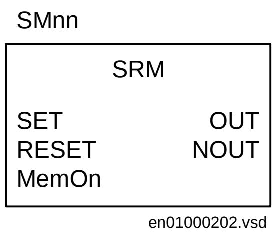


Fig. 34 Simplified terminal diagram of the Set-Reset function

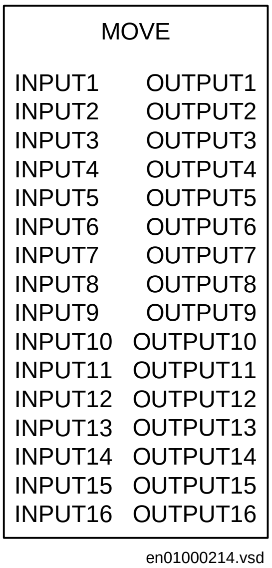


Fig. 35 Simplified terminal diagram of the MOVE First (MOF) function

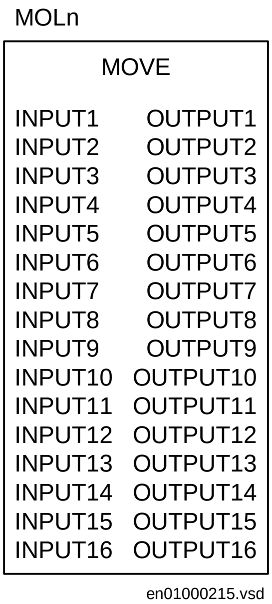


Fig. 36 Simplified terminal diagram of the MOVE Last (MOL) function

22.5 Input and output signals

Table 43: Signal list for the Inverter function

In:	Description:
IVnn-INPUT	Logic INV input to INV gate number nn
Out:	**Description:**
IVnn-OUT	Logic INV output from INV gate number nn

Table 44: Signal list for the OR function

In:	Description:
Onnn-INPUTm	Logic OR input m (m=1-6) to OR gate number nnn
Out:	**Description:**
Onnn-OUT	Output from OR gate number nnn
Onnn-NOUT	Inverted output from OR gate number nnn

Table 45: Signal list for the AND function

In:	Description:
Annn-INPUTm	Logic AND input m (m=1-3) to AND gate number nnn
Annn-INPUT4N	Logic AND input 4 (inverted) to AND gate number nnn
Out:	**Description:**
Annn-OUT	Output from AND gate number nnn
Annn-NOUT	Inverted output from AND gate number nnn

Table 46: Signal list for the Timer function

In:	Description:
TMnn-INPUT	Logic Timer input to timer number nn
Out:	**Description:**
TMnn-OFF	Output from timer number nn, Off delay
TMnn-ON	Output from timer number nn, On delay

Table 47: Signal list for the TimerLong function

In:	Description:
TLnn-INPUT	Logic Timer input to timer number nn
Out:	**Description:**
TLnn-OFF	Output from timer number nn, Off delay
TLnn-ON	Output from timer number nn, On delay

Table 48: Signal list for the Pulse function

In:	Description:
TPnn-INPUT	Logic pulse timer input to pulse timer number nn
Out:	**Description:**
TPnn-OUT	Output from pulse timer number nn

Table 49: Signal list for the Set-Reset gate with memory

In:	Description:
SMnn-SET	SET-input to gate number nn
SMnn-RESET	RESET-input to gate number nn
SMnn-MemOn	Memory usage Off/On of gate number nn
Out:	**Description:**
SMnn-OUT	Output from Set-Reset gate number nn
SMnn-NOUT	Negated output from Set-Reset gate number nn

Table 50: Signal list for the MOVE First (MOF) function

In:	Description:
MOFn-INPUTm	Logic MOVE input m (m=1-16) to MOF number n
Out:	**Description:**
MOFn-OUTPUTm	Output m (m=1-16) from MOF number n

Table 51: Signal list for the MOVE Last (MOL) function

In:	Description:
MOLn-INPUTm	Logic MOVE input m (m=1-16) to MOL number n
Out:	**Description:**
MOLn-OUTPUTm	Output m (m=1-16) from MOL number n

22.6 Setting parameters and ranges

Table 52: Setting table for the Timer function

Parameter:	Setting range:	Description:
TMnn-T	0.000-60.000 s	Time delay for timer TM number nn. To be set from CAP tool.

Table 53: Setting table for the TimerLong function

Parameter:	Setting range:	Description:
TLnn-T	0.0-90000.0 s	Time delay for timer TL number nn. To be set from CAP tool.

Table 54: Setting table for the Pulse function

Parameter:	Setting range:	Description:
TPnn-T	0.000-60.000 s	Pulse length for pulse timer TP number nn. To be set from CAP tool.

23 Command function (CM/CD)

23.1 Summary of application

The protection and control terminals may be provided with output functions that can be controlled either from a Substation Automation system or from the built-in HMI. The output functions can be used, for example, to control high-voltage apparatuses in switchyards. For local control functions, the built-in HMI can be used. It is also possible to receive data from other terminals via the LON bus and the Command function block.

23.2 Summary of function

The outputs from the Command function blocks can be individually controlled from the operator station, remote-control gateway, or from the built-in HMI. Together with the configuration logic circuits, the user can govern pulses or steady output signals for control purposes within the terminal or via binary outputs.

23.3 Description of logic

23.3.1 General

Two types of command function blocks are available, Single Command and Multiple Command. In the RET 521 terminal, one Single Command function block and up to 20 Multiple Command function blocks are available.

The output signals can be of the types Off, Steady, or Pulse. The setting is done on the MODE input, common for the whole block, from the CAP configuration tool.

0=Off sets all outputs to 0, independent of the values sent from the station level, that is, the operator station or remote-control gateway.

1=Steady sets the outputs to a steady signal 0 or 1, depending on the values sent from the station level.

2=Pulse gives a pulse with a duration equal to one execution cycle of the command function block, if a value sent from the station level is changed from 0 to 1. That means that the configured logic connected to the command function blocks may not have a cycle time longer than the cycle time of the command function block.

23.3.2 Single Command function

The Single Command function block has 16 outputs. The outputs can be individually controlled from the operator station, remote-control gateway, or from the built-in HMI. Each output signal can be given a name with a maximum of 13 characters from the CAP configuration tool.

The output signals, here CDxx-OUT1 to CDxx-OUT16, are then available for configuration to built-in functions or via the configuration logic circuits to the binary outputs of the terminal.

23.3.3 Multiple Command function

The Multiple Command function block has 16 outputs combined in one block, which can be controlled from the operator station, that is, the whole block is sent at the same time from the operator station. One common name, with a maximum of 19 characters for the block, is set from the configuration tool, CAP.

The output signals, here CMxx-OUT1 to CMxx-OUT16, are then available for configuration to built-in functions or via the configuration logic circuits to the binary outputs of the terminal.

23.3.4 Communication between terminals

The Multiple Command function block has a supervision function, which sets the output VALID to 0 if the block did not receive data within an INTERVAL time, that could be set. This function is applicable only during communication between terminals over the LON bus. The INTERVAL input time is set a little bit longer than the interval time set on the Event function block. If INTERVAL=0, then VALID will be 1, that is, not applicable. The MODE input is set to Steady at communication between control terminals and then the data are mapped between the terminals.

23.4 Function block

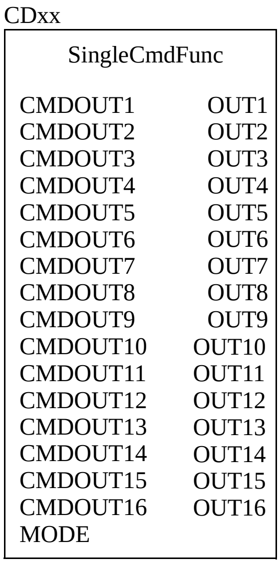


Fig. 37 Simplified terminal diagram of the Single Command function

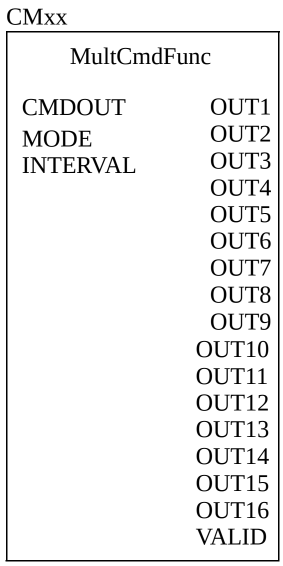


Fig. 38 Simplified terminal diagram of the Multiple Command function

23.5 Input and output signals

Table 55: Signal list for Single Command function No. xx

In:	Description:
CDxx-OUT1	Command output 1 for single command block No xx
CDxx-OUT2	Command output 2 for single command block No xx
CDxx-OUT3	Command output 3 for single command block No xx
CDxx-OUT4	Command output 4 for single command block No xx
CDxx-OUT5	Command output 5 for single command block No xx
CDxx-OUT6	Command output 6 for single command block No xx
CDxx-OUT7	Command output 7 for single command block No xx
CDxx-OUT8	Command output 8 for single command block No xx
CDxx-OUT9	Command output 9 for single command block No xx
CDxx-OUT10	Command output 10 for single command block No xx
CDxx-OUT11	Command output 11 for single command block No xx
CDxx-OUT12	Command output 12 for single command block No xx
CDxx-OUT13	Command output 13 for single command block No xx
CDxx-OUT14	Command output 14 for single command block No xx
CDxx-OUT15	Command output 15 for single command block No xx
CDxx-OUT16	Command output 16 for single command block No xx

Table 56: Signal list for Multiple Command function No. xx

Out:	Description:
CMxx-OUT1	Command output 1 for multiple command block No xx
CMxx-OUT2	Command output 2 for multiple command block No xx
CMxx-OUT3	Command output 3 for multiple command block No xx
CMxx-OUT4	Command output 4 for multiple command block No xx
CMxx-OUT5	Command output 5 for multiple command block No xx
CMxx-OUT6	Command output 6 for multiple command block No xx
CMxx-OUT7	Command output 7 for multiple command block No xx
CMxx-OUT8	Command output 8 for multiple command block No xx
CMxx-OUT9	Command output 9 for multiple command block No xx
CMxx-OUT10	Command output 10 for multiple command block No xx
CMxx-OUT11	Command output 11 for multiple command block No xx
CMxx-OUT12	Command output 12 for multiple command block No xx
CMxx-OUT13	Command output 13 for multiple command block No xx
CMxx-OUT14	Command output 14 for multiple command block No xx
CMxx-OUT15	Command output 15 for multiple command block No xx
CMxx-OUT16	Command output 16 for multiple command block No xx
CMxx-VALID	Received data is valid=1 or invalid=0

23.6 Setting parameters and ranges

Table 57: Setting table for Single Command function No. xx

Parameter:	Setting range:	Description:
CDxx-CMDOUT1	13 characters string	User name for Output 1, to be set from CAP tool or from SMS
CDxx-CMDOUT2	13 characters string	User name for Output 2, to be set from CAP tool or from SMS
CDxx-CMDOUT3	13 characters string	User name for Output 3, to be set from CAP tool or from SMS
CDxx-CMDOUT4	13 characters string	User name for Output 4, to be set from CAP tool or from SMS
CDxx-CMDOUT5	13 characters string	User name for Output 5, to be set from CAP tool or from SMS
CDxx-CMDOUT6	13 characters string	User name for Output 6, to be set from CAP tool or from SMS
CDxx-CMDOUT7	13 characters string	User name for Output 7, to be set from CAP tool or from SMS
CDxx-CMDOUT8	13 characters string	User name for Output 8, to be set from CAP tool or from SMS
CDxx-CMDOUT9	13 characters string	User name for Output 9, to be set from CAP tool or from SMS
CDxx-CMDOUT10	13 characters string	User name for Output 10, to be set from CAP tool or from SMS
CDxx-CMDOUT11	13 characters string	User name for Output 11, to be set from CAP tool or from SMS
CDxx-CMDOUT12	13 characters string	User name for Output 12, to be set from CAP tool or from SMS
CDxx-CMDOUT13	13 characters string	User name for Output 13, to be set from CAP tool or from SMS
CDxx-CMDOUT14	13 characters string	User name for Output 14, to be set from CAP tool or from SMS
CDxx-CMDOUT15	13 characters string	User name for Output 15, to be set from CAP tool or from SMS
CDxx-CMDOUT16	13 characters string	User name for Output 16, to be set from CAP tool or from SMS
CDxx-MODE	0=Off, 1=Steady, 2=Pulse	Output mode common for the command block, to be set from CAP tool or from SMS

Table 58: Setting table for Multiple Command function No. xx

Parameter:	Setting range:	Description:
CMxx-CMDOUT	13 characters string	Common user name for the outputs in the multiple command block, to be set from CAP tool
CMxx-MODE	0=Off, 1=Steady, 2=Pulse	Output mode common for the command block, to be set from CAP tool
CMxx-INTERVAL	0-60 s	Time interval for supervision of received data

Protection functions

24 Frequency measurement function (FRME)

24.1 Summary of application

The frequency measurement function FRME is used to measure the power system fundamental frequency. The frequency is given in Hertz (Hz).

The measured frequency can be read directly on the local display, placed on the front side of RET 521, or via the Station Monitoring System (SMS). Format of the display is DD.DDD Hz, e.g. 49.999 Hz.

The output F of the FRME function block in CAP tool which contains the value of frequency, should be connected to corresponding input F of the Overexcitation function block (OVEX) or Frequency protection function (FRF), if they are used.

FRME function must be used whenever an extended frequency range is required of RET 521. This means that FRME must be applied and connected in CAP tool. In order to obtain an extended frequency range the output F of the FRME function block does not need to be connected to any other function block, for instance when OVEX is not applied.

The extended operative frequency range for 50 Hz configuration is from 33 Hz to 61 Hz and for 60 Hz configuration from 39 Hz to 73 Hz.

When underreaching the low frequency limit or when measuring voltage is too low, an error is generated (ERROR is set on FRME function block output). When overreaching the high frequency limit, all protection and control functions can be blocked by using the FRME ERROR signal. Inside the frequency range of a selected configuration, all protection and control functions operates as normal.

Within the extended nominal frequency range, that is between 0.7 * fr - 1.2 * fr, the maximum error in estimation of a.c. currents and a.c. voltages is less than 2% of their respective true values. The accuracy of frequency measurement within this range is better than ±0.002 Hz, i.e. better than ±2 mHz.

The frequency range where FRME function itself performs, that is, where it measures the power system fundamental frequency, is further extended on both sides of the operative range by approximately 10 Hz and is thus for 50 Hz power system from approximately 23 Hz to approximately 70 Hz, and for 60 Hz system from 29 Hz to 83 Hz.

To be able to apply FRME, voltages must be available to RET 521. If three phase-to-earth voltages are connected to RET 521, then FRME type G3U should be applied. If only one phase-to-phase voltage is available, then FRME type SU should be applied. Types G3U or SU are chosen by means of the Function Selector in CAP configuration tool.

Stability of FRME function algorithm is very important, since the measured frequency is used to determine the window length of the adaptive Fourier filter. It is therefore recommended to use FRME type G3U whenever possible. If FRME type SU is applied, it should use a phase-to-phase voltage, while one phase-to-earth voltage as an input to a FRME type SU is not recommended.

24.2 Summary of function

FRME measures the power system fundamental frequency. The measurement principle is based on the rotational velocity of a suitable voltage phasor in the complex plane. The voltage phasor is calculated previously by an adaptive recursive Fourier filter. Due to this “synchroscope” effect the actual power system fundamental frequency can be measured very accurately.

The FRME function measures the system frequency normally 10 times per second in 50 Hz power systems and 12 times in 60 Hz power systems. In a disturbed system, frequency is usually updated more often. The input voltage to FRME is checked within FRME for its magnitude and stability. If the voltage is too low (less than 40% rated), the measurement is stopped, and the last “healthy” value of frequency value retained for 10 seconds. If the voltage recovers within 10 seconds, the measurement is resumed. If not, the FRME is reset, and rated frequency fr is assumed. The binary output, ERROR, is set to 1 in this case.

The frequency range of FRME is for 50 Hz power system from approximately 23 Hz to approximately 70 Hz, and for 60 Hz system from 29 Hz to 83 Hz.

The frequency measurement function is represented in CAP tool as a function block called FRME. There are two types available of the FRME function block. FRME type G3U is connected to a function block called V3P, which provides the positive sequence voltage phasor that serves as an input to FRME. FRME type SU is connected to a function block named V1P, which provides the phase-to-phase voltage phasor. The type of FRME function can be selected in CAP tool, by pressing

Edit
Function Selector

when on the RET 521 (terminal) level in the project tree.

The FRME function block has two outputs: the “analog” output F supplies the value of frequency in Hz. The binary output, ERROR, is set to 1 (block) when the measured frequency is out of the extended operative frequency range (for 50 Hz version from 33 Hz to 61 Hz and for 60 Hz version from 39 Hz to 73 Hz) or when measuring voltage is too low (less than 40% rated). This signal can be used to block the protection/control functions.

The frequency measurement algorithm is practically insensitive to higher harmonics in voltages connected to RET 521. Stability of the algorithm against disturbances, such as for instance total failure of one phase-to-earth voltage, is also good. FRME type G3U (positive sequence voltage input) is superior to FRME type SU (phase-to-phase voltage input) as far as insensitivity to harmonics and stability on disturbances is concerned.

24.3 Measuring principle

The frequency measurement algorithm can only be discussed together with the concept of the adaptive Discrete Fourier Filter (DFF), because they are inherently tied together, as can be seen in Fig. 39.

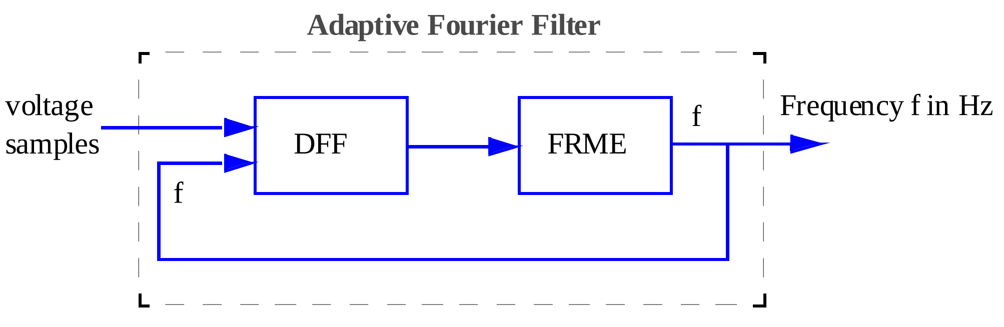


Fig. 39 The closed loop DFF - FRME - DFF

The steady-state frequency response of a nonadaptive DFF is shown in Fig. 40. With "nonadaptive" it is meant that the DFF parameter Ns is constant, Ns = 20 samples per cycle. Ns is the length of the DFF window in the number of samples, for 50 Hz systems at the same time the length of window in ms. Several important features can be observed from the gain - frequency response:

- The measured magnitude of the fundamental harmonic of an input signal is accurate only at the filter design frequency this is 50 Hz or 60 Hz. At frequencies other than rated, an error is obtained. The measured magnitude oscillates between two extreme values within the zone of uncertainty, neither of which is necessarily exact.
- All multiples of rated frequency (0 Hz, 100 Hz, 150 Hz, etc,) are totally suppressed. If the actual fundamental frequency differs from the rated, then all higher harmonics become aliasing signals.

The conclusion can be drawn, that the measurement of magnitudes of sinusoidal inputs would always be accurate under the condition that the DFF design (center) frequency, fo, follows exactly the actual input signal frequency.

A solution is to keep the DFF "sampling" or execution frequency constant, and dynamically alter the DFF window length by changing parameter Ns. By changing Ns, the DFF window is adapted in a stepwise manner to the actual power system fundamental frequency cycle. The concept of the adaptive DFF is based on:

- execution of the DFF algorithm at a rate of 1 kHz (or 1.2 kHz in 60 Hz systems),
- measurement of the actual power system fundamental frequency f in Hz,
- adaptation of the DFF window to the actual power system period (1 / f).

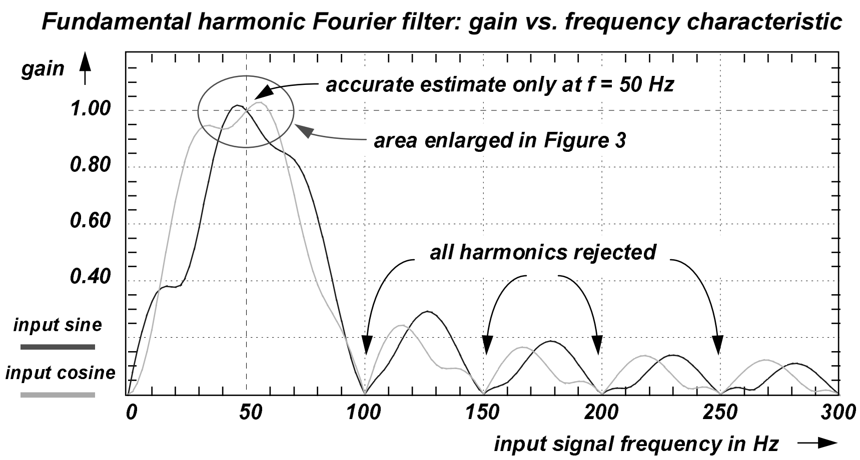


Fig. 40 Steady-state response of the fundamental frequency DFF

Area delimited by the responses for sine and cosine inputs is called the uncertainty area. The calculated values oscillate within the area of uncertainty.

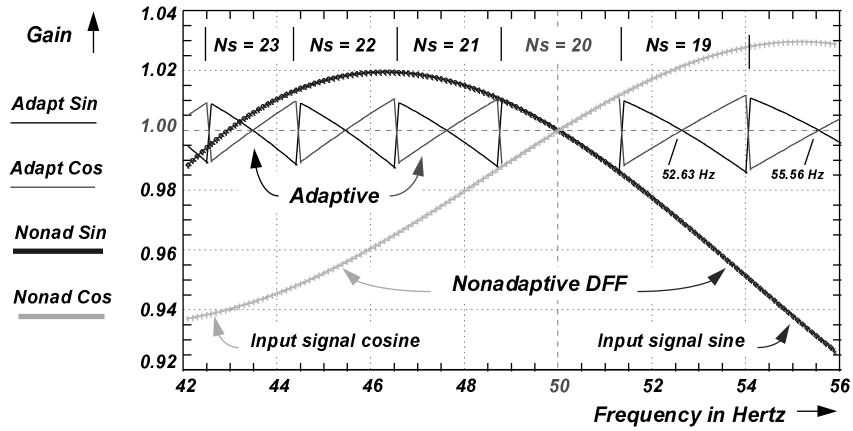


Fig. 41 Gain vs frequency response of an adaptive and nonadaptive DFF

The diagram show the gain at n_s=20 samples/cycle.

The main advantages of the fixed-sampling-frequency-adaptive-data-window approach include:

- the whole system has a fixed time reference,
- simplified hardware design,
- simplified disturbance recording function design.

Frequency estimation is an essential part of the concept of an adaptive DFF. It is based on the fact that the phasor, representing an ac input signal, e.g. voltage, will be stationary in the complex plane as long as the fundamental frequency, f, of the input signal is equal to the frequency fo which is “expected” by the filter. Parameter fo is the DFF design, or center, frequency; initially $f_o = f_r$, where f_r is the power system nominal frequency. If the actual input signal frequency, f, and the design frequency, f_o, do not match, then the phasor begins to rotate at a rate which is a rather complicated function of the difference between the actual power system frequency f, and the expected signal frequency f_o, see Fig. 42. Direction of rotation depends on the sign of Δf. If the system frequency is lower than f_o, then the phasor rotates in the negative direction, that is clockwise, and vice versa. Due to this “synchroscope” effect, the actual power system fundamental frequency can be measured.

.

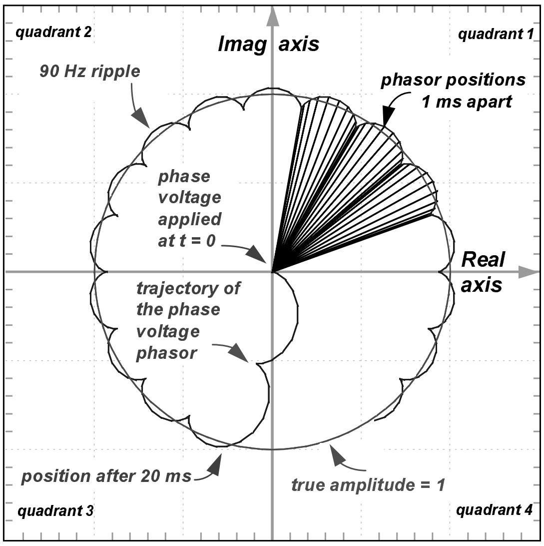


Fig. 42 Rotation of the a phase-to-earth voltage phasor

The example in Fig. 42 shows a situation when the DFF is designed for 50 Hz (Ns =20), while the input voltage signal frequency is f = 45 Hz.

Consider a DFF with Ns = 20 samples per cycle. This filter is designed for 50 Hz. Let the DFF algorithm be executed every 1 ms, that is, at a rate of 1 kHz. If the difference in frequencies is Δf = f - fo = 45 Hz - 50 Hz = -5 Hz, then the phasor rotates clockwise in the complex plane at a rate of 5 revolutions per second, as shown in Fig. 42. It will be observed from Fig. 42, where the subsequent phasor positions (1 ms apart from each other) are drawn in Quadrant 1, that, unfortunately, the actual change of angle varies from one sample to the next. Measurement of frequency, based on such a short interval of time as 1 ms would yield highly oscillatory results. A longer interval must therefore be taken, spanning, if possible, over several (rated frequency) cycles.

In this case, the average speed of rotation over a longer interval is proportional to Δf.

$$\Delta f = f - f_o$$

The following formula can be derived for the measurement of the power system fundamental frequency, which is used by FRME.

$$f(i) = f_o(N_s) \times \left(1 + \frac{\varphi(\boldsymbol{i}) - \varphi(\boldsymbol{i} - k \times N_{sr})}{2 \times \pi \times k \times f_o(N_s) / f_r} \right)$$

where:

fr	system rated frequency (50 or 60 Hz),
f(i)	actual power system frequency in Hz,
$fo(N_s)$	actual DFF design frequency in Hz,
N_s	number of samples per cycle, (16 to 31)
N_{sr}	rated number of samples per cycle (20),
φ(i)	actual position of the positive sequence voltage phasor,
$\varphi(i\text{-}k*N_{sr})$	positive sequence phasor position k * rated cycles before,

The frequency range where DFF is adaptive is only limited by the values of Nsmin and Nsmax. See Fig. 43 for the frequency range and for the DFF center, or design frequencies fo. For an adaptive DFF, the parameter Ns is a variable which is a function of the measured power system fundamental frequency f. When the power system frequency has been determined, Ns is changed, if necessary, in order to place the nearest whole number of samples into the actual power frequency cycle, and in this way adapt the filter window to the actual fundamental frequency cycle. Because Ns is a whole number (integer), the adaptation of the window can only be done in a stepwise manner.

Adaptive DFF design frequency f_o as a function of N_s

System rated frequency →	fr = 50 Hz	fr = 60 Hz
Filter execution frequency →	1000 Hz	1200 Hz
Window length in samples	DFF center frequency in Hz	
16 = Nsmin	62.500	75.000
17	58.824	70.588
18	55.555	66.667
19	52.632	63.158
20 = Nsr	50.000	60.000
21	47.619	57.143
22	45.455	54.545
23	43.478	52.147
24	41.667	50.000
25	40.000	48.000
26	38.462	46.154
27	37.037	44.444
28	35.714	42.857
29	34.482	41.379
30	33.333	40.000
31 = Nsmax	32.258	38.709
32	31.125	37.500
33	30.303	36.364

Fig. 43 DFF window length in samples Ns, and the corresponding DFF "center" frequency f_o

Adaptation of the DFF to the actual power system fundamental frequency is a closed-loop, on-line process, executed in definite intervals of time. The procedure (Swedish Patent 95038808) has the following steps (description for FRME type G3U operating on the positive sequence voltage phasor):

1 Extract the fundamental frequency component of all three phase-to-earth voltages by the DFF. Construct the positive sequence voltage phasor from the three phase-to-earth voltage phasors. (This construction is done within a V3P function block.)

2 Determine the actual power system fundamental frequency by measuring the relative rotational velocity of the (positive sequence) voltage phasor in the complex plane. Use the longest possible time interval (highest possible k) between subsequent measurements of the frequency. (This is done by FRME.)

3 Change, if necessary, the DFF by incrementing or decrementing parameter Ns (number of samples per cycle) so that the DFF becomes tuned to the center frequency fo, which is nearest at that time to the last measured power system fundamental frequency f.

The FRME algorithm is illustrated in Fig. 44. FRME function is executed 50 times in 50 Hz power systems and 60 times in 60 Hz power systems. The frequency itself is estimated normally only every 5-th execution. FRME implements an interval of k rated periods. Dependent on the stability (rate-of-change and magnitude) of the incoming voltage signal, the highest possible k is used for the frequency measurement, where k=4, or 3, or 2 or 1. Thus the interval of k * 20 ms in the case of 50 Hz or k * 16.667 ms in the case of 60 Hz power system is used between successive measurements of the power system fundamental frequency.

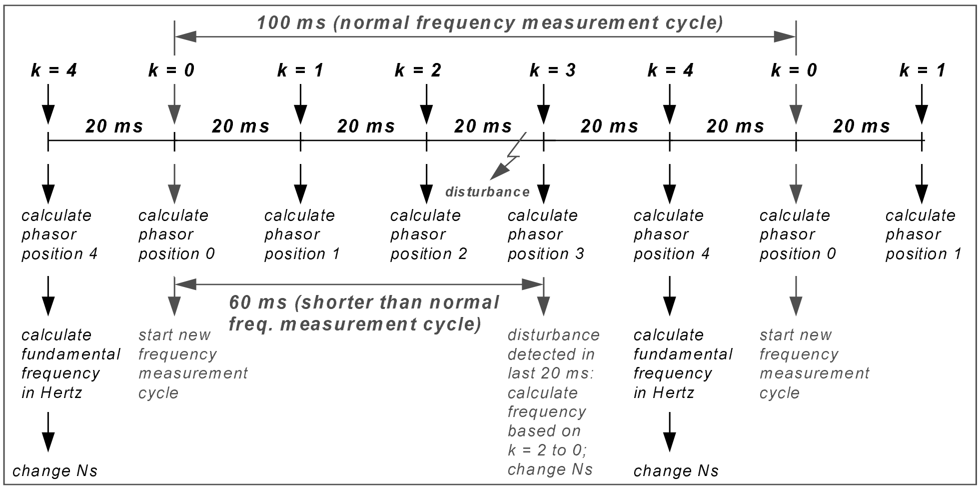


Fig. 44 The frequency measurement algorithm, shown for 50 Hz nominal frequency.

Normally, frequency is measured each 100-th ms, that is, 10 times per second. If a disturbance occurs, the interval from the last measurement can be shorter. The longest possible “healthy” interval will be taken. The interval between successive measurements of frequency is always a multiple of 20 ms, see Fig. 45.

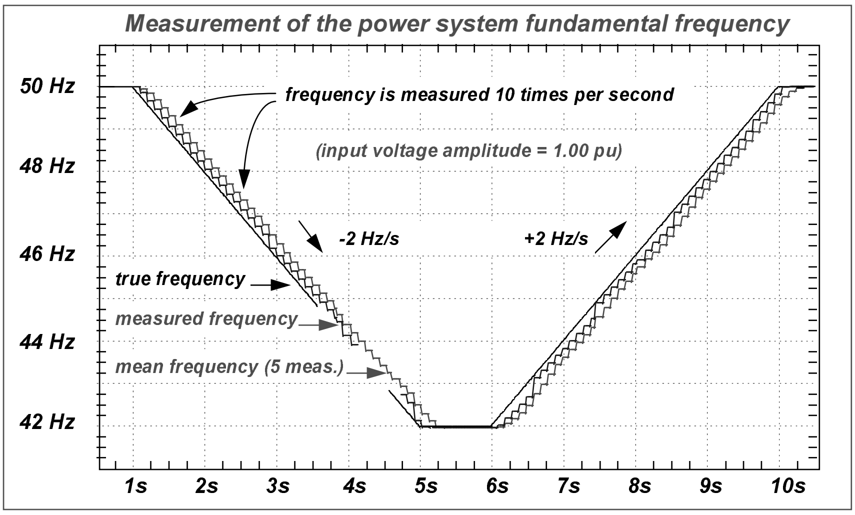
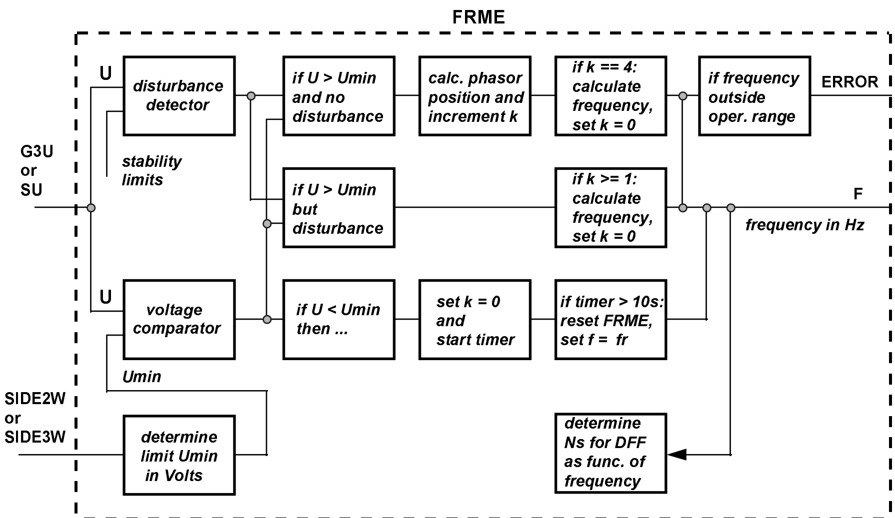


Fig. 45 Example of the measurement of frequency if frequency changes with 2Hz/s.

24.4 Logic diagram



24.5 Function block

Fig. 46 2-winding power transformer, FRME function blocks. On the left, the single voltage version (Function Selector SU), on the right, the 3-phase version (Function Selector G3U)

Fig. 47 3-winding power transformer, FRME function blocks. On the left, the single voltage version (Function Selector SU), on the right, the 3-phase version (Function Selector G3U)

24.6 Input and output signals

Table 59: Input signals of the FRME function block, Function Selector SU

In:	Description	Remarks
SIDE2W or SIDE3W	Transformer side, FRME	The side of the power transformer, where the voltages are taken and used for the measurement of frequency.
SU	Single voltage, FRME	The “analog” input of the “single-voltage” type of FRME, where the input voltage signal shall be connected. This input shall be connected to an output of a V1P function block in CAP tool.

Table 60: Input signals of the FRME function block, Function Selector G3U

In:	Description	Remarks
SIDE2W or SIDE3W	Transformer side, FRME	The side of the power transformer, where the voltages are taken and used for the measurement of frequency.
G3U	Three phase voltage group, FRME	The “analog” input of the “three-voltage” type of FRME, where the input signal shall be connected. This input shall be connected to an output of a V3P function block in CAP tool.

Table 61: Output signals of the FRME function block

Out:	Description	Remarks:
ERROR	General FRME function error	Set to 1 (block) when the measured frequency is outside the extended frequency range or when measuring voltage is too low. Can be used to block protection / control functions.
F	Mean frequency, FRME	Contains the value of the measured frequency, or rated frequency (50 Hz or 60 Hz) if the power system frequency cannot be measured.

24.7 Service report values

Table 62: FRME service value

Parameter:	Range:	Step:	Description:
f	00.000 - 99.000	0.001	Power system frequency in Hz

25 Differential protection (DIFP)

25.1 Summary of application

The power transformer is one of the most important links in a power system yet, because of its relatively simple construction, it is a highly reliable piece of equipment. This reliability, however, depends upon adequate design, care in erection, proper maintenance and the provision of protective equipment. Adequate design includes proper insulation of windings, laminations, corebolts, etc. Care in erection includes care to avoid physical damage, leaving or dropping anything foreign inside the tank (tools for example), etc. Proper maintenance includes checking the oil and winding temperatures, dryness and insulation level of the oil, and analyzing any gas that may have accumulated above the oil.

The power transformer possesses a wide range of characteristics and certain special features which make complete protection difficult. These conditions must be reviewed before the detailed application of protection is considered. The choice of suitable protection is also governed by economic considerations. Although this factor is not unique to power transformers, it is brought into prominence by the wide range of transformer ratings used in transmission and distribution systems which can vary from a few kVA up to several hundred MVA. The high rating transformers should have the best protection they can get.

Protective equipment includes surge divertors, gas relays and electrical relays. The gas relay is particularly important, since it gives early warning of a slowly developing fault, permitting shutdown and repair before serious damage can occur. The overall differential protection is the most important of the electrical relays. For this protection only power transformer terminal currents are needed.

Basic conception of differential protection as applied to transformers is that Buchholz relays will detect all faults that occur under the oil, but it is possible to have a fault outside the tank, e.g. across the bushings, and although practically all such faults involve earth, it is usual for large transformers to provide high-speed biased differential protection in addition to earth fault relay. Differential protection detects short circuits outside and inside the tank and will also clear other heavy in-tank faults faster than the Buchholz (typically 25 ms against typically 100 ms). On the other hand, for small interturn faults that do not develop quickly into earth faults, the Buchholz may be the only effective protection.

Differential protection serves as the main protection of transformers against faults in the windings, at the terminal bushings, and on the connection busbars. The section of the circuit taken between the instrument current transformers on both (or three) sides of the power transformer is known as the zone of protection. All objects within zone of protection are in principle covered by the differential protection.

As the differential protection has a strictly limited zone of action (it is a unit protection) it can be designed for fast tripping, thus providing selective disconnection of only the faulty transformer, or, more exactly, all objects included in the zone of protection. A differential protection should never respond to faults beyond the zone of protection.

25.2 Summary of function

- Fast and selective protection of power transformers.
- Protects 2-winding and 3-winding power transformers.
- Multi-breaker arrangements possible.
- 24 connection groups available for 2-winding power transformers.
- 288 connection groups available for 3-winding power transformers.
- Restrained differential protection available with good sensitivity and selectivity.
- Unrestrained differential protection available to cover heavy internal faults.
- Waveform restrain criterion to detect initial, recovery and sympathetic inrush.
- Second harmonic criterion to detect initial, recovery and sympathetic inrush.
- Second harmonic criterion can be enabled all the time, or is disabled automatically after energizing of the power transformers, and re-enabled only if an external fault is detected (settable).
- Fifth harmonic criterion applied continuously to detect overexcitation condition.
- Differential current is constructed from fundamental frequency terminal currents.

- Instantaneous differential current is analysed by waveform and harmonic criteria.
- Automatic elimination of the zero sequence currents from differential currents can be disabled (settable).
- RET offers a set of 5 operate - bias characteristics.
- Each of the 5 characteristics can be shifted vertically to change base sensitivity.
- Relatively highest of all input terminal currents serves as a common bias current.
- Tap position of the On Load Tap Changer can be tracked and the power transformer turn-ratio adapted accordingly.
- OLTC position reading errors result in temporary desensitization of the differential protection.
- If an external fault has been detected, the differential protection is temporarily desensitized.
- The DIFP output logic, the so called cross-blocking logic, which is applied to separate phase trip requests and respective block signals, can be disabled (settable).

25.3 Measuring principles

25.3.1 Some definitions and requirements

1 In this document the windings of a power transformer are referred to as primary winding, secondary winding, and tertiary winding (for 3-winding power transformers) in agreement with IEC 76 standard, Swedish Standard SS 427 01 01, 1982, IEC 76-4 (1976) and British Standard BS 171, 1978.

For 2-winding power transformers the first (capital) letter denotes the connection of the high-voltage (primary) winding, the next small letter the connection of the low-voltage (secondary) winding and the figure the clock-dial reference representing the hour position of the low-voltage phasor in relation to that of the corresponding (similarly lettered) high-voltage (primary) phasor. The latter is being assumed to occupy the 0 (12 o’clock) position. In case of 3-winding power transformers, the third lower voltage winding (tertiary) is treated in the same way as the secondary winding, again using primary winding as a phase reference.

For example, if a power transformer is designated as Yy0d5, then the HV winding (Y) is referred to as primary, the MV winding (y) is referred to as secondary, and the LV winding (d) as tertiary winding.

2 In this document, in agreement with IEC 76 standard, Swedish Standard SS 427 01 01, 1982, IEC 76-4 (1976) and British Standard BS 171, 1978, power transformers with three windings, of which one winding is of appreciably smaller rating (auxiliary winding of less than approximately 10% rated, designated as +d, or +s, such as for example Yy0 +d, are referred to as 2-winding power transformers. They can be protected by a 2-winding differential scheme.

3 Power transformers can be connected to buses in such ways that the current transformers used for the differential protection will either be in series with the transformer windings, or the current transformers will be in breakers that are part of the bus, such as a ring bus or breaker-and-a-half scheme. In this document the name “T configuration” applies to the bus of two feeders (lines) which is included in the zone protected by the differential protection. The two lines may be connected in parallel, or they may constitute a meshed power network.

4 RET 521 differential protection algorithm expects all the instrument current transformers to be star (y) connected on all power transformer sides (primary, secondary, and tertiary), regardless of the protected power transformer connection group. No intermediate current transformers are generally required.

The polarity of the current transformers is arbitrary. The convention has been that the current transformers were earthed on the side of the protected power transformer, and the polarity marks located away from the power transformer. This convention has been relaxed somewhat in recent years. The terminal accepts an arbitrary configuration of current transformers, as long as current transformer polarities are correctly set.

25.3.2 Power transformer connection groups

RET 521 supports 24 2-winding power transformer connection (vector) groups.

Table 63: 2 winding power transformer vector groups

Yy00	Yy02	Yy04	Yy06	Yy08	Yy10
Yd01	Yd03	Yd05	Yd07	Yd09	Yd11
Dy01	Dy03	Dy05	Dy07	Dy09	Dy11
Dd00	Dd02	Dd04	Dd06	Dd08	Dd10

RET 521 provides 288 3-winding power transformer connection (vector) groups.

Table 64: 3 winding power transformer vector groups

Yy00y00	Yy00y02	Yy00y04	Yy00y06	Yy00y08	Yy00y10	Yy00d01	Yy00d03	Yy00d05	Yy00d07	Yy00d09	Yy00d11
Yy02y00	Yy02y02	Yy02y04	Yy02y06	Yy02y08	Yy02y10	Yy02d01	Yy02d03	Yy02d05	Yy02d07	Yy02d09	Yy02d11
Yy04y00	Yy04y02	Yy04y04	Yy04y06	Yy04y08	Yy04y10	Yy04d01	Yy04d03	Yy04d05	Yy04d07	Yy04d09	Yy04d11
Yy06y00	Yy06y02	Yy06y04	Yy06y06	Yy06y08	Yy06y10	Yy06d01	Yy06d03	Yy06d05	Yy06d07	Yy06d09	Yy06d11
Yy08y00	Yy08y02	Yy08y04	Yy00y06	Yy08y08	Yy08y10	Yy08d01	Yy08d03	Yy08d05	Yy08d07	Yy08d09	Yy08d11
Yy10y00	Yy10y02	Yy10y04	Yy10y06	Yy10y08	Yy10y10	Yy10d01	Yy10d03	Yy10d05	Yy10d07	Yy10d09	Yy10d11
Yd01y00	Yd01y02	Yd01y04	Yd01y06	Yd01y08	Yd01y10	Yd01d01	Yd01d03	Yd01d05	Yd01d07	Yd01d09	Yd01d11
Yd03y00	Yd03y02	Yd03y04	Yd03y06	Yd03y08	Yd03y10	Yd03d01	Yd03d03	Yd03d05	Yd03d07	Yd03d09	Yd03d11
Yd05y00	Yd05y02	Yd05y04	Yd05y06	Yd05y08	Yd05y10	Yd05d01	Yd05d03	Yd05d05	Yd05d07	Yd05d09	Yd05d11
Yd07y00	Yd07y02	Yd07y04	Yd07y06	Yd07y08	Yd07y10	Yd07d01	Yd07d03	Yd07d05	Yd07d07	Yd07d09	Yd07d11

Table 64: 3 winding power transformer vector groups

Yd09y00	Yd09y02	Yd09y04	Yd09y06	Yd09y08	Yd09y10	Yd09d01	Yd09d03	Yd09d05	Yd09d07	Yd09d09	Yd09d11
Yd11y00	Yd11y02	Yd11y04	Yd11y06	Yd11y08	Yd11y10	Yd11d01	Yd11d03	Yd11d05	Yd11d07	Yd11d09	Yd11d11
Dy01y01	Dy01y03	Dy01y05	Dy01y07	Dy01y09	Dy01y11	Dy01d00	Dy01d02	Dy01d04	Dy01d06	Dy01d08	Dy01d10
Dy03y01	Dy03y03	Dy03y05	Dy03y07	Dy03y09	Dy03y11	Dy03d00	Dy03d02	Dy03d04	Dy03d06	Dy03d08	Dy03d10
Dy05y01	Dy05y03	Dy05y05	Dy05y07	Dy05y09	Dy05y11	Dy05d00	Dy05d02	Dy05d04	Dy05d06	Dy05d08	Dy05d10
Dy07y01	Dy07y03	Dy07y05	Dy07y07	Dy07y09	Dy07y11	Dy07d00	Dy07d02	Dy07d04	Dy07d06	Dy07d08	Dy07d10
Dy09y01	Dy09y03	Dy09y05	Dy09y07	Dy09y09	Dy09y11	Dy09d00	Dy09d02	Dy09d04	Dy09d06	Dy09d08	Dy09d10
Dy11y01	Dy11y03	Dy11y05	Dy11y07	Dy11y09	Dy11y11	Dy11d00	Dy11d02	Dy11d04	Dy11d06	Dy11d08	Dy11d10
Dd00y01	Dd00y03	Dd00y05	Dd00y07	Dd00y09	Dd00y11	Dd00d00	Dd00d02	Dd00d04	Dd00d06	Dd00d08	Dd00d10
Dd02y01	Dd02y03	Dd02y05	Dd02y07	Dd02y09	Dd02y11	Dd02d00	Dd02d02	Dd02d04	Dd02d06	Dd02d08	Dd02d10
Dd04y01	Dd04y03	Dd04y05	Dd04y07	Dd04y09	Dd04y11	Dd04d00	Dd04d02	Dd04d04	Dd04d06	Dd04d08	Dd04d10
Dd06y01	Dd06y03	Dd06y05	Dd06y07	Dd06y09	Dd06y11	Dd06d00	Dd06d02	Dd06d04	Dd06d06	Dd06d08	Dd06d10
Dd08y01	Dd08y03	Dd08y05	Dd08y07	Dd08y09	Dd08y11	Dd08d00	Dd08d02	Dd08d04	Dd08d06	Dd08d08	Dd08d10
Dd10y01	Dd10y03	Dd10y05	Dd10y07	Dd10y09	Dd10y11	Dd10d00	Dd10d02	Dd10d04	Dd10d06	Dd10d08	Dd10d10

25.3.3 Determination of differential (operate) currents

25.3.3.1 General

In the healthy state of a loaded power transformer, currents on the opposite sides will usually differ in magnitude as well as in phase position due to power transformer turns-ratio and power transformer connection (vector) group. Power transformers introduce in most cases not only a change in magnitudes of voltages and currents, but also a change in phase angle. These effects must be considered in obtaining the correct analysis of fault conditions by differential relays.

Almost invariably the power transformer connections do not permit transformation of the zero sequence currents. To prevent unwanted operations in such cases the zero sequence currents must be eliminated from differential currents.

Numerical microprocessor-based differential algorithm compensates for both the turns-ratio and the phase shift internally. Elimination of the zero sequence currents is done internally as well, when required. No intermediate CTs are usually necessary. Intermediate CTs, as required by older relays, contributed to the distortion of the input signals and added to the cost of the protection scheme. One of the advantages of numerical differential protections is therefore that intermediate CTs are generally no longer needed.

25.3.4 Calculation of fundamental harmonic differential currents

Currents flowing on the primary, secondary (and tertiary) sides of a power transformer can be compared to each other within a numerical relay only if they are brought to a “common denominator”. The “common denominator” is in RET 521 the primary side of a power transformer (2-windings power transformers), or the side of the winding with the highest power rating. If the primary side is taken as the reference side, then the secondary side currents (and the tertiary side currents) must always be reduced (referred) to the power transformer primary side, and their respective phase shifts must be allowed for.

The differential currents, both:

- the instantaneous differential currents, as well as
- the fundamental frequency differential currents,

are calculated using expressions which were derived from the concept of equality of Ampere-turns for all windings placed on the same power transformer leg. The concept of equality of Ampere-turns holds for any number of windings around a core limb and can therefore be applied to 2-winding as well as 3-winding transformers. This method of forming the differential (operate) currents is straightforward. By applying the concept, both current magnitudes and the phase shifts are taken care of at the same time.

While the instantaneous differential currents are obtained from the instantaneous (pre-filtered) values of the input ac currents, the vectorial fundamental harmonic differential currents are calculated from the fundamental harmonic components of the input ac currents. The input currents are always the power transformer terminal (line) currents.

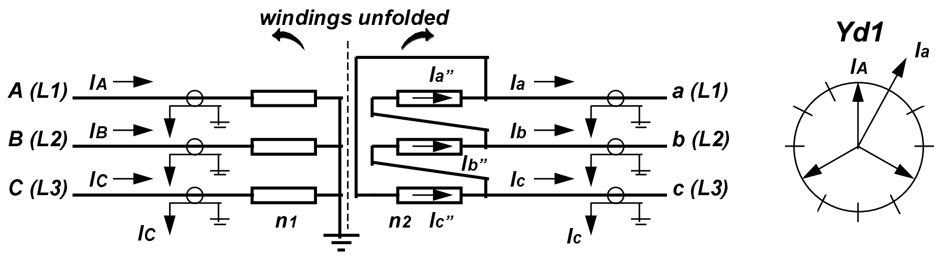
By applying the concept of Ampere-turn balance on different power transformer connection (vector) groups, the expressions which describe the respective power transformer connection groups are obtained. These differential current calculation routines are therefore as many as there are the connection groups, which is 24 for 2-winding power transformers, and 288 for 3-winding power transformers. By defining which particular connection group the protected transformer belongs to (e.g. Yd01, which is a power transformer setting, not DIFP), the proper calculation routine will applied which describes just the specified protected power transformer.

- There are always 3 differential currents, 1 per phase (a, b, c)

For example, the complex differential currents (reduced to the primary side), based on the fundamental frequency current phasors for a 2-winding power transformer, connection group Yd1 are:

$$\bar{I}dif\_A(i) = \bar{I}a(i) * (n2 / n1) - [\bar{I}A(i) - \bar{I}C(i)] \qquad \text{(phase L1)}$$
$$\bar{I}dif\_B(i) = \bar{I}b(i) * (n2 / n1) - [\bar{I}B(i) - \bar{I}A(i)] \qquad \text{(phase L2)}$$
$$\bar{I}dif\_C(i) = \bar{I}c(i) * (n2 / n1) - [\bar{I}C(i) - \bar{I}B(i)] \qquad \text{(phase L3)}$$

Designations _A, _B, and _C (and not _a, _b, _c, or _L1, _L2, _L3) are chosen in order to emphasize that the differential currents are here expressed in the power transformer primary Amperes. How such equations can be derived is shown in Fig. 48. (In a real application, the instrument current transformers' starpoints may be earthed as in Fig. 48, or in any other possible way.)



$I_a'' * n_2 = I_A * n_1$ — Equality of Ampere-turns on power transformer leg, phase a.

$I_c'' * n_2 = I_C * n_1$ — Equality of Ampere-turns on power transformer leg, phase c.

$I_a'' = I_A * (n_1 / n_2)$ — Currents which cannot be measured can be expressed

$I_c'' = I_C * (n_1 / n_2)$ — as functions of the terminal currents that are measured.

$I_a = I_a'' - I_c'' = (I_A - I_C) * (n_1 / n_2)$ — I_a'' and I_c'' which cannot be measured are now eliminated.

$I_{dif\_a} = I_a - (I_A - I_C) * (n_1 / n_2)$ — The expression for the differential current, phase a.

$I_{dif\_a} = I_a - (I_A - I_C) * (U_{r1} / sqrt(3)) / U_{r2}$ — Turns-ratio is usually obtained via rated voltages.

(98000001)

Fig. 48 Determination of differential currents for 2-winding transformer, vector group Yd1. Differential currents are in this example referred to the power transformer secondary side.

where:

$\bar{I}dif\_A(i)$ fundamental frequency differential current phasor, phase A (L1).
$\bar{I}dif\_B(i)$ fundamental frequency differential current phasor, phase B (L2).
$\bar{I}dif\_C(i)$ fundamental frequency differential current phasor, phase C (L3).

$\bar{I}A(i)$ primary side (Y), fundamental frequency phasor, phase A (L1).
$\bar{I}B(i)$ primary side (Y), fundamental frequency phasor, phase B (L2).
$\bar{I}C(i)$ primary side (Y), fundamental frequency phasor, phase C (L3).

$\bar{I}a(i)$ secondary side (d), fundamental frequency phasor, phase a (L1).
$\bar{I}b(i)$ secondary side (d), fundamental frequency phasor, phase b (L2).
$\bar{I}c(i)$ secondary side (d), fundamental frequency phasor, phase c (L3).

n1 number of turns (on one leg) of the primary side, (Y) winding.
n2 number of turns of the secondary side, (d) winding.

(i) an index denoting the most recent value, the last calculated value of a quantity. This index is omitted in the text which follows.

These three complex equations did the same job that was once done by the intermediate current transformers, that is:

1 implicitly compensate for transformer phase shift (which is 30° lagging for Yd1),

2 transform the primary, and secondary side currents to a common denominator,

3 eliminate eventual Y-side zero sequence currents from the differential currents.

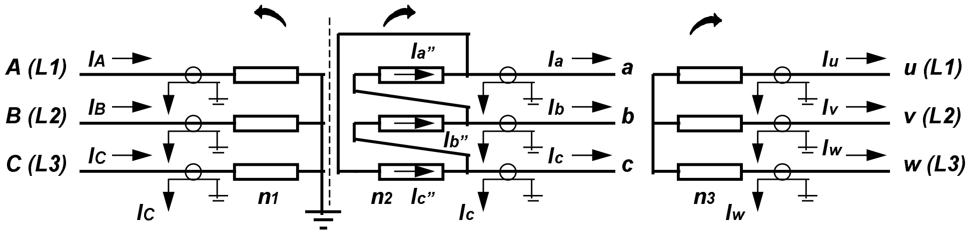
What these three equations do not do is to compensate for the zero sequence currents, which may flow through the main cts on the delta side of the power transformer if the delta winding is earthed via an earthing transformer placed within the zone protected by the differential protection. To do this, an extra procedure must be applied.

In a similar way, complex differential currents for 3-winding power transformers can be derived. An example, (where the differential currents are referred to the secondary side is as follows):

3-windings power transformer connection group Yd1y0:

$$\bar{I}dif\_a = \bar{I}a - (\bar{I}A - \bar{I}C) * (n1 / n2) + (\bar{I}u - \bar{I}w) * (n3 / n2)$$
$$\bar{I}dif\_b = \bar{I}b - (\bar{I}B - \bar{I}A) * (n1 / n2) + (\bar{I}v - \bar{I}u) * (n3 / n2)$$
$$\bar{I}dif\_c = \bar{I}c - (\bar{I}C - \bar{I}B) * (n1 / n2) + (\bar{I}w - \bar{I}v) * (n3 / n2)$$

How these expressions were derived is illustrated by way of example in Fig. 49. (In a real application, the instrument current transformers may be earthed as in Fig. 49, or in any other possible way.)



$I_a'' * n_1 + I_u * n_3 = I_A * n_1$ — *Equality of Ampere-turns on power transformer leg, phase a.*

$I_c'' * n_2 + I_w * n_3 = I_C * n_1$ — *Equality of Ampere-turns on power transformer leg, phase c.*

$I_a'' = I_A * (n_1 / n_2) - I_u * (n_3 / n_2)$

$I_c'' = I_C * (n_1 / n_2) - I_w * (n_3 / n_2)$

Currents which cannot be measured can be expressed as functions of the terminal currents that are measured. All currents are now reduced to the transf. secondary side.

$I_a = I_a'' - I_c'' = (I_A - I_C) * (n_1 / n_2) - (I_u - I_w) * (n_3 / n_2)$ — *Currents Ia” and Ic” are now eliminated.*

$I_{dif\_a} = I_a - (I_A - I_C) * (n_1 / n_2) + (I_u - I_w) * (n_3 / n_2)$ — *This is the differential current, phase a. All currents referred to the secondary.*

(98000002)

Fig. 49 Determination of differential currents for 3-winding transformer, Yd01y00. The differential currents in this example are referred to the secondary side of the power transformer.

25.3.5 Power transformer correction factors

The turns n1, n2, n3 are usually not known, and are therefore not explicitly used in the algorithms. Instead, correction factors (taking care of turns ratio, On Load Tap Changer tap position, etc), are used. A turns ratio is the ratio of the turns of 2 windings (or parts of windings) on the same power transformer leg. It is equal to the voltages on these two windings which are wound around the same power transformer leg and thus share the same magnetic flux. The “rated” correction factors can be derived from:

- power transformer connection group,
- power transformer rated voltages,
- power transformers rated powers.

The power transformer connection group is a user settable parameter. The power transformer connection group is found, together with other relevant power transformer data, on its rating plate. The power transformer connection group is not a setting of the differential protection, but is set under the protected power transformer data.

The respective power transformer correction factors, as defined above, are derived quantities which are calculated internally and automatically, immediately following any change in transformer settings. A user does not have to think about it. Correction factors are constants belonging to the differential protection.

For some examples of 2-winding transformers the complex equations for differential currents can thus be written as:2-winding power transformer, group Yd1

$\bar{I}dif\_A = \bar{I}a * CorrFactor2 - (\bar{I}A - \bar{I}C) * CorrFactor1$
$\bar{I}dif\_B = \bar{I}b * CorrFactor2 - (\bar{I}B - \bar{I}A) * CorrFactor1$
$\bar{I}dif\_C = \bar{I}c * CorrFactor2 - (\bar{I}C - \bar{I}B) * CorrFactor1$

2-windings power transformer connection group Dd0 (and Yy0):

$\bar{I}dif\_A = \bar{I}a * CorrFactor2 - \bar{I}A * CorrFactor1$
$\bar{I}dif\_B = \bar{I}b * CorrFactor2 - \bar{I}B * CorrFactor1$
$\bar{I}dif\_C = \bar{I}c * CorrFactor2 - \bar{I}C * CorrFactor1$

For 3-windings power transformers the equations can be written in a similar way.

25.3.6 Power transformers with On-Load Tap-Changer (OLTC)

If an On-Load Tap-Changer (OLTC) is used on the protected power transformer, and the tap position information is available to RET, then, dependent on the power transformer side (winding) on which the OLTC is installed, some of the above correction factors become variable.

Example for a 2-winding transformer, group Yd1with OLTC placed on the primary winding, the complex equations for differential currents can be written as,

$\bar{I}dif\_A = \bar{I}a * CorrFactor2(TapPosition) - (\bar{I}A - \bar{I}C) * CorrFactor1$
$\bar{I}dif\_B = \bar{I}b * CorrFactor2(TapPosition) - (\bar{I}B - \bar{I}A) * CorrFactor1$
$\bar{I}dif\_C = \bar{I}c * CorrFactor2(TapPosition) - (\bar{I}C - \bar{I}B) * CorrFactor1$

The following OLTC data is required in order to be able to track the CorrFactorX when the actual tap position is changed (for details, see Settings, and the DIFP function block):

1. total number of taps, NoOfTaps
2. Rated tap number, RatedTap
3. Minimum tap (tap 1) voltage, MinTapVoltage (kV)
4. Maximum tap voltage, MaxTapVoltage (kV)

RET 521 is capable of allowing for changes of the OLTC tap positions. The actual tap position can be transmitted to the terminal as a value from CNV- or MIM-module. The actual position is stored within RET as an integer number in a buffer and the differential protection (DIFP) has access to its contents. The tap position (TCPOS input on the DIFP function block) is read by the DIFP on every execution (250 times per second in 50 Hz power systems).

- Unless a position reading error signal (OLTCERR input on the DIFP function block) has been issued, then the correction factors will be adapted immediately. If an error signal is observed, the rated tap position is assumed. Further, no TRIP will be placed if differential current is below 30% of rated.

25.3.7 T configuration (Circuit-breaker-and-a-half configuration)

Fig. 50 shows a possible configuration of a power transformer, the so called breaker-and-a-half configuration, or T configuration. The secondary side current ($\bar{I}_2$ in Fig. 50 is not directly measured. This current is a vectorial sum of the 2 feeders' currents $\bar{I}_{2f1}$ and $\bar{I}_{2f1}$: $\bar{I}_2 = \bar{I}_{2f1} + \bar{I}_{2f2}$.

.

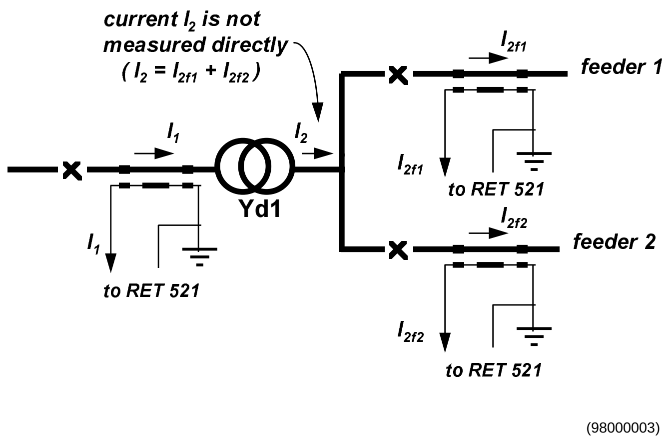


Fig. 50 Yd1 power transformer with T configuration on the secondary side.

The complex expressions for fundamental frequency differential currents can in this case be written as:

2-winding power transformer, group Yd1

$\bar{I}$dif_A = ($\bar{I}$af1 + $\bar{I}$af2) * CorrFactor2 - ($\bar{I}$A - $\bar{I}$C) * CorrFactor1
$\bar{I}$dif_B = ($\bar{I}$bf1 + $\bar{I}$bf2) * CorrFactor2 - ($\bar{I}$B - $\bar{I}$A) * CorrFactor1
$\bar{I}$dif_C = ($\bar{I}$cf 1+ $\bar{I}$cf2) * CorrFactor2 - ($\bar{I}$C - $\bar{I}$B) * CorrFactor1

where:

$\bar{I}af1$ .... feeder 1, phase a (L1) current as phasor,
$\bar{I}af2$ .... feeder 2, phase a (L1) current as phasor, etc.

Sums of the type ($\bar{I}af1 + \bar{I}af2$) in the above expressions for differential currents are made within the terminal by the C3Cx function blocks. The routine for the calculation of the differential currents is fed with the resultant sum currents ($\bar{I}a$, $\bar{I}b$, $\bar{I}c$) and the routine itself knows nothing about the T configuration.

Yet, currents flowing in both feeders are investigated separately when calculating the bias current.

25.3.8 Instantaneous differential currents

Identical (in form) sets of equations can be derived for instantaneous differential currents. It is clear that the law of equal Ampere-turns must hold for a healthy power transformer at any point of time, that is, also for instantaneous values of currents. The instantaneous differential currents are calculated in the same way as the phasor differential currents, only that the instantaneous (prefiltered) values of the respective input currents are used. There are three instantaneous differential currents, i.e. one per phase (L1, L2, L3)

Instantaneous differential currents are necessary so that they can be checked as to their harmonic content (the 2-nd and the 5-th harmonic), or their waveform can be analyzed in order to detect an eventual inrush or overexcitation. To this purpose, at least Ns (Ns is the actual window of the DFF given in samples, normally Ns = 20) most recent values (samples) of instantaneous differential currents must be stored in a circular buffer. RET 521 stores the last Nsmax = 32 values of an instantaneous differential current. There are three such circular buffers, one per phase (L1, L2, L3)

25.3.9 Differential currents due to factors other than faults

All differential currents, not caused by faults, are unwanted disturbances. Some of these false differential currents can be minimized, while other are unavoidable, and must be recognized and a proper action taken to prevent an unwanted trip.

When a power transformer differential protection is to be set up, measures must be taken to attain the best possible balance in order to reduce to a minimum the value of the unbalance current (false differential current) during normal load conditions and during occurrence of external short circuits. By having done this, the highest possible base sensitivity and stability of the differential protection will be achieved.

Still, a simple differential protection arrangement such as one based only on the above expressions for differential currents would be handicapped by difficulties due to several natural phenomena which are the cause of false differential currents. Some of these phenomena, such as the inrush and Overexcitation currents, and saturation of instrument current transformers, are the main concern in designing an efficient differential protection algorithm. The main difficulties encountered by a differential protection can be classified as:

1. currents that only flow on one side of a power transformer,
   - zero sequence currents which cannot be transformed to the other side,
   - initial-, recovery- and sympathetic inrush magnetizing currents,
   - overexcitation magnetizing currents.
2. different current transformer characteristics, loads, and operating conditions:
   - unequality of instrument current transformers on power transformer sides,
   - different relative loads on secondaries of instrument current transformers,
   - placement of current transformers in series with the transformer winding, or in circuit breakers which are part of bus, such as a breaker-and-a-half scheme.
3. errors in the protected power transformer turns-ratio(s) as a result of unknown OLTC tap position.

Measures must be taken in order to minimize the negative effects of the phenomena specified above, which might cause a false (unwanted) trip of the protected power transformer. Such measures are:

- elimination of zero sequence currents from differential currents, if relevant,
- detection of inrush magnetizing currents,
- detection of overexcitation magnetizing currents,
- reading the OLTC tap position,
- detection of external faults (causing current transformer saturation),
- calculation of an appropriate bias (restrain) current.

25.3.10 Elimination of zero-sequence currents from differential currents

To make the overall differential protection insensitive to external earth faults in situations where the zero-sequence currents can flow into the protected zone on the faulted side, but cannot be properly transformed to the other side(s) of a protected transformer, (so that they would flow through the power transformer and out into the power system), the zero-sequence currents must be eliminated from the power transformer terminal (line) currents in the expressions for differential currents, so that they cannot appear as false differential currents.

Situations when the zero sequence current cannot be properly transformed to the other side of the power transformer are very common. Power transformer connection groups of Yd or Dy type cannot transform the zero sequence current from y-side to d-side of the power transformer.

A special case is when the delta winding of a power transformer is earthed via an earthing transformer inside the zone protected by the differential protection. Then, for an external earth fault on that side, the zero sequence currents flow into the protected zone, but no correspondent zero sequence current will appear on the other side of the power transformer. See Fig. 51.

In the terminal, the automatic elimination of zero-sequence current is done numerically, if required, and no special intermediate transformers, or “zero-sequence traps” are necessary for the purpose.

The compensation can be applied to instantaneous, as well as to vectorial fundamental harmonic differential currents. This compensation is required in a vast majority of cases.

It will be observed from the expressions below that the zero sequence currents on the star (y) side eliminate each other in the expressions for differential currents of Yd or Dy type transformers. On the delta side, however, they have to be eliminated explicitly. The zero sequence current is calculated within the terminal from the sets of three terminal currents for a given power transformer side. They are then, where needed, subtracted from each terminal current in the expressions for differential currents.

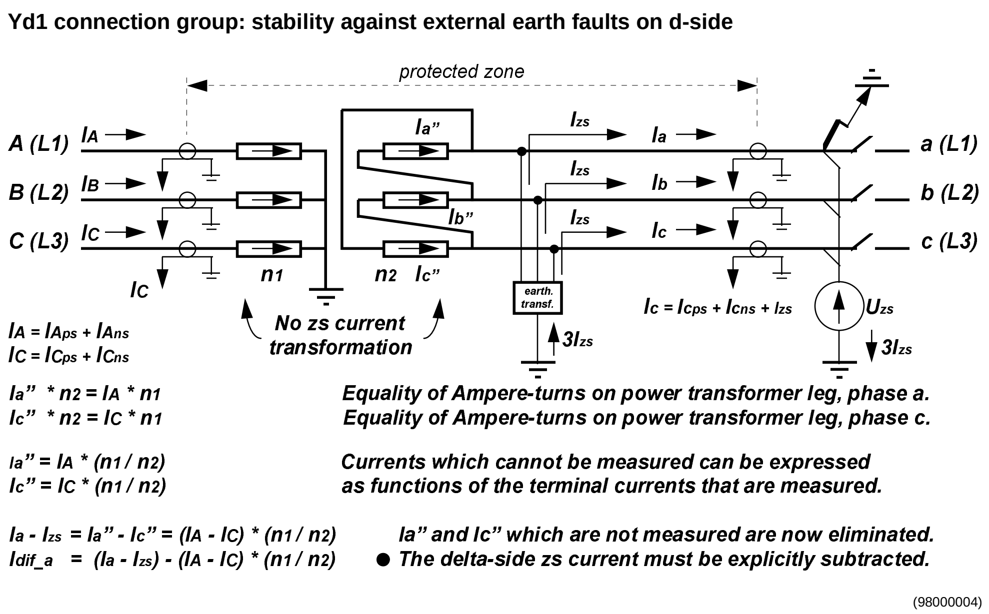


Fig. 51 Yd1 power transformer with the delta winding earthed within the zone of protection. Differential currents are referred to transformer secondary side.

It will be observed from Fig. 51 that for an external earth fault on the d-side of the Yd1 power transformer, the zero-sequence currents flow into the zone of protection, but cannot be transformed to Y-side. These currents must therefore be explicitly subtracted from d-side terminal currents $\bar{I}a$, $\bar{I}b$, and $\bar{I}c$.

As an example the equations for a 2-winding power transformer connection group Yd1 will be as follows:

$\bar{I}dif\_a = (\bar{I}a - \bar{I}zs\_2) * CorrFactor2 - (\bar{I}A - \bar{I}C) * CorrFactor1$
$\bar{I}dif\_b = (\bar{I}b - \bar{I}zs\_2) * CorrFactor2 - (\bar{I}B - \bar{I}A) * CorrFactor1$
$\bar{I}dif\_c = (\bar{I}c - \bar{I}zs\_2) * CorrFactor2 - (\bar{I}C - \bar{I}B) * CorrFactor1$

where:

$\bar{I}zs\_2$ the zero sequence current on the secondary (2), d-side of the power transformer, calculated by RET internally from 3 terminal d-side currents.

In those few, rare cases, where the zero sequence currents can be properly transformed to the power transformer other side, (e.g. Yy00 power transformer, directly earthed on both sides, and with 5-leg iron core), the zero sequence current does not need to be subtracted. RET 521 offers the setting ZSZSub, which can be set to On (default), or Off. If On, the zero sequence current is subtracted, if Off, the zero sequence current is not subtracted.

25.3.11 Detection of inrush magnetizing currents

25.3.11.1 Inrush phenomenon

Inrush is a transient condition which occurs when a power transformer is energized. It is not a fault condition, and therefore does not necessitate the operation of protection, which, on the contrary, must remain stable during the inrush transient, a requirement which is a major factor in the design of differential protection for power transformers.

The inrush magnetizing current flows into the protected zone on one power transformer side only (i.e. on the actual power source side), and will tend to operate the relay because the inrush current is seen by the differential protection as a true differential current.

When a previously unconnected power transformer is energized, the initial inrush currents flow, which may attain peak values corresponding to several times the transformer rated current, and which decay relatively slowly. The time constant of the transient is relatively long, being from perhaps 0.1 seconds for a 100 kVA transformer and up to 1.0 second for a large unit. The magnetizing current has been observed to be still changing up to 30 minutes after switching on.

When the power system voltage is reestablished after a short circuit has been cleared elsewhere in the power system, the recovery inrush currents will flow which fortunately are lower than initial inrush currents. Still, a differential relay which has been stable during a heavy external fault may misoperate due to recovery inrush when the fault is cleared. To prevent this, the recovery inrush must be recognized as well.

When a new power transformer is energized in parallel with another which was already in operation, the sympathetic inrush currents will flow in the later, which are lower than initial inrush currents. The phenomenon of sympathetic inrush is quite complex. Although inrush current phenomena associated with the energizing of one single power transformer are well understood, there are certain elements of uniqueness encountered when one transformer is suddenly energized in parallel with another which was already in operation.

Fig. 53 shows a case where a power transformer, vector group Yd1, was exposed to sympathetic inrush currents, when an identical power transformer was switched on in parallel. It will be noticed that:

1 maximum recovery inrush current can appear very late, contrary to initial inrush,

2 peaks of the sympathetic inrush current may reach the rated value or higher.

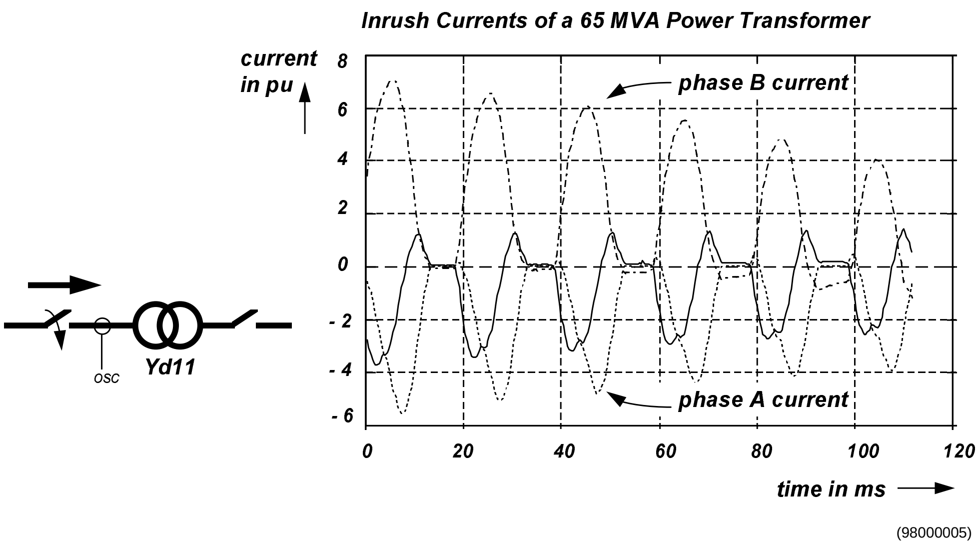


Fig. 52 Initial inrush currents of a Yd11 power transformer

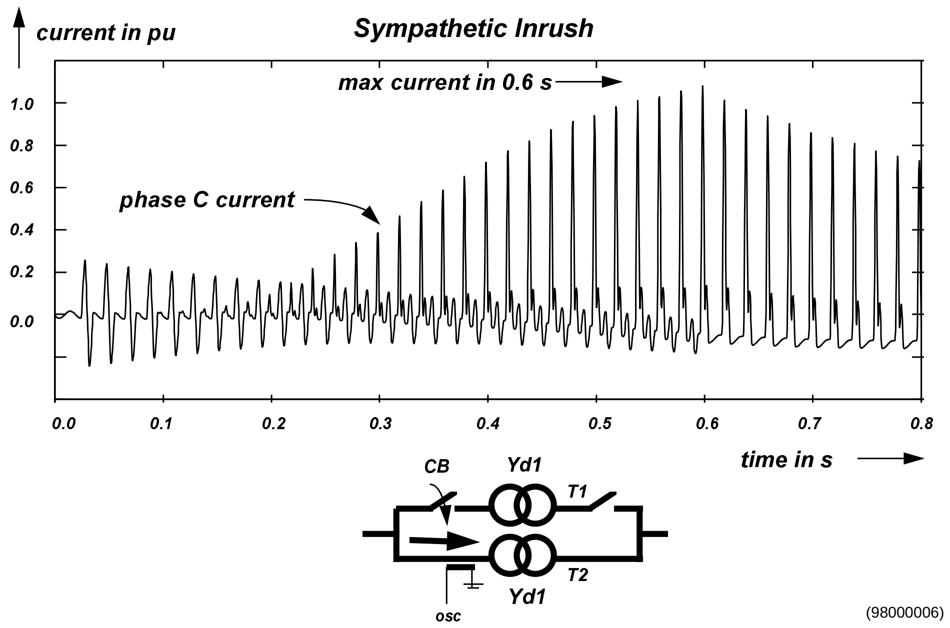


Fig. 53 An example of sympathetic inrush

The waveform of transformer magnetizing current contains a proportion of harmonics which increases as the peak flux density is raised to the saturating condition. The inrush current is an offset current with a waveform which is not symmetrical about the horizontal axis (time), but which is symmetrical, neglecting decrement, about some ordinates. Such a wave typically contains both even and odd harmonics. Typical inrush currents contain substantial amounts of second and third harmonics and diminishing amounts of higher orders. The presence of the bi-directional waveforms (phase C current in Fig. 52) substantially increases the proportion of the 2-nd harmonic, even more than 60% of the fundamental harmonic.

It will be also observed from Fig. 52 that the inrush wave is distinguished from a fault current wave by a period in each cycle during which very low magnetizing currents (normal exciting currents) flow, when the core is not in saturation. This property of the inrush current has been exploited to distinguish inrush condition from an internal fault.

25.3.12 Detection of inrush

To make a relay stable against inrush currents, measures must be taken in order to make the algoritm capable to distinguish the inrush phenomena from a fault. It is necessary to provide some forms of detection of all inrush conditions and restraint to the differential relay which depend on:

1 harmonic content of the magnetizing inrush currents and / or

2 specific pattern of the magnetizing inrush current waveform.

25.3.12.1 Detection of inrush by harmonic analysis of instantaneous differential currents

Magnitudes of harmonics in a typical magnetizing inrush current are as follows: the dc component varies between 40% to 60% of the fundamental, the 2-nd harmonic up to 70%, the 3-rd harmonic 10% to 30%. The other harmonics are progressively less. As the fault current, as seen by a differential relay, is practically clear of higher harmonics (as long as current transformers are not saturated), it seems appropriate to make use of the harmonic analysis in order to detect an inrush condition.

- As the 3-rd harmonic (which is of zero sequence) does not appear in an inrush current to a delta-type winding, the 2-nd harmonic seems to be most appropriate.
- The 2-nd harmonic content of an instantaneous differential current is compared to the fundamental harmonic of the same differential current. If the ratio is higher than the user-set limit, than an inrush condition is assumed, and a block signal issued for the affected phase by the 2-nd harmonic criterion.
- The 2-nd harmonic check in a phase is only made if a trip request (START output on the DIFP function block) has previously been placed in the same phase.

Practice has shown that although “I2/I1” approach may prevent false tripping during inrush conditions, it may sometimes be responsible for increased fault clearance times for heavy internal faults with current transformer saturation. The output current of a current transformer which is being pushed into saturation will temporarily contain the 2-nd harmonic. The proportion I2/I1 in the instantaneous differential current may temporarily exceed the user-set limit; the saturation of the current transformers has thus produced a signal which may restrain the differential relay for several cycles. On the profit side, the 2-nd harmonic restrain will give stability on heavy external faults with ct saturation.

25.3.12.2 Detection of inrush by waveform analysis of instantaneous differential currents

It has been observed from Fig. 52 that the inrush wave is distinguished from a fault wave by a period in each cycle during which very low magnetizing currents (i.e. the normal exciting currents) flow, when the core is not in saturation. This property of the inrush current can be used to distinguish this condition from an internal fault. The condition to declare inrush would be that during a power system frequency cycle, there should always be an interval of time when an instantaneous differential current is equal to the normal magnetizing current, which is close to zero (below 0.5%). This interval must be at least about 1/4 of the period, that is, about 5 ms in 50 Hz power systems.

- The waveform criterion distinguishes between inrush and internal fault, and is not confused by the 2-nd harmonic contents in the instantaneous differential current.

Unfortunately though, the picture the A/D converter sees is the one of Fig. 52. The instrument current transformers have limited capability of transforming low frequency signals, such as dc signals. This in its turn results in distorted current transformer secondary currents, and consequently distorted instantaneous differential currents. It will be observed from Fig. 52 that during the so called “low current” periods, the currents are progressively larger, and it is possible that the detection of initial inrush condition may fail if one looks for “low current” periods. The detection may not work unless special measures are taken. The solution used is as follows.

- Instead of looking for intervals with a very low instantaneous differential current, the terminal searches for intervals with low rate-of-change of an instantaneous differential current.
- The rate-of-change limit to which the rate-of-change of the instantaneous differential current is compared, is a sum of a constant, initial limit, plus a part which is proportional to the magnitude of the fundamental harmonic differential current.
- The waveform check is executed invariably and unconditionally on samples of each of the 3 instantaneous differential currents at a rate 1000 Hz in 50 Hz power system, or 1200 Hz in 60 Hz power systems. The low rate-of-change of differential current must be found at least 4 times in succession (corresponding to 4 ms in a 50 Hz power system) if the inrush condition is to be declared.

A combination of these two approaches is used in RET 521. The idea was to be able to offer an option which combines the 2-nd harmonic- and the waveform methods, so that their advantages would be made use of, while at the same time their drawbacks avoided. The two options (a DIFP setting parameter Second harmonic blocking, Conditionally/Always) are:

Conditionally

The terminal uses the 2-nd harmonic criterion to detect initial inrush, and to stabilize the differential protection against heavy external faults; the criterion is enabled when transformer is not energized and when an external fault has been detected. The algorithm is as follows:

1 employ both the 2-nd harmonic and the waveform criteria to detect initial inrush,
2 switch off the 2-nd harmonic criterion 1 minute after energizing, in order to avoid long clearance times for heavy internal faults and let the waveform criterion alone (and the 5-th harmonic) take care of the sympathetic inrush and recovery inrush,
3 switch on the 2-nd harmonic criterion for 6 seconds when a heavy external fault has been detected in order to increase stability against external faults.

Always

This option is like the usual 2-nd harmonic restrain. The 2-nd harmonic criterion is active all the time. In addition to the 2-nd harmonic criterion, the waveform criterion works in parallel.

In normal service with no fault, the differential currents are very small, theoretically zero. In this case, the DIFP function block outputs WAVBLKL1, WAVBLKL2, WAVBLKL3, can be set to 1 (WAVBLKL1 = 1, etc).This does not mean that DIFP would be blocked for an internal fault. In case of an internal fault, the WAVBLKLx signals will immediately be set to 0.

25.3.13 Detection of overexcitation magnetizing currents

Overexcitation results from excessive applied voltage, possibly in combination with below-normal frequency, as with generator-transformer units. The risk is greatest for generator-transformers, although overfluxing has been known to occur for other transformers as well.

The overexcitation condition itself usually does not call for high speed tripping of the protected power transformer, but relatively high magnetizing currents, which are seen as differential currents by the differential protection, may cause a false trip of the differential protection, unless quickly detected.

Both excessive voltage and lower frequency will tend to increase transformer flux density. The main difference from inrush is that overexcitation is a symmetrical phenomenon. An overexcitation magnetizing current contains the 1-st, the 3-rd, the 5-th, the 7-th, etc, harmonics, because the waveform is symmetrical about the horizontal axis (time). If the degree of saturation is progressively increased, not only will the harmonic content increase as a whole, but relative proportion of the fifth harmonic will increase and eventually overtake and exceed the 3-rd harmonic.

Overexcitation currents will often be superposed to normal load currents (i.e. through currents); consequently, the instantaneous differential currents must be analyzed, as they will include the overexcitation currents only.

As the 3-rd harmonic currents cannot possibly flow into a delta-type winding, the 5-th harmonic is the lowest harmonic which can serve as a criterion for overexcitation. The overexcitation on the delta side will produce exciting currents that contain a large fundamental frequency (50 or 60 Hz) component with little odd harmonics. In this instance, the 5-th harmonic limit must be set to a relatively low value.

The waveform of the excess exciting current is not present for the full period of cycle, occurring around the normal current peaks. As a consequence, there is a low-current gap in each cycle in the instantaneous differential currents. Consequently, the overexcitation condition can be detected by the waveform criterion as well.

No process is started to in order to detect inrush /overexcitation conditions by a harmonic criterion, unless at least 1 (of 3 possible) trip request (START output on the DIFP function block set to 1) has been placed by differential protection algorithm.

If a trip request has been issued by a phase, then the 2-nd harmonic is extracted by Fourier filters from that phase’s instantaneous differential current. The waveform criterion is active all the time, independent of any trip requests.

25.3.14 Determination of bias current

The bias current is supposed to show how high are the currents flowing into (or through) the zone protected by the differential protection, in order to get a measure of how difficult the conditions are under which the instrument current transformers, and the protected power transformer are operating. More difficult conditions mean generally less reliable information about the currents. Less reliable information can result in false differential currents, which are then compensated by a suitable shape of the operate - bias characteristic. In general, higher bias current requires greater differential current in order to trip the protected power transformer.

It has been found that the relatively highest power transformer current, as seen by the terminal, is the best measure of the conditions under which both the instrument current transformers as well as the protected power transformer are operating at any point of time. This bias quantity gives a good stability against an unwanted operation of the differential protection.

- The differential protection has only one bias current, common to all 3 differential currents.

The RET 521 differential protection algorithm determines the common bias as the highest of all separate currents which have first been referred to the reference side of the power transformer.

In the case of 2-winding power transformers, the reference side is always the primary side. In the case of 3-winding power transformers, the reference side is the side of the winding with the highest power rating. If a 3-winding power transformer has ratings 100 MVA / 50 MVA / 50 MVA, then the HV primary side with 100 MVA rating is taken as the reference side.

25.3.15 Determination of bias current in breaker-and-a-half schemes

When the current transformers are part of the bus scheme, such as in the breaker-and-a-half scheme (T configuration) of Fig. 50, then the fault currents are not limited by the power transformer impedance. Relatively very high primary currents through current transformers may be expected. Any deficiency of current output caused by saturation of one current transformer that is not matched by a similar deficiency of another will cause a false differential current to appear. In an attempt to counteract this:

- currents of both feeders on the T side are input separately to the terminal, and processed independently in order to determine the bias current.

In order to determine the bias current in case of a T configuration, all the separate currents flowing on the T-side are compared to the primary rating (in Amperes) of their respective current transformers. These relative currents are then referred to the reference side of the differential protection scheme.

In addition to that, the resultant currents into the protected power transformer, which are not measured directly but calculated, are compared to the transformer rated current of the side with T, and then referred to the reference side. The rest of the procedure is the same as in protection schemes without breaker-and-a-half scheme. An exception to the above rule is when the primary rating of a current transformer is less than the rated current of the protected power transformer on the side with T configuration. In this case, the T feeder currents are compared to the rated current of the power transformer of the side with T configuration, and not to the rating of the primary winding of the respective current transformer.

25.3.16 Restrained differential protection: operate - bias characteristics

To make differential relays as sensitive and as stable as possible, differential relays have been developed with bias (restraint) actuated by the input and output currents. Two points to be considered in choosing an operate-bias characteristic are:

1. The value of differential (operate) current required to operate under external fault conditions must be above the value of anticipated false (spill) differential current.
2. The value of the differential (operate) current under internal fault must be above the value of the current required to operate.

The usual practice for transformer protection is to set the bias characteristic to a value of at least twice the value of the expected spill current under through faults conditions. These criteria can vary considerably from application to application and are often a matter of judgement and therefore a flexible set of operate-bias characteristics is advantageous. Fig. 54 shows the set of 5 operate-bias characteristics that are available.

Table 65: Data sheet of operate - bias characteristics.

Characteristic number	First slope in %	Second slope in %	Base sensitivity in %	Default base sensitivity in %
1	15	50	10 - 50	10
2	20	50	10 - 50	20
3	30	50	10 - 50	30
4	40	50	10 - 50	40
5	49	50	10 - 50	50

Table 65: supplies the parameters for the 5 operate-bias characteristics available. In the DIFP algorithm, each of them is represented by a set of 3 equations of a sectionized line. For additional flexibility the base sensitivity (DIFP setting Idmin) of an operate-bias characteristic can be changed in the range from 10% to 50% rated current in 1% steps. Default sensitivity means the recommended sensitivity, but any sensitivity in the range 10% - 50% is possible. If the conditions are known in more detail, a higher or a lower sensitivity can be chosen, except for characteristics 1 and 5.

Fig. 55 shows the influence of the base sensitivity Idmin on the form of the operate-bias characteristic number 3, if Idmin is changed from 10% to 50% power transformer rated current. Whatever sensitivity Idmin, the breakpoint between zone 2 and zone 3 is always at 1 per unit operate current.

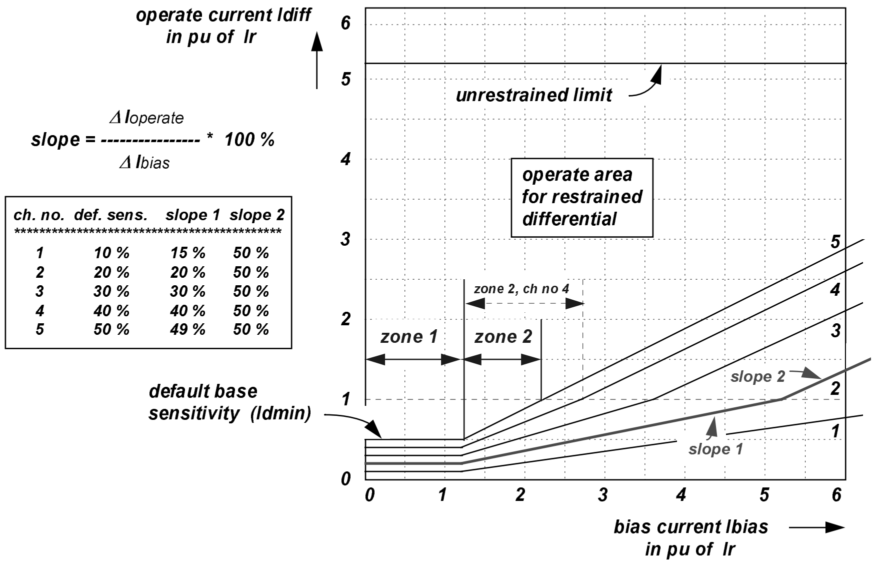


Fig. 54 Set of the 5 operate - bias characteristics

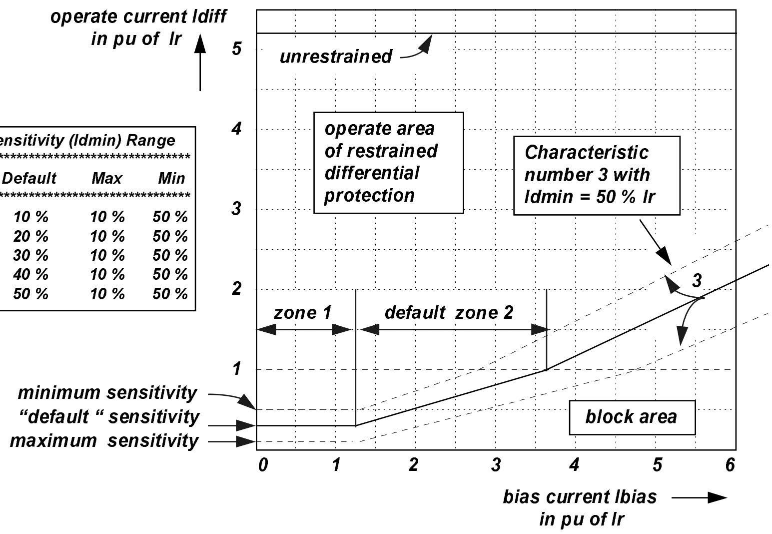


Fig. 55 Range of the base sensitivity Idmin.

25.3.17 Unrestrained (instantaneous) differential protection

The purpose of the unrestrained differential protection is to bypass the excessive restraint resulting from harmonic distortions of the current transformers' secondary currents in case of heavy internal faults. To provide for this condition, the differential protection scheme frequently includes an unrestrained "instantaneous" differential protection criterion.

If differential current is found to be higher than a certain limit, called the unrestrained limit, so that a heavy internal fault is beyond any doubt, then no restrain criteria (such as the 2-nd harmonic, the 5-th harmonic, and the waveform) is taken into consideration; a trip request is "instantaneously" issued by the overall differential protection. In fact, 2 consecutive trip requests from the unrestrained differential protection must be counted in order for a TRIP to appear on the DIFP function block output.

The unrestrained differential protection limit can be set in the range 200% to 2500% of the power transformer rated current (2 pu to 25 pu) in steps of 1% (0.01 pu).

The unrestrained differential protection limit is shown in Fig. 54, and Fig. 55. It is a horizontal line in the operate-bias current plane.

25.3.18 Stability of differential protection against heavy external faults

Stability against misoperations on external faults is particularly important when one remembers that external faults occur much more often then the faults within a power transformer itself.

Heavy external ("through-faults") with high currents with long dc constants may cause instrument current transformers to saturate quickly (in 10 ms or less). The consequence is that:

1 false differential currents appear which can be very high,

2 bias current may not increase proportionally to the true fault currents.

- As a consequence false differential currents may appear almost of the size of the bias current, and the overall differential protection might misoperate for heavy external faults unless measures were taken in order to make it stable against such faults.
- If differential protection survives without misoperating during an external fault, it could nevertheless misoperate due to the recovery inrush after the external fault has been cleared by some protection.
- If the 2-nd harmonic may be responsible for prolonged operate times at heavy internal faults with current transformer saturation, it is at the same time a good protection against misoperation on heavy external faults.

Stabilization against heavy external faults is mainly based on the 2-nd harmonic criterion. If the 2-nd harmonic is not always active (Option Conditionally) at the time an external fault has been detected, then the 2-nd harmonic is temporarily activated. Stabilization against heavy external faults thus depends on:

1 detection of an external fault,

2 temporary (6 s) activation of the 2-nd harmonic criterion,

3 temporary (6 s) desensitization of the differential protection.

The maximum sensitivity of the differential protection is temporarily set to 70% rated current (0.7 pu). No trip request from differential protection can be issued if differential current is less than 0.7 pu.

If Option Always has been set, where the 2-nd harmonic criterion is active all the time, then only the temporarily desensitization to 0.7 per unit is applied upon the detection of an external fault.

The search for an external fault is made on phase-by-phase basis. An eventual detection in any phase must come before any trip request is placed. For an internal heavy fault the trip requests come always very quickly. The trip requests appear first, and current transformer saturation may follow later. For a heavy external fault, on the other hand, the bias current will quickly become very high, while a high false differential currents will only appear if and when one or more current transformers saturate. The detection routine requires at least 4 to 6 ms before any saturation sets on to detect a fault. When a trip request is placed, the search ends.

An abnormal situation must be recognized first if the external fault detection algorithm is to start. The detection algorithm is executed only if:

1 the bias current is higher than 1.25 of the power transformer rated current (on the reference side)

2 no trip request has yet been issued by any phase.

Output logic (Cross-blocking logic)

To get a differential protection that operates when needed, and only when needed, the “trip” and “block” logical signals are optionally processed within DIFP by a common logical scheme which applies the “cross-blocking” principle. The cross-blocking logic principle is applied by the DIFP algorithm when the decision is being made whether the DIFP should issue a common trip request (i.e. set the TRIP output signal on the DIFP function block) or not. According to this principle, the DIFP only trips the protected power transformer, if all the phases which have issued trip requests (START) are free of any block signals (from the 2-nd, the 5-th, and the waveform restrain criteria). For example, if all 3 phases place a trip request, but 2 of them also have block signals (e.g. by the I2 / I1 criterion), then the differential protection will not trip the protected power transformer circuit breaker.

This feature can be optionally switched off in those rare cases where the zero-sequence current can be properly transformed by the protected power transformer. In this case any phase with a trip request set, but with no block signals set, will cause the DIFP to trip the protected power transformer.

25.3.19 Transformer differential protection: a summary of principles

The main principles of the differential protection can be summarized as follows:

1. The differential protection function is executed 250 times in 50 Hz power systems and 300 times in 60 Hz power systems per second.
2. Instantaneous differential currents, based on instantaneous values (prefiltered) of the input currents are formed at 1000 (1200) Hz. The three instantaneous differential currents are calculated to be analyzed in order to determine their 2-nd and 5-th harmonic contents and to be searched for the waveform pattern typical of inrush/overexcitation conditions.All these currents are reduced to the power transformer reference side Amperes.
3. Three fundamental harmonic differential currents, and one common bias current, are calculated from the fundamental harmonic components of the input currents, which are the power transformer terminal currents. All these currents are reduced to the power transformer reference side Amperes.
4. By default, eventual zero-sequence currents on any power transformer side are automatically subtracted from the 3 differential currents, as a measure to ensure stability for external (single-phase) earth faults. This feature can be optionally switched off in those cases where the zero-sequence current can be properly transformed by the protected power transformer.
5. One common restrain quantity, i.e. one common bias current is used. It is defined as the highest of all input currents, reduced to the power transformer reference side. A special procedure is implemented in case of “T” configurations.
6. The operate area and the block area of the “operate current - bias current” plane is delimited by the differential relay operate - bias characteristic. A set of five characteristics is available. Each of them can be shifted up or down towards more or less sensitivity when the protection settings are being made. All the operate - bias characteristics are expressed in the power transformer reference side Amperes, i.e. reduced to the protected power transformer reference side.
7. The operate area itself is divided in two parts by the unrestrained differential characteristic into “unrestrained operate” and “restrained operate” areas. The unrestrained characteristic is a horizontal line. This characteristic is as well expressed in the power transformer reference side Amperes. If a fundamental harmonic differential current is found to be higher than this limit, the differential protection operates immediately, no blocking criteria is considered.

8 If a fundamental harmonic differential current is found to be above the operate - bias characteristic, (but under the unrestrained characteristic), than a trip request is issued (START output on the DIFP function block is set), which is followed by a check to find out if any block signal exists for that phase. Block signals can be issued by the waveform criterion, or by the 2-nd harmonic block criterion (if active), or by the 5-th harmonic block criterion. The block (restrain) criteria are applied to the instantaneous differential currents in a phase-by-phase manner.

9 The 2-nd harmonic criterion can be active conditionally or permanently. It is active permanently if option Always has been chosen. If option Conditionally has been chosen, it is active when a power transformer is not energized, and for 60 s after power transformer energizing. After that, the 2-nd harmonic criterion is automatically de-activated in order to avoid its negative effect on the clearance time at heavy internal faults. It is re-activated for 6 seconds on detection of an external fault, as a means to stabilize the differential protection against misoperation on heavy external faults with ct saturation.

10 The 5-th harmonic criterion is responsible for the detection of overexcitation. It is active all the time, it is not possible to deactivate it. Its negative effect on the clearance time of heavy internal faults is less probable than that of the 2-nd harmonic.

11 The waveform criterion is active all the time, it is not possible to deactivate it. It is continuously executed at a rate 1000 (1200) Hz. It looks for low rate-of-change-of-current gaps in the instantaneous differential currents in order to detect an inrush-, or overexcitation condition. Its output signals (block signals) are available at any time, but are only taken into consideration if a phase trip request (START) has been issued in that phase.

12 The external fault detection routine is executed on a phase-by-phase basis. It starts searching for an eventual external fault whenever the condition is fulfilled that the bias current is higher than 125% of the power transformer rated current, while no trip requests have yet been placed. The criterion is based on an assumption that cts will not saturate faster than in about 4 ms to 6 ms, which means that for a heavy external fault, the differential currents will be comparatively low for at least 4 ms to 6 ms, while at the same time, the bias current will be high. If an external heavy fault is detected, the 2-nd harmonic criterion is activated (if restrain option Conditionally is set) and the DIFP sensitivity is changed to 70% for 6 s.

13 The “cross-blocking” principle is applied by the DIFP algorithm when the decision is being made whether the DIFP should issue a common trip request (i.e. set the TRIP output signal on the DIFP function block) or not. To get a differential protection that operates when needed, and only when needed, the “trip” and “block” logical signals are processed within DIFP by a common logical scheme which applies the “cross-blocking” principle. According to this principle, the DIFP only trips the protected power transformer, if all the phases which have issued trip requests (START) are free of any block signals (from the 2-nd, the 5-th, and the waveform restrain criteria). This output logic scheme can be optionally switched off.

14 In the case of the unrestrained differential protection, the common trip request signal must be confirmed for at least 2 times in succession to result in TRIP output of the DIFP function block. In the case of the restrained differential protection, only 1 common trip request is sufficient to set the TRIP output to 1, that is to switch off the protected power transformer.

25.4 Logic diagram

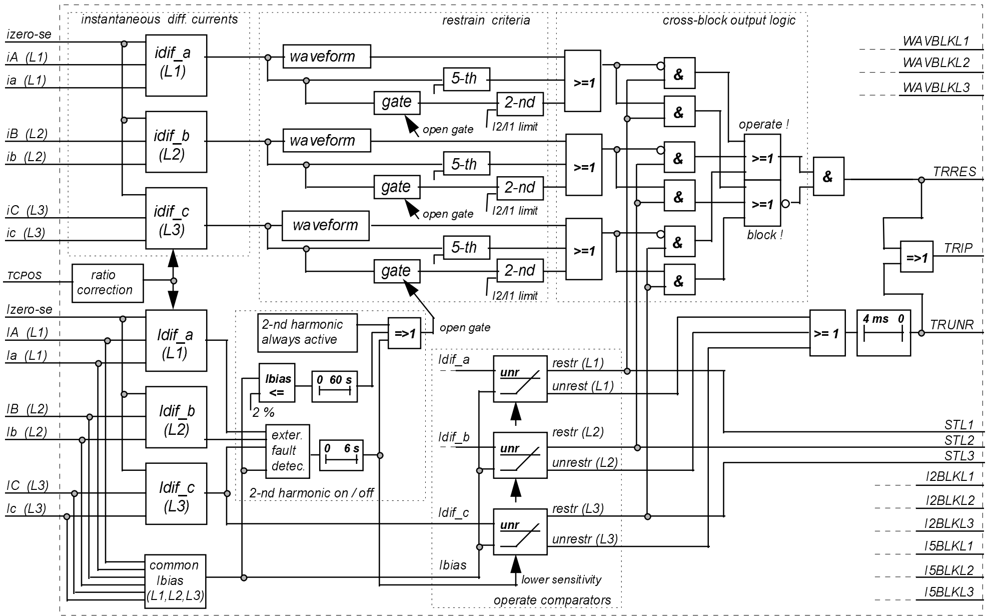


Fig. 56 Simplified DIFP logic diagram for a 2-winding power transformer.

Some simplifications were necessary when drawing the DIFP logic diagram. The major simplifications are:

1 The restrain criteria (waveform, 2-nd harmonic, 5-th harmonic) are of equal importance. If, for example, the waveform criterion places a block signal, then the 2-nd and the 5-th harmonic criteria are not executed. If the waveform criterion does not issue a block signal, then the 2-nd harmonic criterion is executed. If the 2-nd harmonic criterion places a block signal, then the 5-th harmonic criterion is bypassed, etc.

2 The limits for the waveform criterion (corresponding to limits I2/I1 limit of the 2-nd harmonic criterion, or I5/I1 limit of the 5-th harmonic criterion) are not shown.

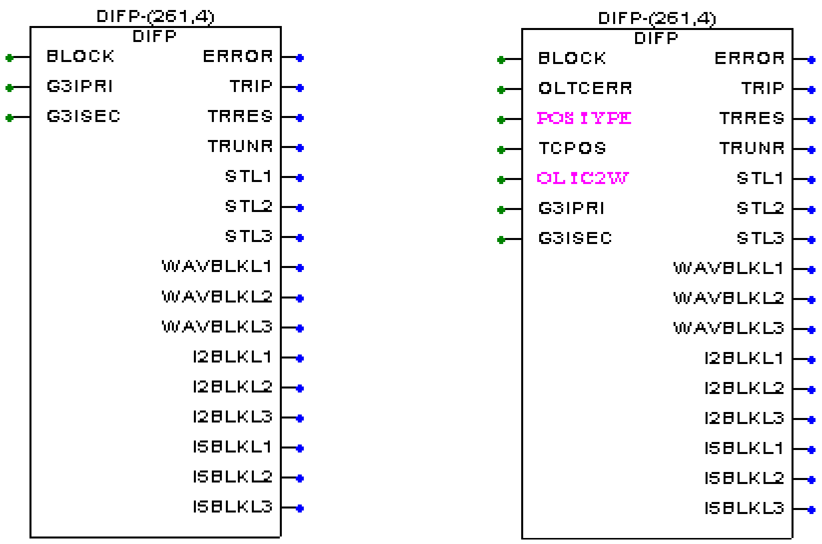
3 The 2-nd and the 5-th harmonic criteria are only executed in those of the phases (L1, L2, L3) where a trip request (shown on the DIFP function block as STL1, STL2, STL3) has been placed. The waveform criterion is executed all the time in a phase-by-phase manner.

4 The zero sequence current compensation is regularly done on all power transformer sides. This is not shown in Fig. 56, where only one (unspecified) zero-sequence current is shown.

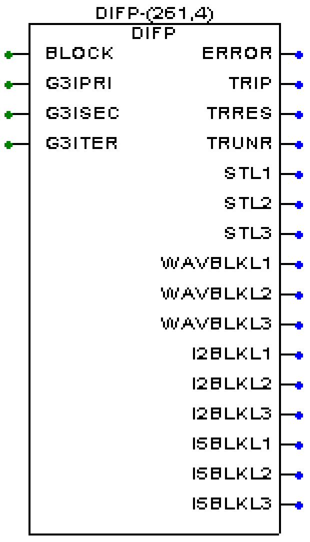
5 It is not shown that OLTC position reading error results in temporary decrease of the sensitivity of the DIFP to at least 30% of the rated current.

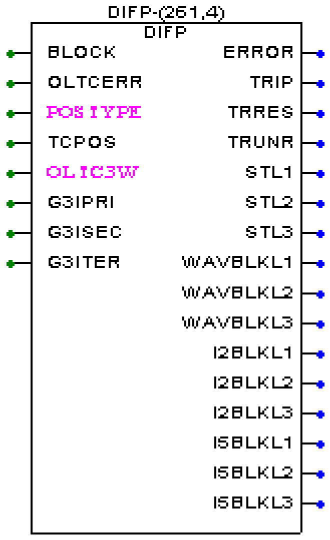
25.5 Function block

A **2-winding** power transformer DIFP function block when no On Load Tap Changer tap-position information is available (Function Selector 1 = NoOLTC, on the left side), and when On Load Tap Changer tap-position information is available (Function Selector 2 = OLTC, on the right side).



A **3-winding** power transformer DIFP function block when no On Load Tap Changer tap-position information is available (Function Selector 1 = NoOLTC, on the left side), and when On Load Tap Changer tap-position information is available (Function Selector 2 = OLTC, on the right side)





25.6 Input and output signals

Table 66: all possible DIFP block input signals (see DIFP function blocks!)

In:	Description:
DIFP:BLOCK	External block, DIFP
DIFP:OLTCERR	OLTC position reading error, DIFP
DIFP:POSTYPE	Tap changer position indication type, DIFP
DIFP:TCPOS	Tap changer position indication, DIFP
DIFP:OLTC2W	Winding where OLTC is physically located, DIFP
DIFP:OLTC3W	Winding where OLTC is physically located, DIFP
DIFP:G3IPRI	Three phase current group primary side, DIFP
DIFP:G3ISEC	Three phase current group secondary, DIFP
DIFP:G3ITER	Three phase current group tertiary side, DIFP

Table 67: DIFP function block output signals

Out:	Description:	Type	Range
DIFP:ERROR	General DIFP function error	Int	0 - 1
DIFP:TRIP	Common trip DIFP	Int	0 - 1
DIFP:TRUNR	Trip unrestrained, DIFP	Int	0 - 1
DIFP:TRRES	Trip restrained, DIFP	Int	0 - 1
DIFP:STL1	Start phase 1, DIFP	Int	0 - 1
DIFP:STL2	Start phase 2, DIFP	Int	0 - 1
DIFP:STL3	Start phase 3, DIFP	Int	0 - 1
DIFP:WAVBLKL1	Waveform block phase 1, DIFP	Int	0 - 1
DIFP:WAVBLKL2	Waveform block phase 2, DIFP	Int	0 - 1
DIFP:WAVBLKL3	Waveform block phase 3, DIFP	Int	0 - 1
DIFP:I2BLKL1	Second harmonic block phase 1, DIFP	Int	0 - 1
DIFP:I2BLKL2	Second harmonic block phase 2, DIFP	Int	0 - 1
DIFP:I2BLKL3	Second harmonic block phase 3, DIFP	Int	0 - 1
DIFP:I5BLKL1	Fifth harmonic block phase 1, DIFP	Int	0 - 1
DIFP:I5BLKL2	Fifth harmonic block phase 2, DIFP	Int	0 - 1
DIFP:I5BLKL3	Fifth harmonic block phase 3, DIFP	Int	0 - 1

25.7 Setting parameters and ranges

Table 68: Differential protection settings, their ranges and descriptions

Parameter:	Range:	Description:
Operation	0 - 1	Operation Transformer Differential Protection, Off/On
CharactNo	1 - 5	Stabilizing characteristic number
Idmin	10 - 50	Maximum sensitivity in % of Ir
Idunre	200 - 2500	Unrestrained limit in % of Ir
StabByOption	0 - 1	Second harmonic blocking, Conditionally/Always
I2/I1ratio	5 - 25	Second to first harmonic ratio in %
I5/I1ratio	10 - 50	Fifth to first harmonic ratio in %
ZSCSub	0 - 1	Operation Zero Sequence Current Subtraction, Off/On
CrossBlock	0 - 1	Operation Crossblocking, Off/On
NoOfTaps	1 - 64	Number of taps
RatedTap	1 - 64	Rated tap
MinTapVoltage	0.1 - 999.9	Voltage for minimum (tap1) tap in kV
MaxTapVoltage	0.1 - 999.9	Voltage for maximum tap in kV

25.8 Service value report

Table 69: DIFP function service report

Parameter:	Range:	Step:	Description:
Ibias	0.0 - 99999.9	0.1	Bias current in A[a]
IdiffL1	0.0 - 99999.9	0.1	Differential current, phase 1, in A[a]
IdiffL2	0.0 - 99999.9	0.1	Differential current, phase 2, in A[a]
IdiffL3	0.0 - 99999.9	0.1	Differential current, phase 3, in A[a]
TapPosition	1 - 64	1	Actual tap position

a. Referred to the power transformer primary side Amperes (2-winding power transformers), or to the Amperes of the winding with the highest power rating (3-winding power transformers).

26 Three/phase time overcurrent protection (TOC)

26.1 Summary of application

A fault external to a transformer results in an overload which can cause transformer failure if the fault is not cleared promptly. The transformer can be isolated from the fault before damage occurs by the overcurrent relays. On small transformers, overcurrent relays can also be used to protect against internal faults. On larger transformers, they provide backup protection for differential relays.

The overcurrent protection function is rather simple, but its application is limited by the rather insensitive setting and the delayed operation if coordination with other overcurrent relays is required. The overcurrent protection function should not be confused with overload protection, which directly protects the power transformer and normally make use of the relays that operate in a time related to the thermal capacity of the protected transformer. Overcurrent protection is intended to provide a discriminative protection against system faults, although with the settings adopted some measure of overload protection can be obtained. The function has no (thermal) memory and begins timing always from zero.

26.2 Summary of function

The time overcurrent protection function TOC:

- is based on the fundamental frequency component of currents flowing to, or from, the protected power transformer, or in lines connected to the transformer
- reset ratio is > 96%
- has a lowset stage and a highset stage
- the lowset stage can have either definite delay, or inverse delay
- a definite minimum delay is available for inverse delays
- the highest of the three phase currents is taken as a basis for an inverse delay
- the highset stage has always a definite delay
- both stages can be directional or nondirectional, independent of each other
- if both stages are directional, they can look in different directions
- if the directional reference voltage becomes too low, then a directional stage can be made nondirectional, or can be blocked.

26.3 Measuring principles

26.3.1 Time characteristics

There are two different delay types available in the time overcurrent protection (TOC): definite and inverse. Inverse delays can be:

- normal inverse
- very inverse
- extremely inverse
- long-time inverse

Definite delays are not dependent on the magnitude of the fault current. The definite timer in TOC will continue to measure the time as long as at least one (of three) currents is above the set limit. However, the reset ratio, equal to 96%, is applied to each separate current.

In the case of current-dependent relay, the delay is an inverse function of the magnitude of the fault current expressed as a multiple of the set current limit. The highest of the three phase currents above the set current limit serves as a basis for calculation of an inverse delay. IEC 255-4 defines inverse delay characteristics with the following law:

t_{op}	operate time
I	actual value of the measured earth fault current
I_{set}	set current limit

$$t_{op} = \frac{(k \times T_b)}{\left(\frac{I}{I_{set}}\right)^p - 1}$$

p exponent, power

k time multiplier

T_b base time

Table 70: Inverse delay curves, time multiplier k, and setting step of k

Inverse curve	T_b (s)	p	k	k - step
normal	0.14	0.02	0.05 - 1,1	0.01
very inverse	13.5	1	0.05 - 1,1	0.01
extremely	80	2	0.05 - 1,1	0.01
longtime	120	1	0.05 - 1,1	0.01

Normal Inverse curves

Fig. 57 illustrates the Normal Inverse curves which are defined by the expression:

$$t_{op} = \frac{(k \times 0.14)}{\left(\frac{I}{I_{set}}\right)^{0.02} - 1}$$

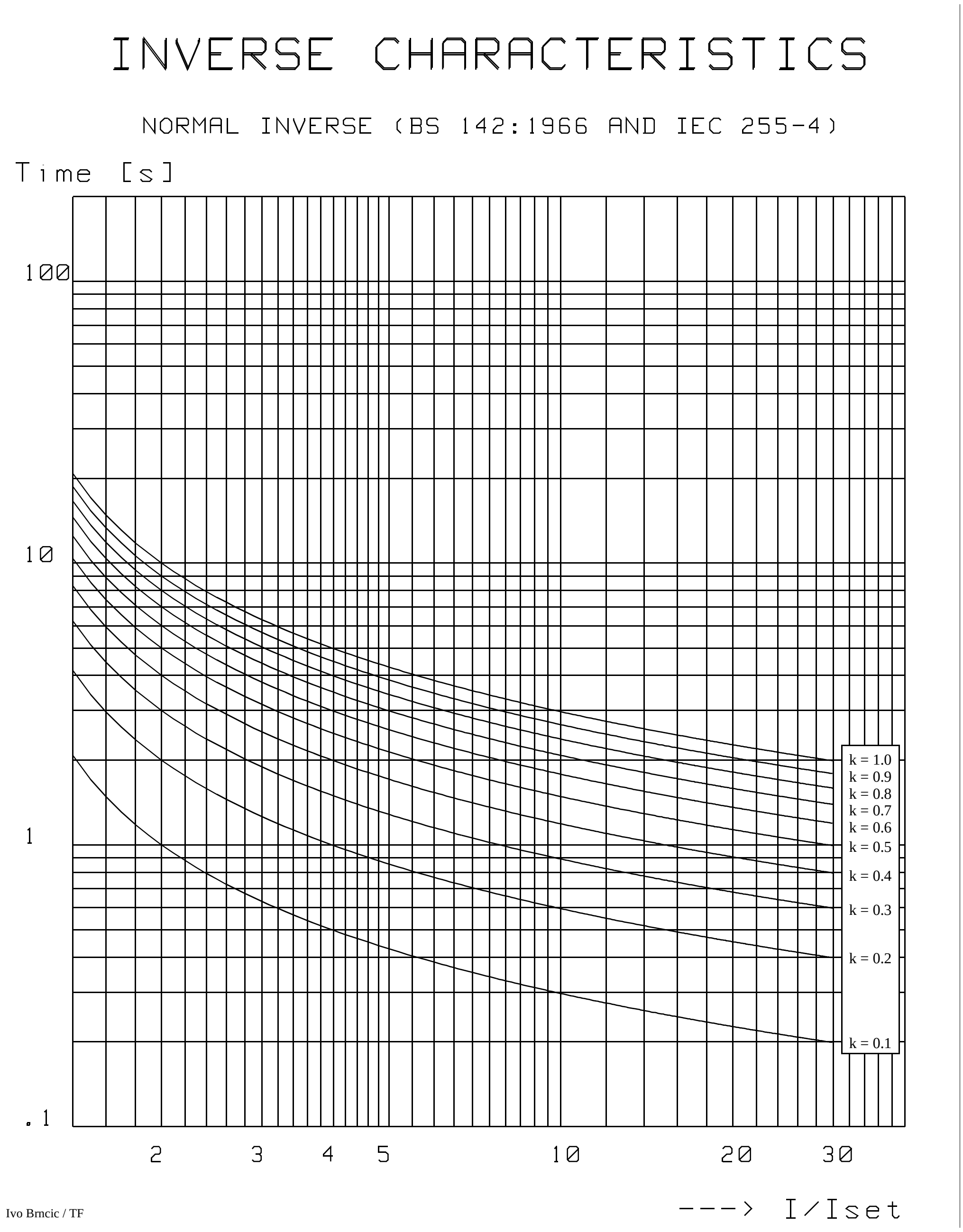
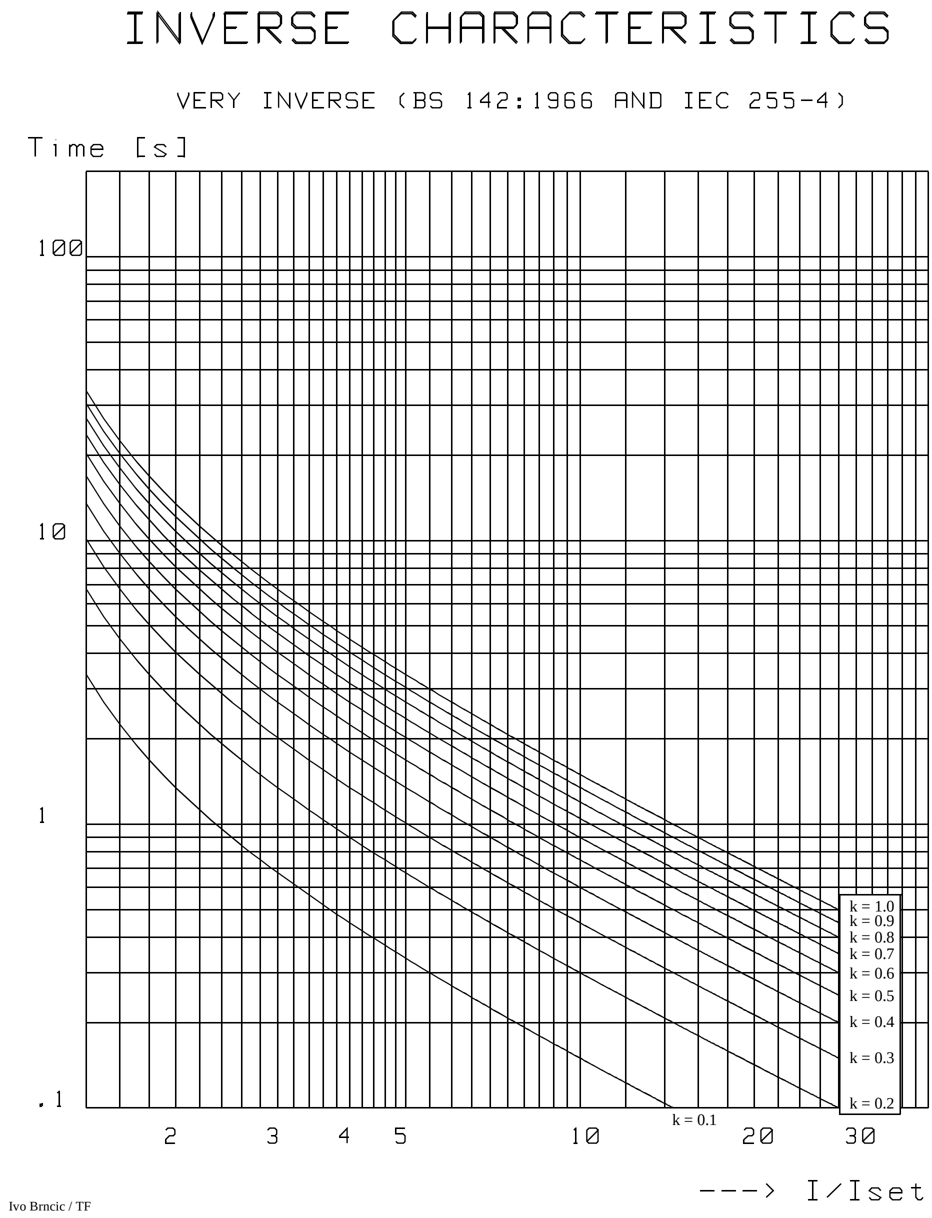


Fig. 57 Normal Inverse curves

Very Inverse curves

Fig. 58 shows the very inverse curves, defined by:



$$t_{op} = \frac{(k \times 13.5)}{\left(\frac{I}{I_{set}}\right) - 1}$$

Fig. 58 Very Inverse curves

Extremely Inverse characteristics

Fig. 59 shows the extremely inverse curves, defined by:

$$t_{op} = \frac{(k \times 80)}{\left(\frac{I}{I_{set}}\right)^2 - 1}$$

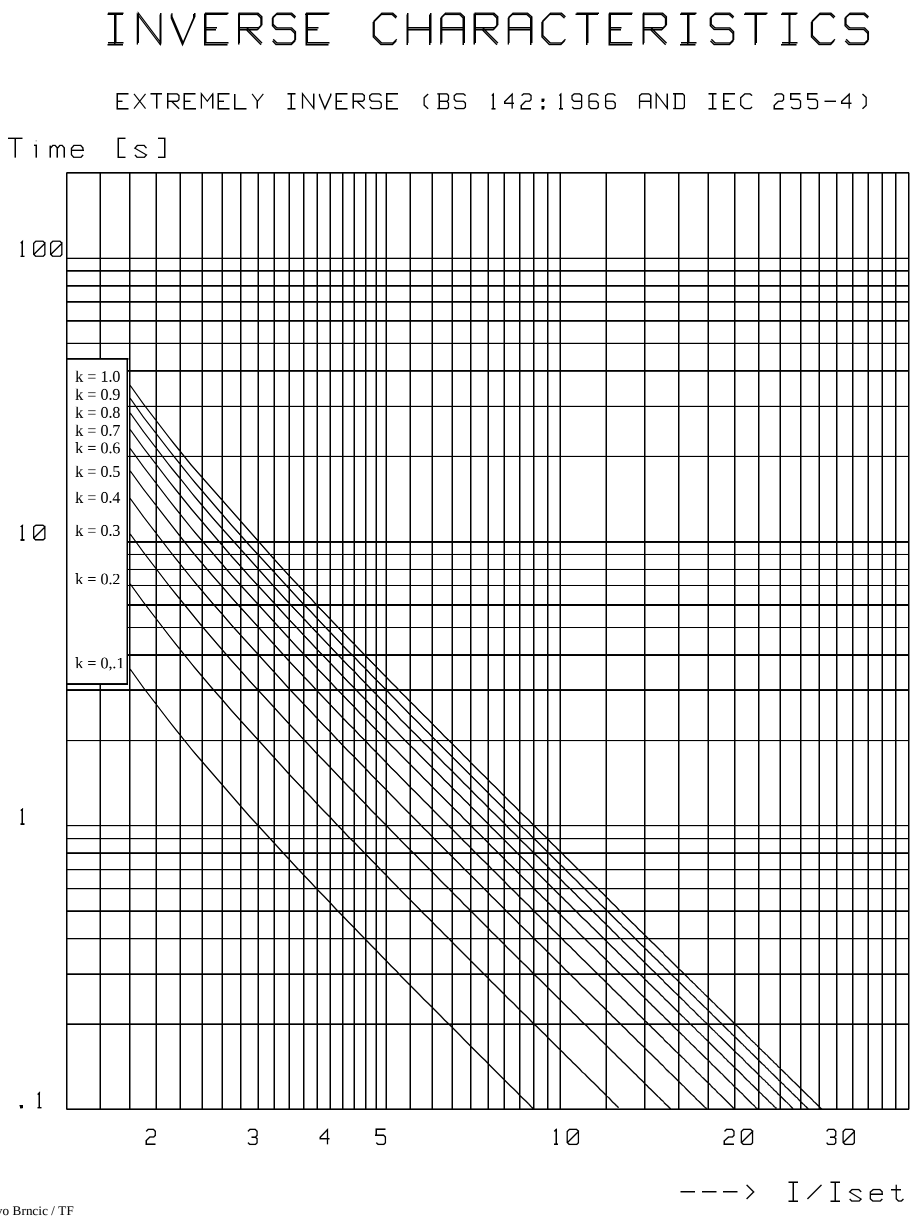


Fig. 59 Extremely Inverse curves

Long-time Inverse characteristics

Fig. 60 shows the long-time inverse curves, defined by:

$$t_{op} = \frac{k \times 120}{(I/I_{set}) - 1}$$

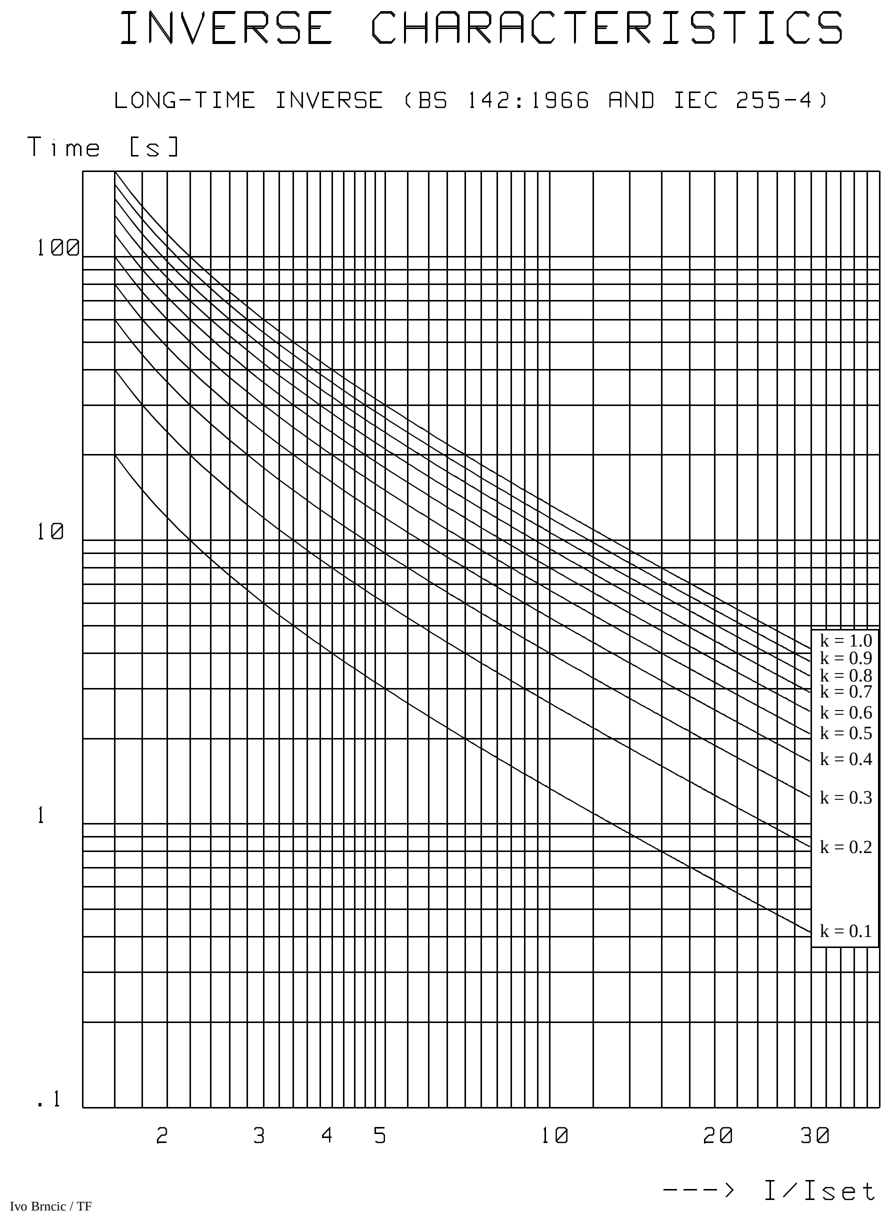


Fig. 60 Long-Time Inverse curves

26.3.2 Calculation of IEC inverse delays

Expression for the operate time t_{op}, can be re-written as:

$$t_{op} \times \left(\left(\frac{I}{I_{set}} \right)^p - 1 \right) = k \times T_b = const$$

This expression tells that the operate time t_{op} is a function of the mean value of the variable $[(I/I_{set})^p - 1]$, which in turn is a function of the variable I/I_{set}. For p = 1 this variable is equal to the relative fault current above the set value I_{set}. The operate time t_{op} will be inversely proportional to the mean value of variable $[(I/I_{set})^p - 1]$ up to the point of trip. In an integral form, the decision to trip is made when:

$$\int_0^t \left(\left(\frac{I(t)}{I_{set}} \right)^p - 1 \right) \times dt \geq k \times T_b = const$$

A numerical relay must instead make a sum:

$$\Delta t \times \sum_{j=1}^{n} \left(\left(\frac{I(j)}{I_{set}} \right)^p - 1 \right) \geq k \times T_b = const$$

where:

j = 1	a fault has been detected, for the first time it is $I / I_{set} > 1$
Δt	time interval between two successive executions of earth fault function. If the earth fault protection is executed with the execution frequency f_{ex} = 50 Hz, then Δt = 1/50 s = 20 ms.
n	an integer, the number of the overcurrent function execution intervals Δt from the inception of the fault to the point of time when the above condition for trip is fulfilled and trip command issued.
I(j)	the actual value of the fault current at point in time j.

26.3.3 Directional control of overcurrent protection

If current (or better power) may flow in either direction through the point where an overcurrent relay is placed, then a directional criterion may be applied in cases where the operation of the overcurrent protection is required for faults on one side of overcurrent relay, but not on the other.

The direction of flow of an ac current is not an absolute quantity; it can only be measured relative to some reference which itself must be an ac quantity. A suitable reference is the power system voltage.

Bearing in mind that it is the direction of the fault that is the sole requirement, the directional element is made very sensitive. Since the system voltage may fall to a low value during a short circuit, directional relay should retain its directional properties down to a low voltage, typically 1 - 2% rated value. RET’s low voltage limit is 1% rated value.

Considering the different fault types and the fact that the angle between voltage and the current for a fault can vary over a wide range, the problem of directional sensing becomes one of selecting a particular reference voltage to be associated with a particular current. The primary characteristic of the reference voltage is that it will be reasonably constant with respect to the non-faulted system conditions and to the measured current in the protected circuit.

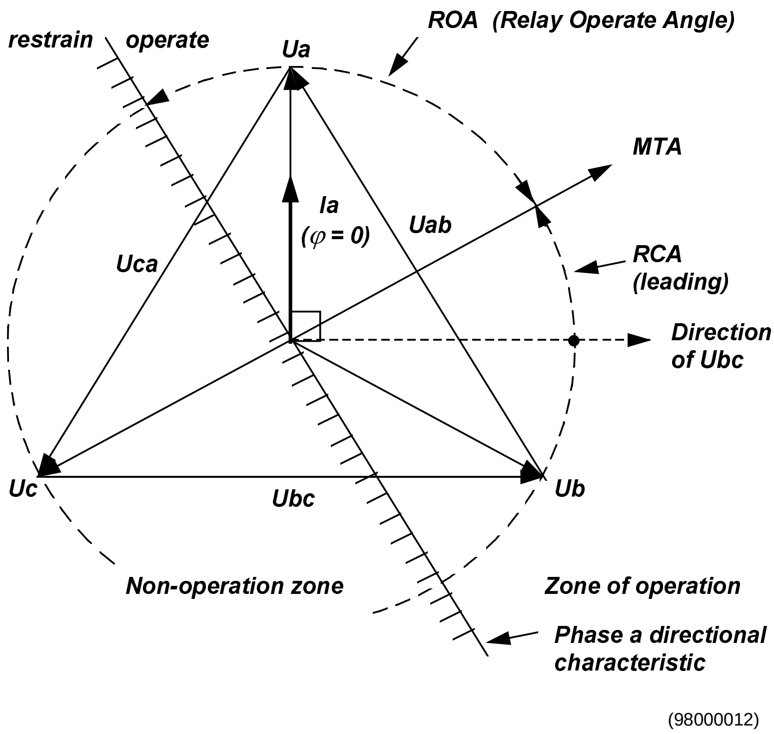


Fig. 61 Definition of 90 degrees connection.

The directional overcurrent protection utilizes the so called 90 degrees connection where the opposite phase-to-phase voltage is used as a reference voltage. For example, voltage Ubc (UL2L3) is used to polarise the phase a (IL1) current, as shown in Fig. 61.

The 90 degrees connection used traditionally 2 variants: 90 - 30 variant, and 90 - 45 variant, where 30, and 45 degrees are Relay Characteristic Angles (RCA), respectively. RET offer both variants and has the possibility to set RCA between 20-50 which suits any particular application.

The MTA (Maximum Torque Angle) is the angle by which the current applied to the relay must be displaced from the voltage applied to the relay to get the fastest response, the expected fault current position.

The RCA (Relay Characteristic Angle) is the angle by which the MTA is shifted from the directional reference (polarizing) voltage.

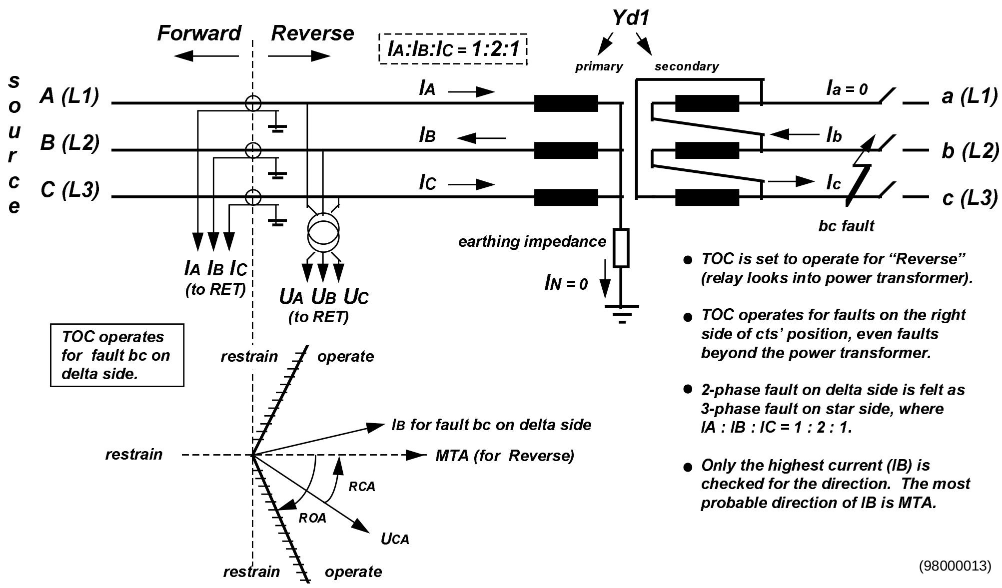


Fig. 62 If set to Reverse, TOC looks into power transformer and beyond the power transformer.

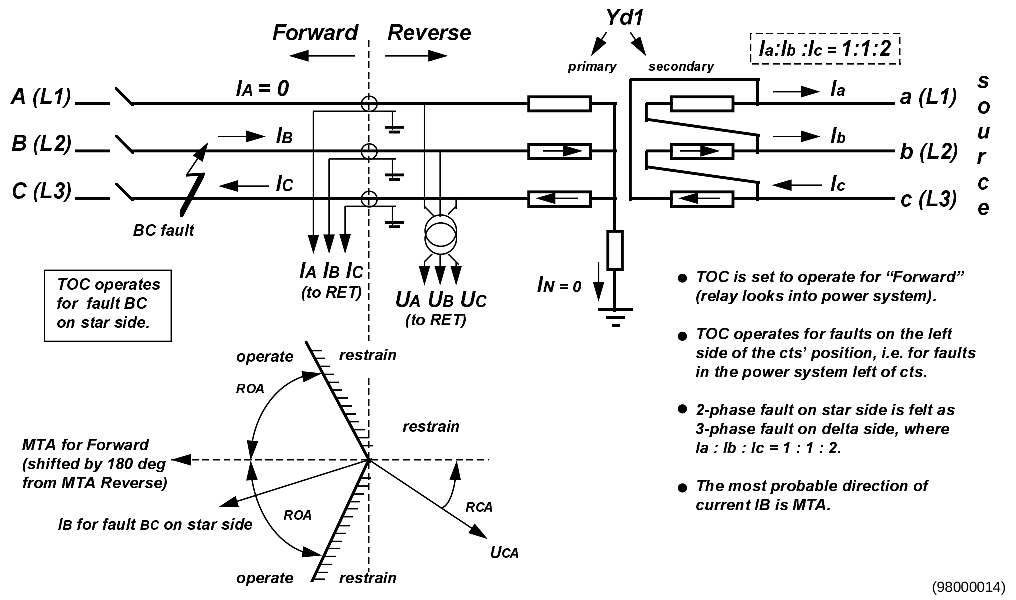


Fig. 63 If set to Forward, TOC looks from the power transformer and into the power system.

The terminal has a 180 degrees zone of operation if ROA = 90 degrees, as in Fig. 61, or a zone of operation which is reduced from 180 degrees if ROA < 90 degrees, as shown in Fig. 62 and Fig. 63. This feature provides an additional discrimination capability.

It is important to remember that only the highest of all three phase currents is checked for its direction. This the numerical equivalent of old polyphase directional relays, where 3 electromagnets operated on a single moving system. The highest current produced the highest torque, which overrode that of the other 2 phases. By doing so the other 2 (unfaulted) phases which may operate in the reverse direction are disregarded.

TOC can look into the power transformer (Reverse), or into the power system, away from the power transformer (Forward). Two examples are given by means of Fig. 62 and Fig. 63. This definition is valid for all power transformer sides.

In certain cases a relatively high current of the "operate" direction may be flowing during the normal, pre-fault conditions. In such cases and for a fault in "block" direction it would be possible to obtain a wrong answer (i.e. operate) from the directional criterion for about one cycle (20 ms). To counteract that, the answer from the directional criterion is delayed by 20 ms (for 50 Hz power systems). This is called the Current Reversal Feature. These 20 ms are added to the delay of the TOC.

If the directional reference voltage is too low to be able to positively determine the direction of a fault (i.e. determine the position of the fault with respect to TOC position), the user has 2 possibilities to choose between. The TOC may be set to become non-directional, or the TOC may be set to become blocked.

The lowset and the highset stages of the TOC are totally independent of each other with regard to directionality. They can be either directional or non-directional independent of each other. If both directional, they can look in opposite directions. If the reference voltage is too low, then they can become non-directional or blocked, independent of each other.

26.4 Logic diagram

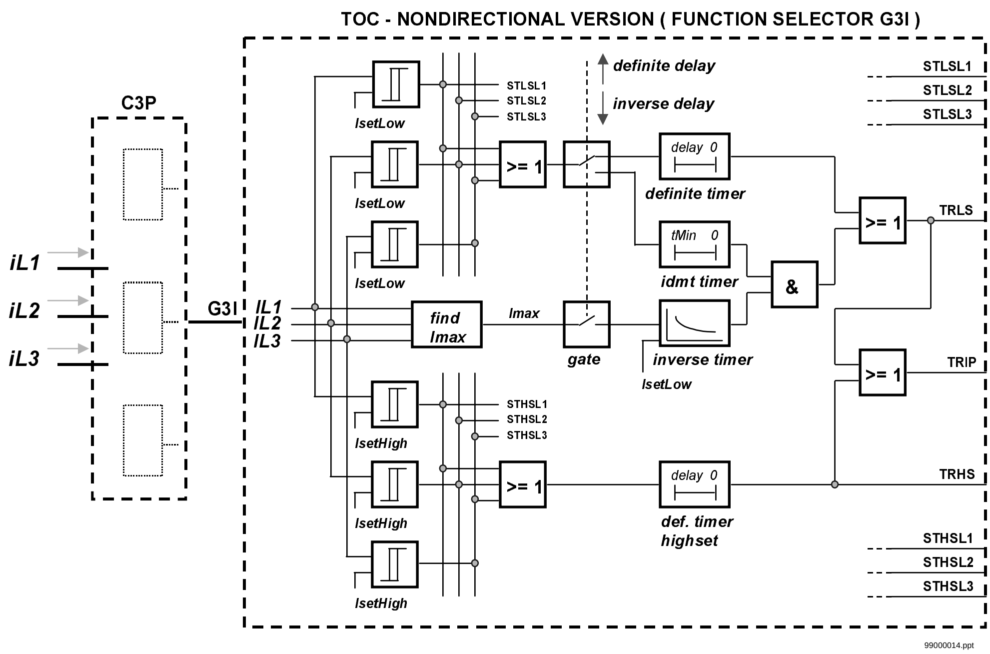


Fig. 64 Logic diagram of the nondirectional TOC.

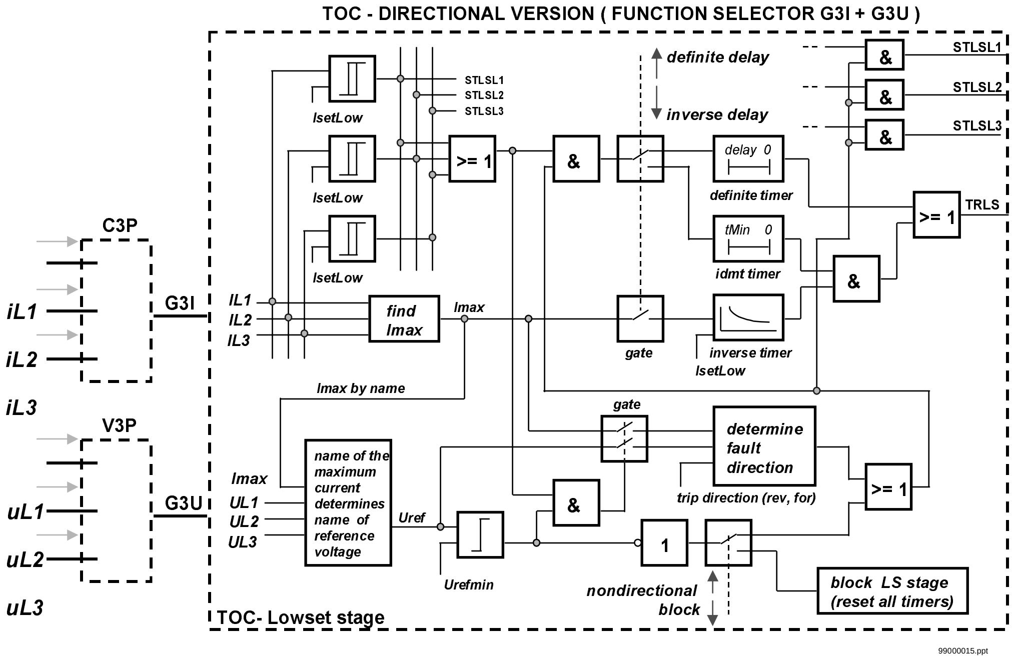
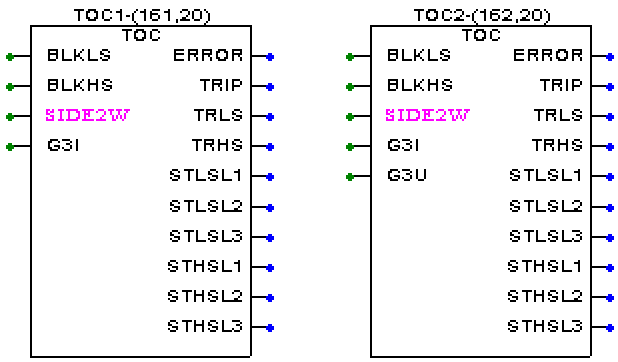


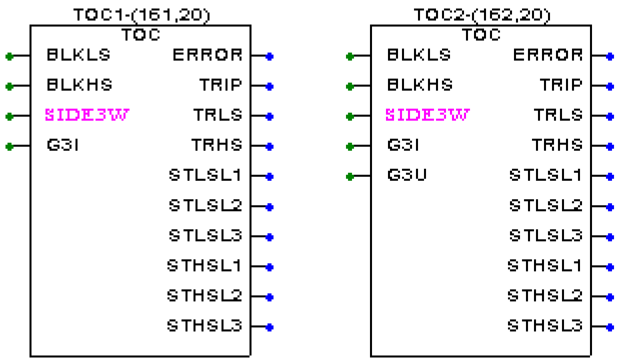
Fig. 65 Logic diagram of the directional TOC (lowset stage only)

26.5 Function block

Two-winding power transformer. There are two versions of the TOC protection: a nondirectional with function selector G3I, and a directional with the function selector G3I + G3U. The function blocks of these two versions are shown below:



Three-winding power transformer. There are two versions of the TOC protection: a nondirectional with function selector G3I, and a directional with the function selector G3I + G3U. The function blocks of these two versions are shown below:



There are altogether three instances of TOC available in RET 521.

26.6 Input and output signals

Table 71: TOC function block input signals (x = 1, 2, 3)

In:	Description:
TOCx:BLKLS	External block lowset, TOCx
TOCx:BLKHS	External block highset, TOCx
TOCx:SIDE2W	Transformer side, TOCx
TOCx:SIDE3W	Transformer side, TOCx
TOCx:G3I	Three phase current group, TOCx
TOCx:G3U	Three phase voltage group, TOCx

Table 72: TOC function block output signals (x = 1, 2, 3)

Out:	Description:	Type	Range
TOCx:ERROR	General TOCx function error	Int	0 - 1
TOCx:TRIP	Common trip TOCx	Int	0 - 1
TOCx:TRLS	Trip lowset, TOCx	Int	0 - 1
TOCx:TRHS	Trip highset, TOCx	Int	0 - 1
TOCx:STLSL1	Start lowset, phase 1, TOCx	Int	0 - 1
TOCx:STLSL2	Start lowset, phase 2, TOCx	Int	0 - 1
TOCx:STLSL3	Start lowset, phase 3, TOCx	Int	0 - 1
TOCx:STHSL1	Start highset, phase 1, TOCx	Int	0 - 1
TOCx:STHSL2	Start highset, phase 2, TOCx	Int	0 - 1
TOCx:STHSL3	Start highset, phase 3, TOCx	Int	0 - 1

26.7 Setting parameters and ranges

Table 73:

Parameter:	Range:	Description:
Operation	0=Off, 1=On	Operation Three-phase Time Overcurrent Protection, Off/On
IrUserDef	1 - 99999	Rated current for user defined side in A
IsetLow	10 - 500	Start current, lowset in % of Ir
IsetHigh	10 - 2000	Start current, highset in % of Ir
CurveType	0=DEF, 1=NI, 2=VI, 3=EI, 4=LI	Time characteristic for TOC1, DEF/NI/VI/EI/LI
tDefLow	0.00 - 300.00	Definite delay lowset in sec.
tMin	0.05 - 1.00	Minimum operating time in sec.
tDefHigh	0.00 - 300.00	Definite delay highset in sec.

Table 73:

Parameter:	Range:	Description:
k	0.05 - 1.10	Time multiplier for inverse time function
BlockLow	0=Off, 1=On	Block lowset, Off/On
BlockHigh	0=Off, 1=On	Block highset, Off/On
DirectionLow	0=NonDir, 1=Forward, 2=Reverse	Direction for trip, lowset, Non-Dir/Forward/Reverse
DirectionHigh	0=NonDir, 1=Forward, 2=Reverse	Direction for trip, highset, Non-Dir/Forward/Reverse
rca	20 - 50	Relay Characteristic Angle in deg.
roa	60 - 90	Relay Operate Angle in deg.
UActionLow	0=NonDir, 1=Block	Action low polarisation voltage, lowset, NonDir/Block
UActionHigh	0=NonDir, 1=Block	Action low polarisation voltage, highset, NonDir/Block
UrUserDef	1.0 - 999.9	Rated voltage for user defined side, in kV

26.8 Service report values

Table 74:

Parameter:	Range:	Step:	Description:
Imax	0.0 - 99999.9	0.1	Highest current in A

27 Multipurpose General Protection Function (GF)

27.1 Summary of application

A breakdown of the insulation between phase conductors or a phase conductor and earth results in a short-circuit or an earth fault. Such faults can result in large fault currents and may cause severe damage to the power system primary equipment. Depending on the magnitude and type of the fault different overcurrent protections, based on measurement of phase, ground or sequence current components, can be used to clear these faults. Additionally it is sometimes required that these overcurrent protections shall be directional and/or voltage controlled/restrained.

The over/under voltage protection is applied on power system elements, such as generators, transformers, motors and power lines in order to detect abnormal voltage conditions. Depending on the type of voltage deviation and type of power system abnormal condition different over/under voltage protections based on measurement of phase-to-ground, phase-to-phase, residual or sequence voltage components can be used to detect and operate for such incident.

Summary of function

The RET 521 terminal can be provided with up to twelve multipurpose general function protection modules. All general function protection modules are executed in RET 521 fastest internal execution cycle (i.e. five times in each fundamental power system cycle). The GF-function, with full functionality, is always connected to 3-Ph current and 3-Ph voltage input in the configuration tool, but it will always measure only one current and one voltage quantity, selected by the end user in the setting tool (i.e. maximum phase current and positive sequence voltage). Each module can be configured to any side of the transformer. It is also possible to configure any number of modules to the same side of the power transformer. Each general function module has got the following protection elements built into it:

- Two non-directional overcurrent stages working completely independently from each other. The lowset stage can be set to have either definite time delay or a user programmable inverse time delay characteristics. Therefore any inverse curve according to IEC, IEEE or ANSI standard can be obtained. Additionally the inverse time characteristic can have instantaneous or time delayed reset. The highset stage function can have definite time delay. Second harmonic blocking feature is available for both stages, however this is not possible to use with all possible choices for measured current quantities.
- Current restrained feature is available in order to restrain (i.e. prevent) non-directional overcurrent stages to start if the measured current quantity is lesser than the set percentage of the current restrain quantity. This feature can be switched off by a setting parameter.
- Voltage restrained/controlled feature is available in order to modify the pick-up level of lowset and/or highset non-directional overcurrent stage in proportion to the magnitude of the measured voltage. This feature can be switched off by a setting parameter.
- Directional criteria is available in order to prevent start of the non-directional overcurrent stages if the fault location is not in the set direction (i.e. forward/reverse)
- One overvoltage and one undervoltage stage. Both stages only have definite time delay.

All these general protection function features can be individually enabled/disabled. It is as well possible to simultaneously enable more than one feature (even all at the same time).

The general protection function can with its big setting parameter ranges be set up to operate like a TOC (Three/phase time overcurrent protection) or a TEF (Earth fault time overcurrent protection) and can therefore be used as additional or replacement of those protection functions.

27.2 Measuring principles

27.2.1 Input quantities to GF

In the CAP configuration tool a function selector setting exists for the GF-function. It can be chosen G3I or G3I+G3U. If the G3I choice is made only a current input will appear at the function block and consequently only current related functionality can be utilized. The setting parameters related to the voltage quantity are in this case of no significance. If the G3I+G3U function selector choice is made a current and a voltage input will appear at the function block and the full functionality of the GF-function can be utilized.

The multipurpose general protection function (GF) can internally be regarded as a single quantity measuring unit. E.g only one measuring current, only one restraining current and only one voltage is handled internally.
However in the CAP configuration GF is always connected to a three-phase group of currents and if the voltage related functionality is used (over/undervoltage, direction and restraining/controlling) also to a three-phase voltages group. From these three-phase currents and three-phase voltages one quantity is calculated which then is the actually further processed quantity. It is the chosen setting of the parameter CurrentInput and VoltageInput that decide which current and voltage to process further and it is the chosen setting of the parameter RestrCurr that decides which restraining current that shall be used.

The CurrentInput and VoltageInput setting parameters have actually got fourteen different possibilities and those two parameters can also be set independently of each other. The setting possibilities are any single-phase quantity (L1, L2 or L3), any phase-to-phase quantity (L1L2, L2L3 or L3L1) any symmetrical component quantity (PS, NS or 3ZS), maximum amplitude quantity within a three-phase group between either phase quantities or phase-to-phase quantities (MAX or MAX2), minimum amplitude quantity within a three-phase group between either phase quantities or phase-to-phase quantities (MIN or MIN2) and also the unbalance or difference between maximum and minimum amplitude values of phase quantities within a three-phase group (UNB).

The phase-to-phase quantities are always the vectorial subtraction of the two ingoing phase quantities.The maximum, minimum and unbalance values are calculated from the amplitudes at every execution.

The actual measured zero sequence quantities are always multiplied by a factor 3 before any comparison is made which is indicated by the name of the setting (3ZS)

If negative or zero sequence quantities from the voltage three-phase group are used as measuring quantities they are always multiplied by the factor -1 in order to get an easier direction functionality of the GF-function. This is as well indicated in the name of the setting (-NS and -3ZS)

The parameter RestrCurr deciding which current that shall be used to restrain the overcurrent functionality is limited to four possibilities (PS, NS, 3ZS and MAX) due to that other possibilities would be of quite irrelevant use.

27.2.2 Overcurrent and overvoltage/undervoltage functions

The operate values of the functions are set by a percentage setting of a base value as below. The base value is either got from the object settings (transformer rated data in the TransfData setting) or from a freely defined IrUserDef or UrUserDef setting. It is the CAP configuration SIDE2W/SIDE3W parameter setting that determines which alternative the GF will use.

$$I_{pickup} = \frac{I_{setLow}}{100} \times I_{Base} \qquad I_{pickup} = \frac{I_{setHigh}}{100} \times I_{Base}$$

$$U_{pickup} = \frac{U_{setOver}}{100} \times U_{Base} \qquad U_{pickup} = \frac{U_{setUnder}}{100} \times U_{Base}$$

The current and voltage comparisons are run at a rate of five times in each fundamental power system cycle. After a pickup a certain hysteresis is used before the reset of the function. For both steps of the overcurrent function the reset ratios are 0.96 and for the overvoltage/undervoltage functions the reset ratios are 0.99/1.01.

27.2.3 Time Characteristics

27.2.3.1 Operate time

All functions (two step of overcurrent and overvoltage/undervoltage) have got a possibility to use a settable definite delay timer before giving a trip output.

The lowset step of the overcurrent function has alternatively a possibility to use an inverse delay with definite minimum time cut off timer (IDMT).

The inverse delay operate time is calculated according to a general formula where the constants are made settable which means that many different IDMT curve types (i.e. IEC, IEEE, I^2t etc.) can be represented.

Operating time for all IDMT curves can be described by the following general equation:

$$t_{op} = k \times \left[\frac{A}{\left(\frac{I}{I_{pickup}}\right)^{P} - C} + B \right]$$

where:

k is time multiplier (parameter setting)

A, B, C & P specific constants for every type of curve. Please refer to the RET 521 *2.5 Application manual for description of parameter settings for different types of standardised inverse time characteristics.

I is measured current (selected acc. to setting of CurrentInput parameter) from connected three-phase group to G3I input of GF function block.

Ipickup is the current pickup value and will be according to the following

1 Ipickup = IsetLow for GF function when voltage and current restrain and direction functionalities are disabled.

2 Ipickup = IsetLow for GF function, if current restrain option is used. It means that Ipickup in the inverse time formula not is dependent on the current restrain quantity.

3 Ipickup = IsetLow for GF function, if direction principle I*cos(Φ) is used. It means that Ipickup in the inverse time formula not is dependent on the angle, cos(Φ).

4 Ipickup = The actual voltage controlled current operate value, if voltage restrain option is used.

As an example the IEC Normal Inverse characteristic is made as follows

The Normal Inverse delay is defined by the following expression

$$t_{op} = k \times \left[\frac{0,14}{\left(\frac{I}{I_{pickup}}\right)^{0,02} - 1} + 0 \right]$$

A=0,14 IEC Normal Inverse
B=0
C=1
p=0,02

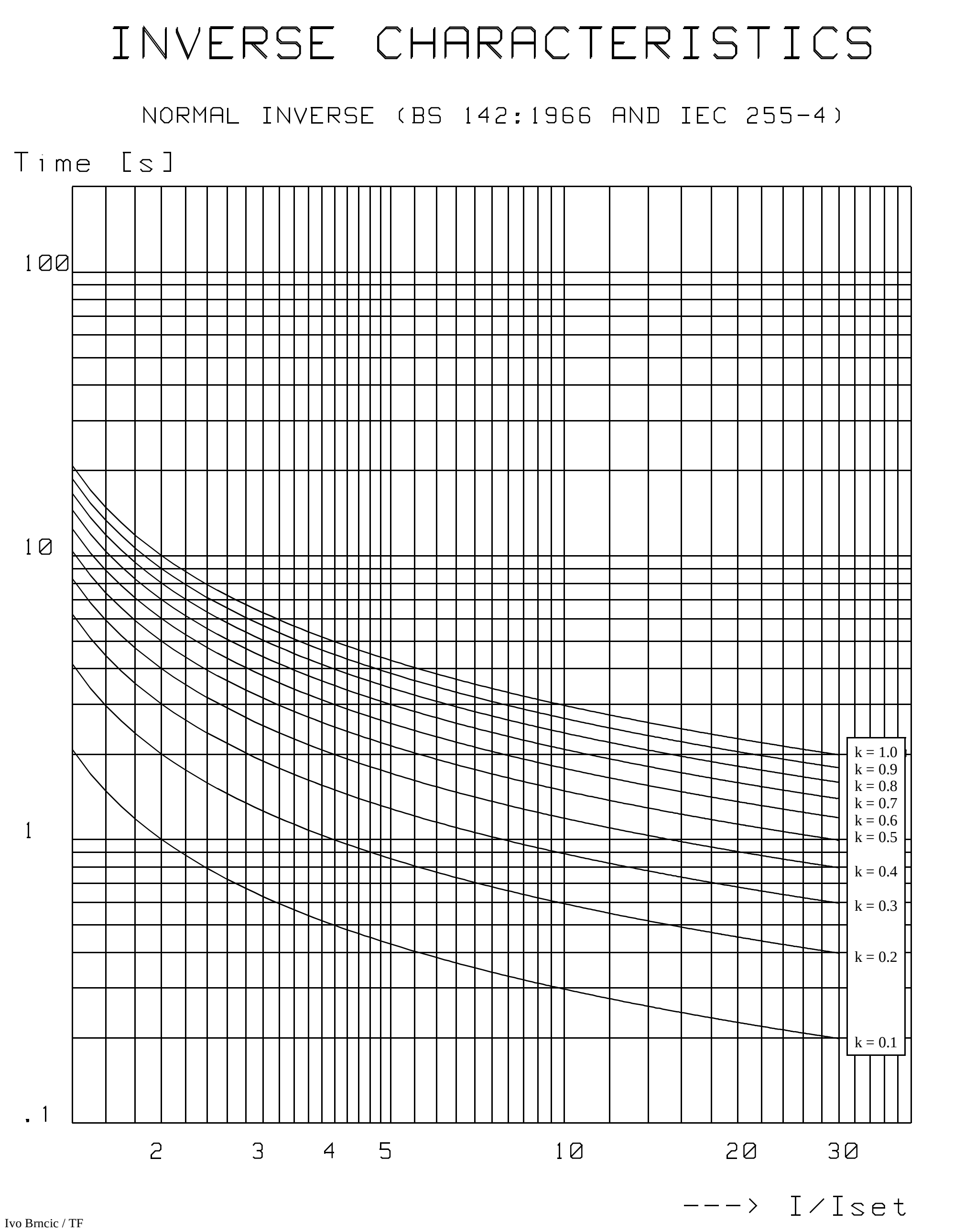


Fig. 66 Example of inverse time characteristic

27.2.3.2 Calculation of inverse delays

Expression for the operate time t_{op}, can be re-written as:

$$(t_{op} - k \times B) \times \left(\left(\frac{I}{I_{set}}\right)^p - C\right) = k \times A = const$$

This expression tells that the operate time (t_{op}- k*B) is a function of the mean value of the variable [$(I/I_{set})^p$ - C], which in turn is a function of the variable I/I_{set}. The operate time (t_{op}-k*B) will be inversely proportional to the mean value of variable [$(I/I_{set})^p$ - C] up to the point of trip. In an integral form, the decision to trip is made at time *t* when:

$$\int_0^t \left(\left(\frac{I(t)}{I_{set}}\right)^p - C\right) \times dt \geq k \times A = const$$

A numerical relay must instead make a sum:

$$\Delta t \times \sum_{j=1}^{n} \left(\left(\frac{I(j)}{I_{set}}\right)^p - C\right) \geq k \times A = const$$

where:

j = 1 a fault has been detected, for the first time it is $I / I_{set} > 1$

Δt time interval between two successive executions of GF function. In the 50 Hz system GF protection is executed with an execution frequency f_{ex} = 250 Hz, then Δt = 1/250 s = 4 ms.

n an integer, the number of the GF function execution intervals Δt from the inception of the fault to the point of time when the above condition for trip is fulfilled and trip command issued.

I(j) value of the fault current at point in time j.

27.2.3.3 Reset time

When inverse time setting is used it is also possible to change from momentarily reset time to a user settable reset time. This means that if the GF function has started but not tripped for a fluctuating input signal (sometimes above operate level and sometimes below operate level) it will reset exponentially according to the setting parameter Currents/tReset during the times the input signal value is below the operate level. The accumulation counter will therefore not necessarily start from zero when input signal increases above operate level again. For exponential decay the content of the accumulation counter is at each execution multiplied with a factor

$$e^{-\left(\frac{\Delta t}{tReset}\right)}$$

where Δt is execution cycle time in s (0.004 for 50 Hz and 0.0032 for 60 Hz). tReset is then the time constant setting.

In order to have a final cutoff, a level of 1% of the operate value for the accumulation counter will give a momentarily reset.

It is thus to be observed that it is only during the time that the trip still not has been activated that a delayed reset can be used.

However if a blocking is done as an effect of an active binary block signal BLKOCLS or if a blocking is made due to a high 2nd harmonic content or due to current restraining the reset will always be momentarily.

27.2.4 Second harmonic blocking

The second harmonic restrain is enabled independently for lowset and highset stage with the settings 2harLow respective 2harHigh. Both stages use the same setting I2/I1ratio, in order to detect if the second-to-first harmonic ratio exceeds this value. The output, I2BLK, is set to 1 if the ratio is above the limit.

The second harmonic restrain is not relevant for certain current input options and is therefore disabled at the CurrentInput settings PS, NS and UNB.

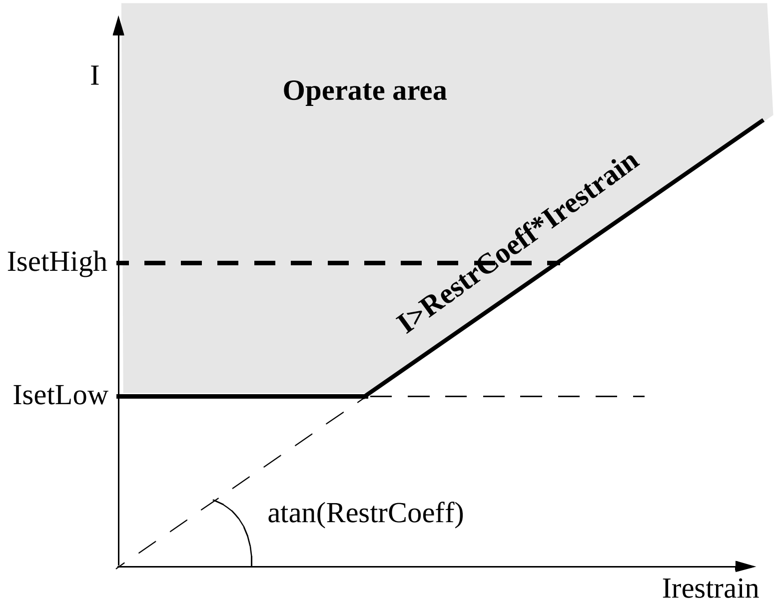
27.2.5 Current restrained functionality

The operation of the high and low stages overcurrent measuring functions can be made dependent of a restraining quantity as shown in the characteristic below. The operate level then becomes higher if the restraining quantity increases.

The function is enabled with the OperIrestr parameter and the restraining quantity have to be chosen with RestrCurr to either

PS	Positive sequence current of the connected three-phase group
NS	Negative sequence current of the connected three-phase group
3ZS	Three times the zero sequence current of the connected three-phase group
MAX	Maximum amplitude of the three phase currents in the group

The RestrCoeff parameter decides the angle (percentage) of the restraining line in the characteristic.



Current restrain characteristic

The Low measuring stage will operate if the current is above both limits
I> (IsetLow and RestrCoeff*Irestrain)

The High measuring stage will operate if the current is above both limits
I> (IsetHigh and RestrCoeff*Irestrain)

When an IDMT timer is used to give the delay before a trip, it has to be observed that the reference value still is equal to the IsetLow value even if the actual pickup value should be higher than IsetLow as an effect of the restraining quantity. The overcurrent ratio used to calculate the delay is therefore equal to the ratio I/IsetLow.

27.2.6 Directional characteristics

With a three-phase voltage group connected to the GF, the current measuring function can be made directional.

Since the voltage and current inputs are independently settable with VoltageInput/CurrentInput it is really important to know what to set to get relevancy of the direction functionality. See the RET 521 *2.5 Application manual for more details about different power system related setting possibilities.

The directionality is then enabled separately for the lowset and the highset stages with the parameters DirectionLow/DirectionHigh which have got the alternatives NonDir, Forward and Reverse.

The choice unbalance UNB on VoltageInput or CurrentInput does not give any relevant direction for the GF function and is therefore always nondirectional even if DirectionLow or DirectionHigh is set to something else.

As said the direction can be set Forward or Reverse. The reference is then defined so that Forward means that the operation area is out towards the net as in Fig. 67 below. The current reference is defined positive for current flowing into the protected object. In order to achieve the direction convention for the special cases where negative sequence or three times zero sequence voltage is used as reference these reference voltages are multiplied by a minus one.

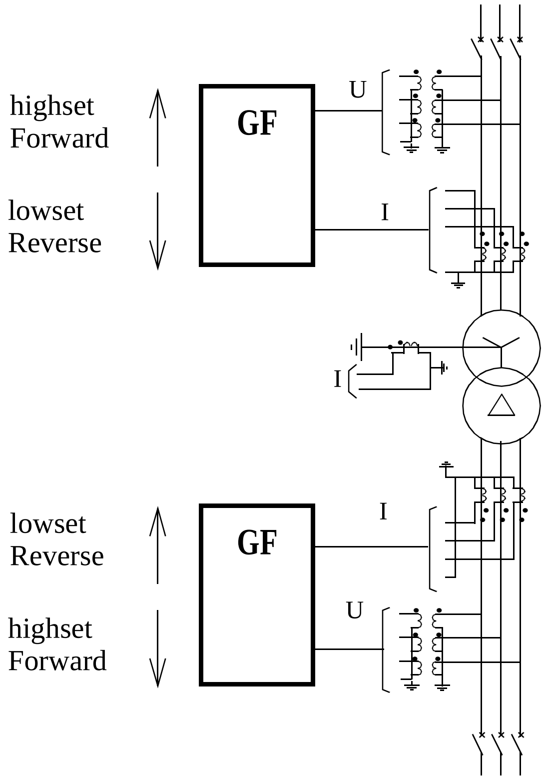


Fig. 67 GF directionality references (CTstarpoint=ToObject)

The characteristic angle and the directional limits of the operate area is determined by the setting parameters roa and rca respectively. See Fig. 68 and Fig. 69 below.
The characteristic angle rca is the angle between mta (maximum torque line) and the reference voltage. For positive rca the mta is leading the reference voltage.

.

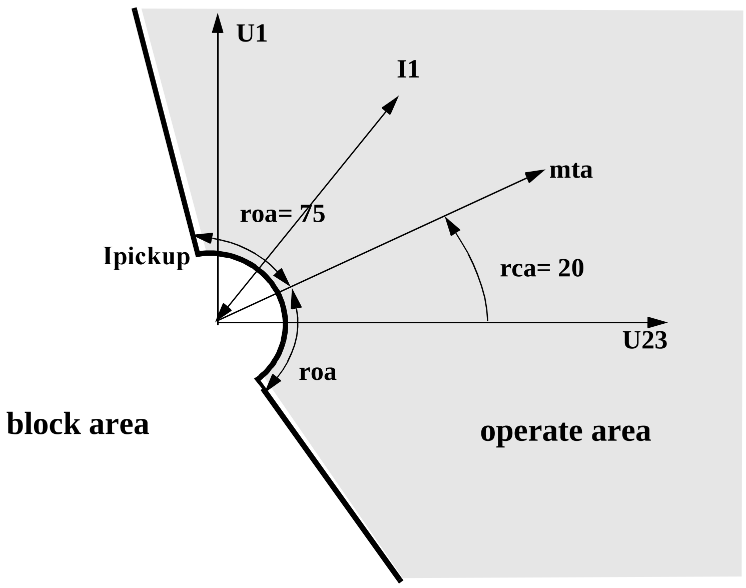


Fig. 68 Directional characteristic of GF in an overcurrent application for phase L1

.

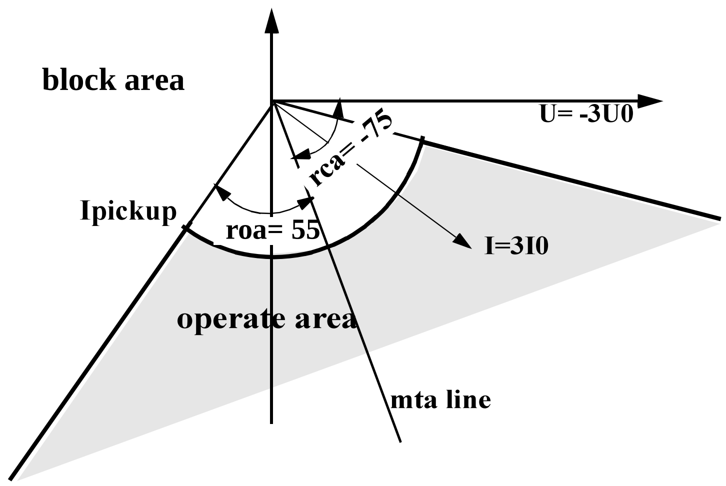


Fig. 69 Directional characteristic of GF in an earth fault application

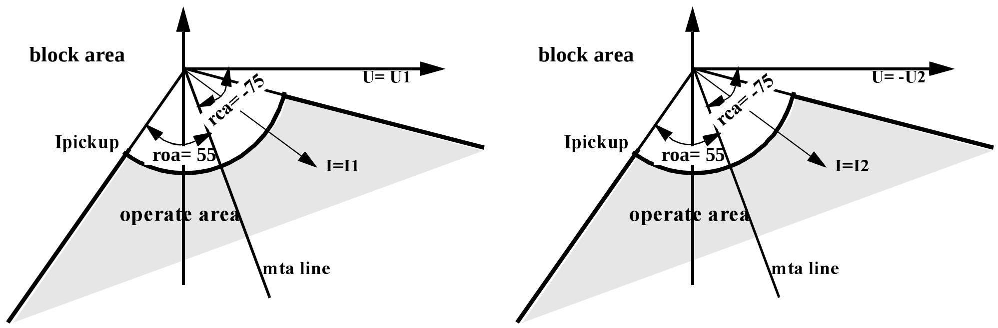


Fig. 70 Directional characteristic of GF when supplied with positive sequence and negative sequence components

The minimum voltage level used for a secure and dependable operation of the directional function is settable by the setting parameter UminOper. Below the UminOper level the over current function can be set to either be totally blocked or to be nondirectional. This is done with help of the parameters UActionLow and UActionHigh.

27.2.6.1 Directional operation with I*cos(Φ) measurement

The operate level of the GF can also be made depending on the angle between current and maximum torque angle (mta) by setting the DirPrincLow or DirPrinchigh parameter to ICosFi&U. Then we get a straight line operate characteristic instead of a circular operate characteristic. The mta angle can be shifted from the reference voltage by the relay characteristic angle (rca). The directional limits decided by the roa setting can still be used. Se Fig. 71 below.

The expression for the linear operation characteristic will be

I*cos(Φ) > IsetLow
I*cos(Φ) > IsetHigh

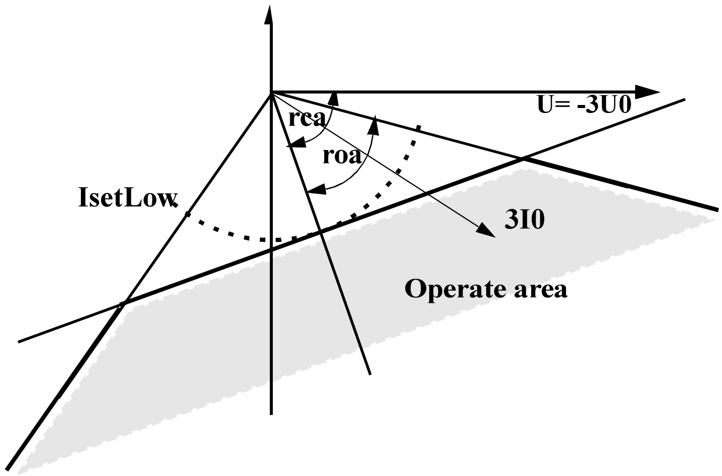


*Fig. 71 Directional characteristic for GF lowset stage with I*cos(Φ) measurement*

27.2.7 Voltage restrained/controlled GF-functionality

This option make pickup level of the GF function variable in accordance with the magnitude of the measured voltage. Once correct pickup level is determined for each function execution, the function continuous to work as earlier. Fig. 72 gives an example how current pickup levels may vary with voltage magnitude.

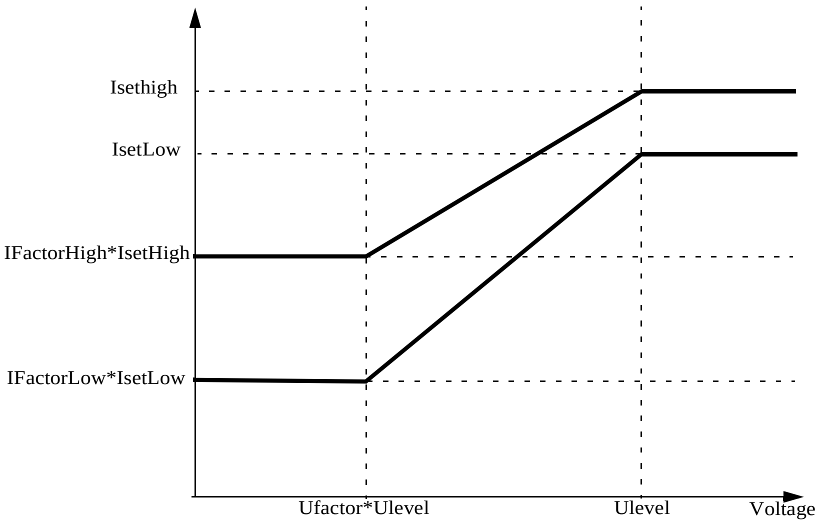


Fig. 72 Current Pickup variation with Measured Voltage Magnitude

Voltage controlled functionality is obtained when IfactorLow or IfactorHigh are set to different value than 1.00, while Ufactor is kept to the default value of 0.99. Then practically mid portion of the characteristic from Fig. 72 is omitted and only first and third part of the characteristic are used.

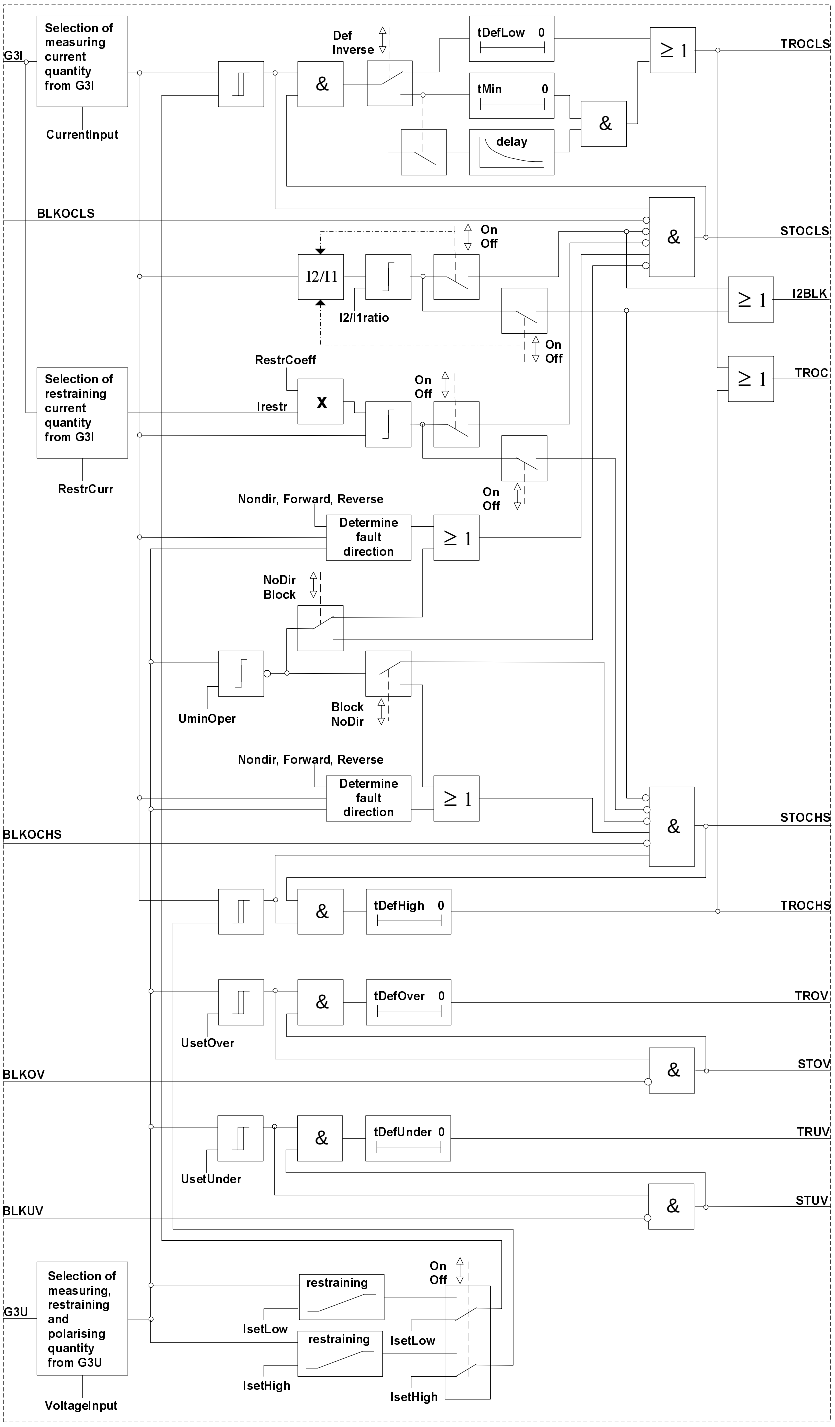
Voltage restrained functionality is obtained when IfactorLow, IfactorHigh & Ufactor are set to some different values from the default ones.

The voltage controlled pickup value is also used as pickup value in the IDMT time characteristic which therefore is influenced by the restraining voltage.

It is actually possible to simultaneously use IDMT curve, directionality and voltage controlled/restrained features.

27.3 Logic diagram

GF - Directional

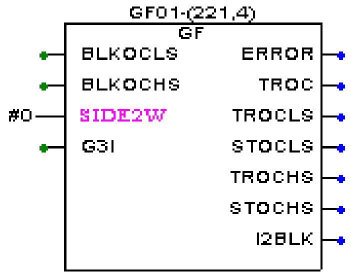


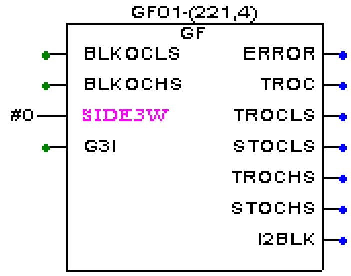
en03000166.vsd

27.4 Function block

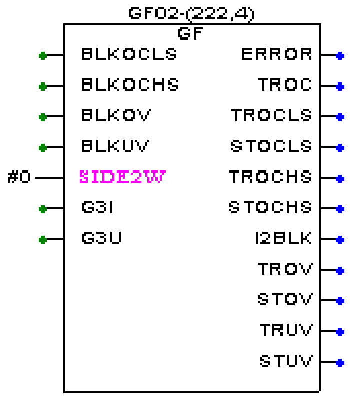
For General Protection Function, GF, there are two different kinds of the function block. (Left: 2-winding power transformers, right: 3-winding transformers.)

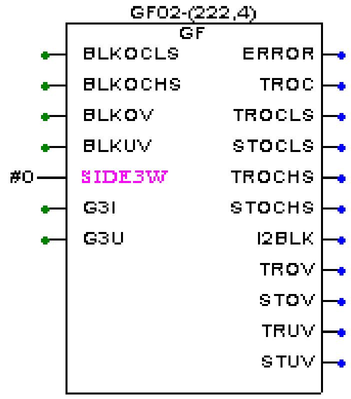
Nondirectional GF (Function Selector G3I). Three-phase currents have to be connected to the analog input G3I.





Directional GF (Function Selector G3I+G3U). Three-phase currents and three-phase voltages have to be connected to the analog input G3I and G3U respectively.





27.5 Input and output signals

Table 75: GF function block: input signals (x = 1, 2, ...12))

In:	Description:
GFx:BLKOCLS	External block of lowset current, GFx
GFx:BLKOCHS	External block of highset current, GFx
GFx:BLKOV	External block of overvoltage, GFx
GFx:BLKUV	External block of undervoltage, GFx
GFx:SIDE2W or GFx:SIDE3W	Transformer side, GFx
GFx:G3I	Three phase current group, GFx
GFx:G3U	Three phase voltage group, GFx

Table 76: GF function block: output signals (x = 1, 2, ...12)

Out:	Description:	Type	Range
GFx:ERROR	General GFx function error	Int	0 - 1
GFx:TROC	Common trip overcurrent, GFx	Int	0 - 1
GFx:TROCLS	Trip overcurrent lowset, GFx	Int	0 - 1
GFx:STOCLS	Start overcurrent lowset, GFx	Int	0 - 1
GFx:TROCHS	Trip overcurrent highset, GFx	Int	0 - 1
GFx:STOCHS	Start overcurrent highset, GFx	Int	0 - 1
GFx:I2BLK	Second harmonic block, GFx	Int	0 - 1
GFx:TROV	Trip overvoltage, GFx	Int	0 - 1
GFx:STOV	Start overvoltage, GFx	Int	0 - 1
GFx:TRUV	Trip undervoltage, GFx	Int	0 - 1
GFx:STUV	Start undervoltage, GFx	Int	0 - 1

27.6 Setting parameters and ranges

Table 77: GF- settings, their ranges and descriptions

Parameter:	Range	Description:
CurrentInput	0 - 13	Measuring Current Input
IrUserDef	1 -99999	Rated current for user defined side, in A
VoltageInput	0 - 13	Measuring Voltage Input
UrUserDef	0.1 -999.9	Rated voltage for user defined side, in kV
Operation	0 - 1	Operation General Function, Off/On
BlockLow	0 - 1	Block lowset, Off/On
IsetLow	2 -5000	Start current, lowset in % of Ir
tDefLow	0.00 - 300.00	Definite delay lowset in sec.
CurveType	0 - 1	Time characteristic for lowset GFxx, DEF/INVERSE
tMin	0.05 - 200.00	Minimum operating time in sec.
k	0.05 - 999.00	Time multiplier for inverse time lowset stage
A	0.0000 - 999.0000	Constant A of inverse time curve, lowset stage
B	0.0000-99.0000	Constant B of inverse time curve, lowset stage
C	0.0000-1.0000	Constant C of inverse time curve, lowset stage
P	0.0001-4.0000	Constant P of inverse time curve, lowset stage
tReset	0.00 - 600.00	Reset time constant in ms for inverse time
I2/I1ratio	5 - 100	Second to first harmonic ratio in %
2harLow	0 - 1	2nd Harmonic stabilization lowset, Off/On
BlockHigh	0 - 1	Block highset, Off/On
IsetHigh	2 -5000	Start current, highset in % of Ir
tDefHigh	0.00 - 300.00	Definite delay highset in sec.
2harHigh	0 - 1	2nd Harmonic stabilization highset, Off/On
OperIrestr	0 - 1	Operation Current restrain feature, Off/On
RestrCurr	0 - 3	Restraining Current Input
RestrCoeff	0.00 - 5.00	Restrain coefficient
OperVoltage	0 - 1	Operation Over &Under Voltage, Off/On
BlockOver	0 - 1	Block overvoltage function, Off/On
BlockUnder	0 - 1	Block undervoltage function, Off/On
UsetOver	3.0 - 200.0	Start overvoltage in % of Ur
UsetUnder	3.0 - 200.0	Start undervoltage in % of Ur
tDefOver	0.00 - 300.00	Definite delay overvoltage function in sec.
tDefUnder	0.00 - 300.00	Definite delay undervoltage function in sec.

Table 77: GF- settings, their ranges and descriptions

Parameter:	Range	Description:
DirectionLow	0 - 2	Direction for trip, lowset, NonDir/Forward/Reverse
DirectionHigh	0 - 2	Direction for trip, highset, NonDir/Forward/Reverse
rca	-180 to +180	Relay Characteristic Angle in deg.
roa	1 to 120	Relay Operate Angle in deg.
DirPrincLow	0 - 1	Directional operation principle lowset
DirPrincHigh	0 - 1	Directional operation principle highset
UminOper	1.0- 200.0	Minimum Voltage Operation for directional feature
UActionLow	0 - 1	Action low pol. voltage, lowset, NonDir/Block
UActionHigh	0 - 1	Action low pol. voltage, highset, NonDir/Block
OperUrestr	0 - 1	Operation Voltage restrain feature, Off/On
ULevel	1.0- 200.0	Voltage level for restrained feature in % of Ur
UFactor	0.03 - 0.99	Factor giving lower level voltage for restraining
IFactorLow	0.03 - 5.00	Factor giving lower level of lowset current for restraining
IFactorHigh	0.03 - 5.00	Factor giving lower level of highset current for restraining

The grey marked setting parameters have no significance if the function selector in CAP is set to G3I so that no voltage input to the function block exists.

27.7 Service report values

Table 78:

Parameter:	Range:	Step:	Description:
Imeasured	0.0 - 99999.9	0.1	Measured current in A
Umeasured	0.0 - 999.9	0.1	Measured voltage in kV

28 Restricted earth fault protection (REF)

28.1 Summary of application

The Restricted Earth Fault (REF) protection is meant to protect a single winding of a power transformer. The winding which should be protected must be earthed. In the case of delta windings, the winding must be earthed by an earthing transformer, which must be electrically placed between the winding and the current transformers.

Protection against a fault to earth within the power transformer can ordinarily be taken care of by the overall differential protection. It is usually sufficiently sensitive to make special protection unnecessary in cases where the neutral of a transformer is earthed directly or through a small resistor.

If the REF protection is applied even when the neutral is solidly earthed, a complete cover for earth faults is obtained, since the fault current remains at a high value virtually to the last turn of the winding.

In the case of a transformer with its neutral earthed through a high resistance which keeps the earth faults at a relatively low level, overall differential protection (DIFP) should be supplemented by REF protection. The differential protection does not cover a power transformer earthed through a high resistance or reactance against internal earth faults affecting less than approximately 20% to 30% of a winding near the neutral point. A solution to this problem is the REF protection.

REF is a unit protection of (low impedance) differential type, which operates only for earth faults on the protected winding. It is in principle insensitive to phase-to-phase faults, both internal or external, or earth fault external to the zone protected by REF. Within the zone of protection are all elements between the ct in the neutral conductor, and cts in the feeder(s). Up to two feeders connected to the power transformer bus may be included in the protected zone.

REF is based on the fundamental harmonic component of currents, and is thus insensitive to the 3-rd harmonic components which used to be a problem for older types of (high impedance) restricted earth fault protections. All harmonics are efficiently suppressed.

REF is a protection of differential type. As such, it calculates a differential current and a bias current. The differential current is a vectorial difference of the neutral current (i.e. current flowing in the neutral conductor) and the residual current from the lines. For internal faults, this difference is equal to the total earth fault current. REF operates on the fault current only, and is not dependent on eventual load currents. This makes REF a very sensitive protection.

28.2 Summary of function

- Restricted earth fault protection (REF) is a unit protection of differential type with good sensitivity and selectivity.
- REF gives a fast and selective protection of earthed power transformer windings.
- REF is of low-impedance type where differential current is calculated numerically.
- Up to 3 power transformer windings can be protected by up to 3 instances of the restricted earth fault protection.
- Bus with 2 circuit breakers can be included in the zone of protection.
- Differential current is a vectorial difference between neutral and residual current.
- Residual current is constructed from fundamental frequency terminal currents.
- Differential current is for internal faults equal to total earth fault current.
- The relatively highest of all separate input currents serves as a bias current.
- REF is insensitive to initial, recovery and sympathetic inrush, or overexcitation.
- REF is insensitive to On Load Tap Changer switching.
- If a heavy external earth fault is detected, REF is temporarily desensitized.
- A directional criterion is applied in order to increase stability against heavy external faults with ct saturation.
- Two consecutive trip requests are necessary for a final trip signal by REF.

28.3 Measuring principles

28.3.1 Fundamental principles of the restricted earth fault protection (REF)

The REF protection should detect earth faults on earthed power transformer windings. The REF protection is a unit protection of differential type. Because this protection is based on the zero sequence currents, which theoretically only exist in case of an earth fault, the REF can be made very sensitive; regardless of normal load currents. It is the fastest protection a power transformer winding can have. It must be borne in mind, however, that the high sensitivity, and the high speed, tend to make such a protection instable, and special measures must be taken to make it unsensitive to conditions, for which it should not operate, for example heavy through faults of phase-to-phase type, or heavy external earth faults.

The REF protection is of “low impedance” type. At least 3 power transformer terminal currents, and the power transformer neutral conductor current, must be fed separately to RET 521. These input currents are then conditioned within RET 521 by mathematical tools. Fundamental frequency components of all currents are extracted from all input currents, while other eventual zero sequence components (e.g. the 3-rd harmonic currents) are fully suppressed. Then the residual current phasor is constructed from the three line current phasors. This zero sequence current phasor is then vectorially subtracted from the neutral current, which is “per definition” of zero sequence.

The following facts may be observed from Fig. 73 and Fig. 74 (where the 3 line CTs are lumped into a single summation transformer, for the sake of simplicity).

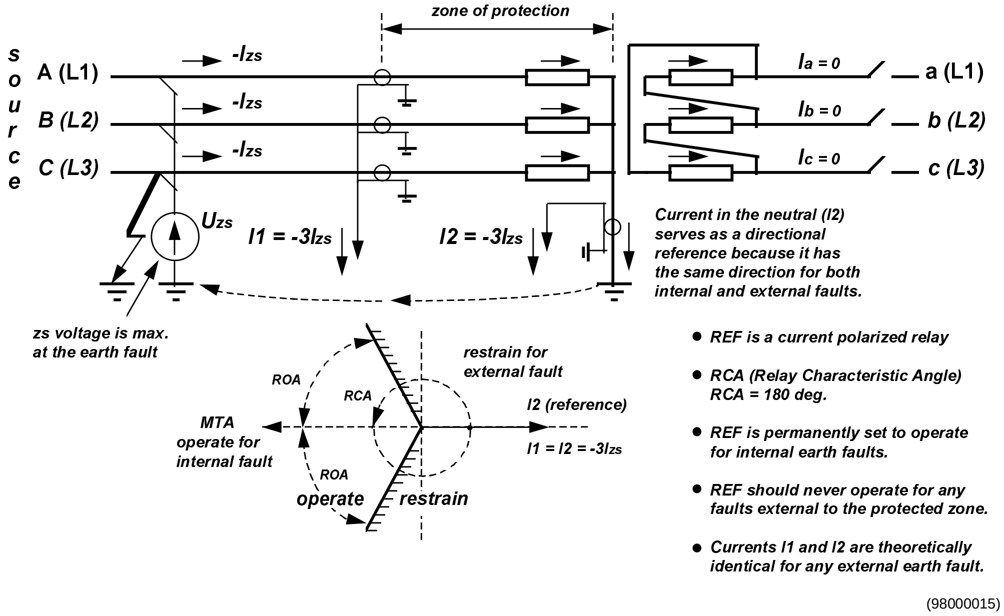


Fig. 73 Currents at an external earth fault. For simplicity, the residual current is designated in the figure as I1. This current is actually calculated inside RET 521 from 3 separate terminal input currents by a C3P function block. In practice, the CTs can be oriented (earthed) in any other way, or combination.

1 For an external earth fault, the residual current (I1 in Fig. 73) and the neutral conductor current (I2 in Fig. 73) are equal, and of the same direction. This is easy to understand, as both CTs ideally measure the same earth fault current.

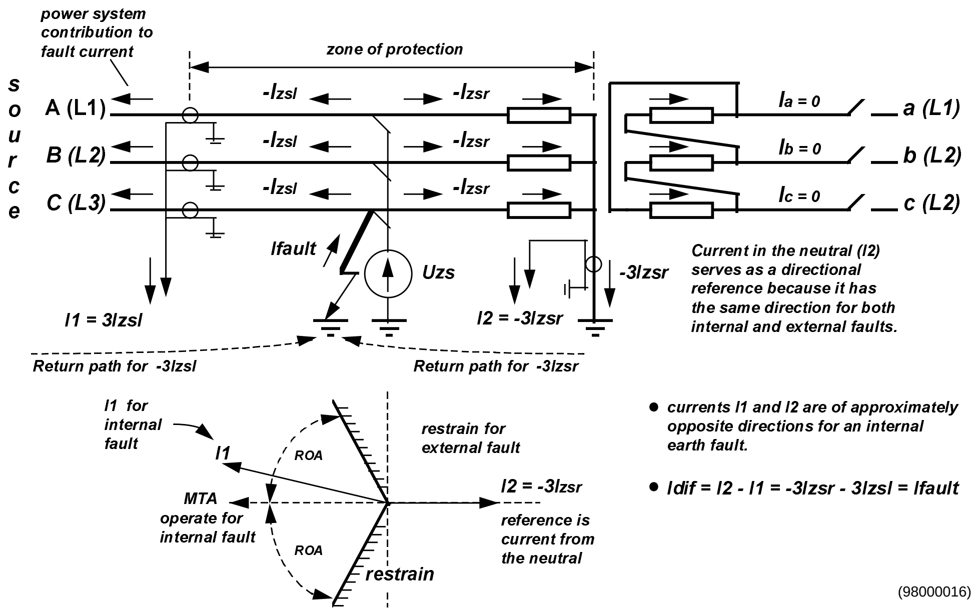


Fig. 74 Currents at an internal earth fault. For simplicity, the residual current is designated in the figure as I1. This current is actually calculated inside RET 521 from 3 separate terminal input currents by a C3P function block. In practice, the CTs can be oriented (earthed) in any other way, or combination.

2 For an internal fault, the total earth fault current (Ifault) is composed generally of two components. One component (-3Izsr) flows towards the power transformer neutral point and into the earth, while the other component (-3Izsl) flows out into the power system. These two currents can be expected to be of approximately opposite directions (about the same zero sequence impedance angle is assumed on both sides of the earth fault). The magnitudes of the two components may be different, dependent on the magnitudes of zero sequence impedances of both sides. No current can flow towards the power system, if the only point where the system is earthed, is at the protected power transformer. Likewise, no current can flow into the power system, if the winding is not connected to the power system (circuit breaker open and power transformer energized from the other side).

3 For both internal and external earth faults, the current in the neutral connection (I2 = -3Izsr) has always the same direction, that is, towards the earth.

4 The two components of the fault current are measured as I1 and I2. The vectorial difference between them is the differential current which is equal to the total earth fault current; Idif = I2 - I1 = Ifault.

Because REF is a differential protection where the line zero sequence (residual) current is constructed from 3 line (terminal) currents, a bias quantity must give stability against false operations due to high through fault currents. An operate - bias characteristic (only one) has been devised to the purpose.

It is not only external earth faults that REF should be stable against, but also heavy phase-to-phase faults, not including earth. These faults may also give rise to false zero sequence currents due to saturated line CTs. Such faults, however, produce no neutral current, and can thus be eliminated as a source of danger, at least during the fault.

As an additional measure against unwanted operation, a directional check is made in agreement with the above points 1, and 2. An operation is only allowed if currents I1 and I2 (see Fig. 73 and Fig. 74) are at least RCA - ROA degrees apart, where RCA is the Relay Characteristic Angle, and ROA is the Relay Operate Angle. By taking a smaller ROA, the REF protection can be made more stable under heavy external fault conditions, as well as under the complex conditions, when external faults are cleared by other protections.

28.3.2 REF as a Differential Protection

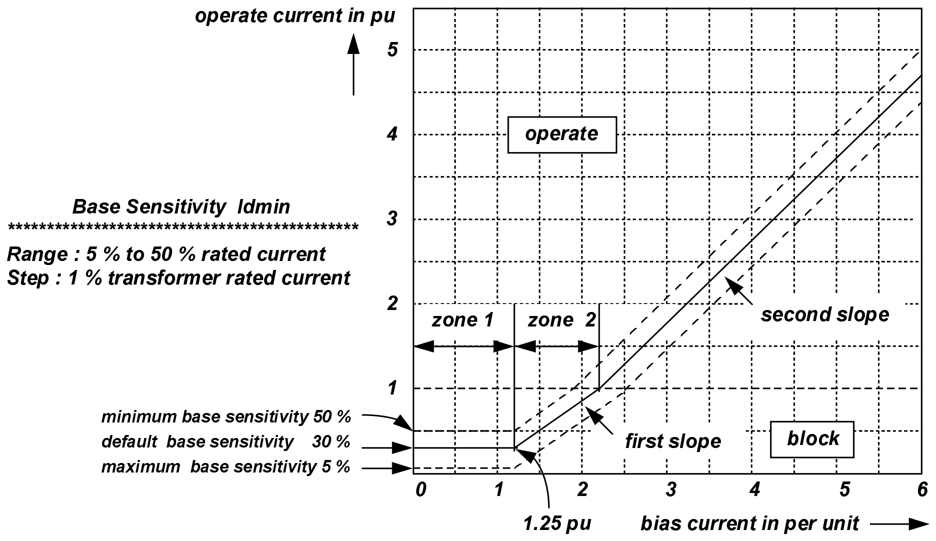
The REF protection is a protection of differential type, a unit protection, whose settings are independent of any other protection. Compared to the overall differential protection (DIFP) it has some advantages. It is simpler, as no current phase correction and magnitude correction are needed, not even in the case of an eventual On-Load-Tap-Chager (OLTC). REF is not sensitive to inrush and overexcitation currents. The only danger left is an eventual current transformer saturation.

The REF has only one operate-bias characteristic, which is described in Table 79:, and shown in Fig. 75.

Table 79: Data of the operate - bias characterize of the REF.

Default sensitivity Idmin (zone 1)	Max. base sensitivity Idmin (zone 1)	Min. base sensitivity Idmin (zone 1)	End of zone 1	First slope	Second slope
% Irated	**% Irated**	**% Irated**	**% Irated**	**%**	**%**
30	5	50	125	70	100

As a differential protection, the REF calculates a differential current and a bias current. In case of internal earth faults, the differential current is theoretically equal to the total earth fault current. The bias current is supposed to give stability to REF protection. The bias current is a measure of how high the currents are, or better, a measure of how difficult the conditions are under which the CTs operate. The higher the bias, the more difficult conditions can be suspected, and the more likely that the calculated differential current has a component of a false current, primarily due to CT saturation. This “law” is formulated by the operate-bias characteristic. This characteristic divides the Idif - Ibias plane into two parts. The part above the operate - bias characteristic is the so called operate area, while that below is the block area, see Fig. 75.



(98000017)

Fig. 75 Operate - bias characteristic of the restricted earth fault protection REF.

28.3.3 Calculation of Differential Current and Bias Current

The differential current, (= operate current), as a fundamental frequency phasor, is calculated as (with designations as in Fig. 73 and Fig. 74)

$\bar{I}\mathrm{dif} = \bar{I}\mathrm{op} = \bar{I}2 - \bar{I}1$,

where:

$\bar{I}2$ current in the power transformer neutral as a fundamental frequency phasor,

$\bar{I}1$ residual current of the power transformer line (terminal) currents as a phasor.

If there are 2 feeders included in the zone of protection of the REF protection (such as in breaker-and-a-half configurations), then their respective residual currents are added within RET (by C3C CAP module) so that:

$\bar{I}1 = \bar{I}1\_\mathrm{feeder1} + \bar{I}1\_\mathrm{feeder2}$.

The bias current is a measure (expressed as a current in Amperes) of how difficult the conditions are under which the instrument current transformers operate. Dependent on the magnitude of the bias current, the corresponding zone (section) of the operate - bias characteristic ia applied, when deciding whether “to trip, or “not to trip”. In general, the higher the bias current, the higher the differential current required to produce a trip.

As the bias current the highest current of all separate input currents to REF protection, that is, of current in phase L1, phase L2, phase L3, and the current in the neutral connection, In (designated as I2 in Fig. 73 and Fig. 74).

If there are 2 feeders included in the zone of protection of the REF protection, then the respective bias current is found as the relatively highest of the following currents:

current[1] = IAf1 / CTprim * Irated,

current[2] = IBf1 / CTprim * Irated,

current[3] = ICf1 / CTprim * Irated,

current[4] = IAf2 / CTprim * Irated,

current[5] = IBf2 / CTprim * Irated,

current[6] = ICf2 / CTprim * Irated,

current[7] = IAf1 + IAf2,

current[8] = IBf1 + IBf2,

current[9] = ICf1 + ICf2,

current[10] = In / CTprim * Irated

The bias current is thus generally equal to none of the input currents. If all primary ratings of the CTs were equal to Irated, then the bias current would be equal to the highest current in Amperes. Irated is the rated current of the power transformer side (winding) where the REF protection is applied.

An exception to the above rule is when CTprim < Irated. In such cases, Irated is taken instead of CTprim in the above expressions.

28.3.4 Detection of External Earth Faults

External faults are more common than internal earth faults for which the restricted earth fault protection should operate. It is important that the restricted earth fault protection remains stable during heavy external earth and phase-to-phase faults, and also when such a heavy external fault is cleared by some other protection such as overcurrent, or earth fault protection, etc. The conditions during a heavy external fault, and particularly immediately after the clearing of such a fault may be complex. The circuit breaker’s poles may not open exactly at the same moment, some of the CTs may still be highly saturated, etc.

The detection of external earth faults is based on the fact that for such a fault a high neutral current appears first, while a false differential current only appears if and when one, or more, current transformers saturate. An external earth fault is thus assumed to have occurred when a high neutral current suddenly appears, while at the same time the differential current Idif remains low, at least for a while. This condition must be detected before a trip request is placed within REF protection. Any search for external fault is aborted if a trip request has been placed. A condition for a successful detection is that it takes not less than 4 ms for the first CT to saturate.

For an internal earth fault, a true differential current develops immediately, while for an external fault it only develops if a CT saturates. If a trip request comes first, before an external fault could be positively established, then it must be an internal fault.

If an external earth fault has been detected, then the REF is desensitised. Under external earth fault condition, no trip is allowed if the current in the neutral connection is less than 50% rated current. The condition is removed when the external earth fault is found to be cleared. The external earth fault is considered to be cleared when the neutral current falls below 50% of the set base sensitivity of the REF protection, Idmin.

Directional criterion

The directional criterion is applied in order to positively distinguish between internal- and external earth faults. This check is an additional criterion, which should prevent misoperations at heavy external earth faults, and during the disconnection of such faults by other protections. Earth faults on lines connecting the power transformer occur much more often than earth faults on a power transformer winding. It is important therefore that the restricted earth fault protection (REF) should remain secure during an external fault, and immediately after the fault has been cleared by some other protection.

For an external earth fault with no CT saturation, the residual current in the lines (I1 in Fig. 73) and the neutral current (I2 in Fig. 73) are theoretically equal in magnitude and phase. It is the current in the neutral (I2) which serves as a directional reference because it flows for all earth faults, and it has the same direction for all earth faults, both external as well as internal. The directional criterion in REF protection makes REF a current-polarized relay.

If one or more CTs saturate, then the measured currents I1 and I2 may no more be equal, nor will their positions in the complex plane be the same. There is a risk that the resulting false differential current Idif enters the operate area when clearing the external fault. If this happens, a directional test may prevent a misoperation.

A directional check is only executed if:

1 a trip request signal has been issued, (REF function block STARTsignal set to 1)

2 if the residual current in lines (I1) is at least 3% of the power transformer rated current.

If a directional check is either unreliable or not possible to do, due to too small currents, then the direction is cancelled as a condition for an eventual trip.

If a directional check is executed, the REF protection is only allowed to operate, if the two currents which are being compared (I1 and I2) are at least 180 - ROA electrical degrees apart, see Fig. 73, Fig. 74, and Fig. 75, where ROA was 75 degrees. Quantities which describe the directional boundary of the REF protection are the following:

RCA = 180 degrees = constant; where RCA stands for the Relay Characteristic Angle,

ROA = ±60 to ±90 degrees; where ROA stands for the Relay Operate Angle.

RCA determines a direction MTA (“Maximum Torque Angle”) where the line residual current I1 should lie for an internal earth fault, while ROA sets a tolerance margin.

2:nd harmonic analysis

At energising of a reactor a false differential current may appear in REF even though it does not exist in the primary net. The phase CT’s may saturate due to a high dc-component with long duration whereas the current through the neutral CT do not have either the same dc-component or the same amplitude and the risk for saturation in this CT is much lesser. The appearing differential current as a result of the saturation may be so high that it reaches the operate characteristic. A calculation of the content of 2:nd harmonic in the neutral current is made when neutral current, residual current and bias current are within some windows and some timing criteria are fulfilled. If the ratio between second and fundamental tone exceeds 60% the REF function then will be blocked.

28.3.5 Algorithm of the restricted earth fault protection (REF) in short

1 Check if current in the neutral Ineutral (I2) is less than 50% of the base sensitivity Idmin. If yes, only service values are calculated, then the REF protection algorithm is exited.

2 If current in the Ineutral (I2) is more than 50% of Idmin, then determine the bias current Ibias.

3 Determine the differential (operate) current Idif as a phasor, and calculate its magnitude.

4 Check if the point P(Ibias, Idif) is above the operate - bias characteristic. If yes, increment the trip request counter by 1. If the point P(Ibias, Idif) is found to be below the operate - bias characteristic, then the trip request counter is reset to 0.

5 If the trip request counter is still 0, search for an eventual heavy external earth fault. The search is only made if the neutral current is at least 50% of the power transformer rated current of the power transformer side where the winding is protected by the REF protection. If an external earth fault has been detected, a flag is set which remains set until the external fault has been cleared. The external fault flag is reset to 0 when Ineutral falls below 50% of the base sensitivity Idmin. Any search for external fault is aborted if trip request counter is more than 0.

6 For as long as the external fault persists an additional temporary condition is introduced, which requires, that Ineutral has to be higher than 50% power transformer rated current, for any TRIP signal to be set by the REF function block. That means that the REF protection is temporarily desensitized.

7 If point P(Ibias, Idif) is found to be above the operate - bias characteristic), so that trip request counter is becomes more than 0, a directional check can be made. The directional check is made only if Iresidual (I1) is more than 3% of the rated current. If the result of the check means “external fault”, then the internal trip request is reset. If the directional check cannot be executed, then direction is no longer a condition for a trip.

8 When neutral current, residual current and bias current are within some windows and some timing criteria are fulfilled the ratio of 2:nd to fundamental tone is calculated and if it is found to be above 60% the trip request counter is reset and TRIP remains zero.

9 Finally, a check is made if the trip request counter is equal to, or higher than 2. If it is, and at the same time, the bias current is at least 50% of the highest bias current Ibiasmax (measured during the disturbance) then the REF function block sets output TRIP to 1. If the counter is less than 2, TRIP signal remains 0.

28.4 Logic diagram

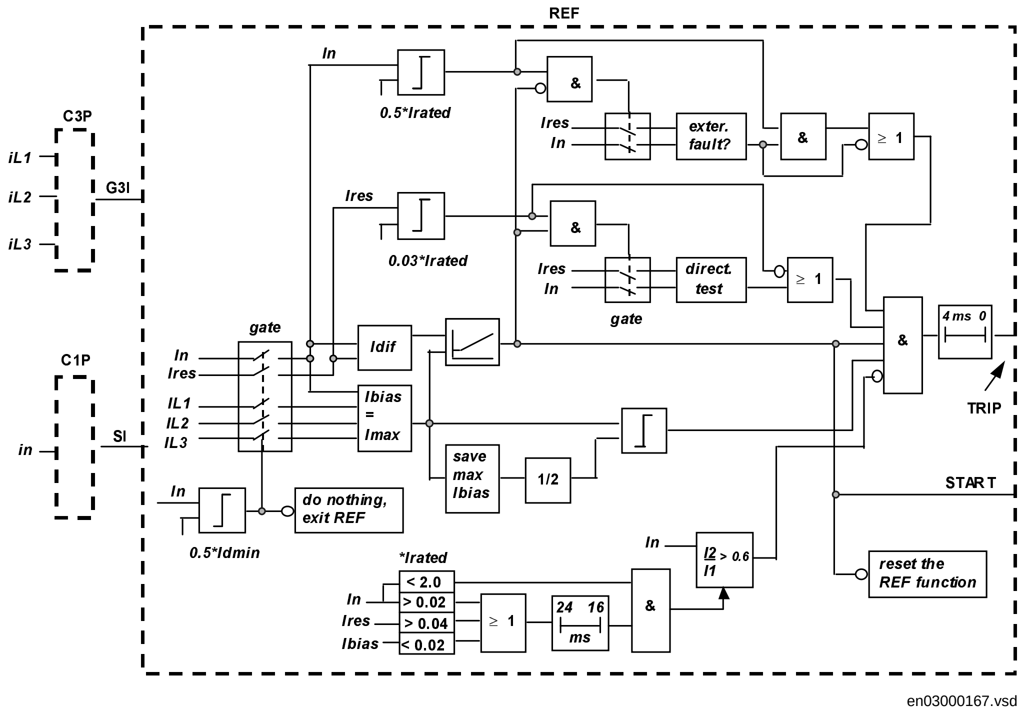


Fig. 76 A simplified logic diagram of the restricted earth fault (REF) protection

28.5 Function block

The restricted earth fault protection (REF) function block, for 2-winding power transformers (on the left), and for 3-winding power transformers (on the right).

28.6 Input and output signals

Table 80: REF protection function block inputs (x = 1, 2, 3)

In:	Description:
REFx:BLOCK	External block, REFx
REFx:SIDE2W or REFx:SIDE3W	Transformer side, REFx
REFx:SINEUT	Neutral current, REFx
REFx:G3I	Three phase current group, REFx

Table 81: REF protection function block outputs (x = 1, 2, 3)

Out:	Description:	Type	Range
REFx:ERROR	General REFx function error	Int	0 - 1
REFx:TRIP	Common trip REFx	Int	0 - 1
REFx:START	Start, REFx	Int	0 - 1

28.7 Setting parameter and ranges

Table 82: REF protection settings, their ranges and descriptions

Parameter:	Range:	Description:
Operation	0 - 1	Operation Restricted Earth Fault Protection, Off/On
Idmin	5 - 50	Maximum sensitivity in % of Ir
roa	60 - 90	Relay Operate Angle in deg.

28.8 Service report values

Table 83: REF protection service report values, their ranges and descriptions

Parameter:	Range:	Step:	Description:
Ibias	0.0 - 99999.9	0.1	Bias current in A
Idiff	0.0 - 99999.9	0.1	Differential current in A

29 Earth fault time-current protection (TEF)

29.1 Application of function

By using a relay which responds only to the zero sequence current of the system, a more sensitive protection against earth faults is obtained, since the zero sequence component theoretically only exists when fault current flows to earth. The earth fault is therefore theoretically unaffected by load currents, and can be given a setting which is much below the rated load currents. This is very useful, as earth faults are by far the most frequent of all faults.

However, a higher sensitivity for fault currents is paid by a higher sensitivity to false zero sequence currents produced by for example unbalanced leakage to earth, or false zero sequence currents produced by cts for high load, heavy external faults not involving earth, or inrush currents. This sets the limit for the lowest setting of the earth fault relay. As a stabilization against inrush currents, the 2-nd harmonic restrain can optionally be applied.

The earth fault protection can be optionally provided with a directional element, based on fundamental frequency zero sequence voltage - calculated internally in RET 521 - or the measured open delta (residual) voltage. A directional earth fault relay can discriminate between the earth faults in front of, or behind, the relay. An earth fault which occurs between the relay and a power transformer with an earthed neutral point, is a fault behind the relay. The earth fault relay will operate for such a fault if its directional setting is Reverse. An earth fault which happens out in the power system on the same side of the power transformer is a fault in front of the relay. The earth fault relay will operate for such an earth fault only if its directional setting is Forward. An earth fault relay operating on the neutral current (i.e. current flowing in the neutral conductor) cannot be directional, as the neutral current always flows up the neutral conductor regardless of the earth fault position with respect to the relay position.

The earth fault protection has two stages. Both of them can be made directional. The stages can look to different directions independent of each other.

The earth fault protection can be applied to protect a power transformer if it is fed with the power transformer currents, or it can protect a feeder connected to the power transformer bus if the earth fault relay is fed with the feeder currents. In this case, all current limits shall be expressed in % of the rated current of the protected feeder (IrUserDef).

Among the various possible methods used to achieve correct earth fault relay coordination are those using either time or current, or a combination of time and current.

In case of the current-independent earthfault relay, the delay is independent of the actual fault current, while in the case of current-dependent relay, the delay is an inverse function of the magnitude of the actually fault current.

There are two delay types available in TEF:

1 Definite

2 Inverse (Normal Inverse, Very Inverse, Extremely Inverse, Longtime Inverse and Logarithmic (the so called RXIDG)

The lowset stage can use all delay types, while the highset stage can only use the definite delay type.

29.2 Summary of function

- Earth fault relays offer a very satisfactory means of clearing earth faults.
- The earth fault time-current protection (TEF protection) can be set very sensitive irrespective of normal load currents.
- The earth fault time-current protection is based on zero sequence current. The zero sequence current may be calculated within the RET terminal from 3 phase input currents, or may be connected to the terminal as a single current.
- Single current can be a direct sum of the 3 separate phase currents, or can be supplied as a single current by a special core-balance current transformer from the transformer neutral.
- Fundamental frequency zero sequence current serves as a basis for comparison and delay. Other harmonics of the zero sequence nature, such as the third, are effectively suppressed.
- The earth fault time-current protection can be stabilized by 2-nd harmonic criterion against misoperation due to inrush.
- Reset ratio is 96%.
- The earth fault time-current protection has a lowset stage, and a highset stage.
- The lowset stage can have either a definite delay, or an inverse delay.
- A definite minimum delay is available for inverse delays.
- The highset stage can only have a definite delay.

- Both stages can be directional or nondirectional, independent of each other.
- If both stages are directional, they can look in different directions.
- If the directional reference voltage becomes too low, then a directional stage is blocked.
- A range of Relay Characteristic Angles (RCA) is available to cover different kinds of power systems earthing.
- A range of Relay Operate Angles (ROA) is available that allow the limit of operation boundary to be less than 180 degrees (setting roa < ±90 degrees), thereby providing an additional discrimination capability.

29.3 Measuring principles

29.3.1 Non-directional earth fault protection

The earth fault time-current protection (TEF) is based on the zero sequence current. The zero sequence current can be:

- calculated within RET 521 (as Izs), from a set of 3 line (terminal) currents which are fed to RET 521 or is
- fed to RET 521 as a single current (as 3*Izs) which can be a direct sum of 3 line (terminal) currents, or is supplied as a single current by a special core balance summation current transformer. Alternatively, current from the power transformer neutral connection can be used.

Being based on the zero sequence currents, the TEF protection can be made comparatively very sensitive. However, if the zero sequence current is a sum of the phase (line, terminal) currents, then there is a danger of temporary false zero sequence currents, due to an eventual saturation of one or more cts. Even in case of heavy phase-to-phase faults not involving earth such false zero sequence currents may appear. In RET 521 this danger is partly diminished by the TEF protection being based on the fundamental frequency zero sequence currents. In this respect, a TEF fed with a zero sequence current (3*Izs) from a special core balance current transformer is the best solution.

The lowset stage, or the highset stage, or both, can be stabilized by the second harmonic contents in the “instantaneous” zero sequence current. This feature is necessary to prevent misoperations of the TEF protection due to inrush in case of earthed power transformer windings.

The second harmonic restrain is enabled independently for lowset and highset stage with the settings 2harLow respective 2harHigh. Both stages use the same setting I2/I1ratio, in order to detect if the second-to-first harmonic ratio exceeds this value. The output, I2BLK, is set to 1 if the ratio is above the limit.

There are two different time characteristics available in the TEF protection:

1 Definite delay

2 Inverse delay

- normal inverse (NI)
- very inverse (VI)
- extremely inverse (EI)
- longtime inverse (LI)
- Logarithmic i.e. RXIDG (LOG)

There are five different inverse curve types. The lowset stage of the TEF protection can use all delay types, while the highset stage only uses the definite delay type.

IEC 255-4 defines the inverse time characteristic with the following equation:

$$t_{op} = \frac{(k \times T_b)}{\left(\frac{I}{I_{set}}\right)^p - 1}$$

where:

t_{op} operate time

I actual value of the measured earth fault current

I_{set} set current limit

p exponent, power

k time multiplier

T_b base time

Table 84: Inverse curves range for time multiplier k, and setting step of k.

Inverse curve	TEF setting Time characteristic for TEFx	T_b (s)	p	k	k - step
normal inverse	NI	0.14	0.02	0.05 - 1.10	0.01
very inverse	VI	13.5	1	0.05 - 1.10	0.01
extremely inverse	EI	80	2	0.05 - 1.10	0.01
longtime inverse	LI	120	1	0.05 - 1.10	0.01

Normal Inverse curves

The Normal Inverse delay is defined by the following expression:

$$t_{op} = \frac{(k \times 0.14)}{\left(\frac{I}{I_{set}}\right)^{0.02} - 1}$$

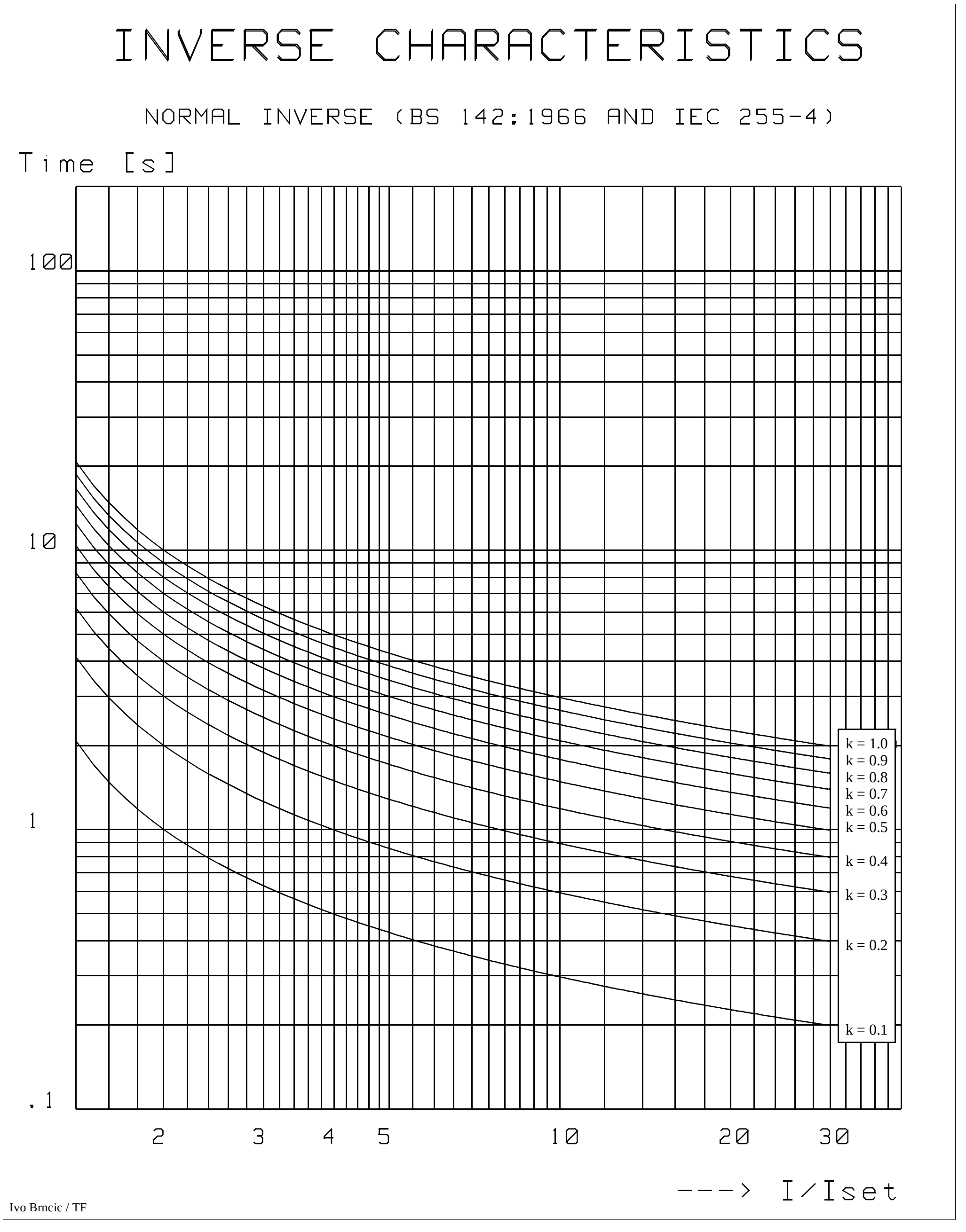


Fig. 77 Normal Inverse curves

Very Inverse curves

Fig. 78 shows the Very Inverse curves, defined by:

$$t_{op} = \frac{(k \times 13.5)}{\left(\frac{I}{I_{set}}\right)^{1} - 1}$$

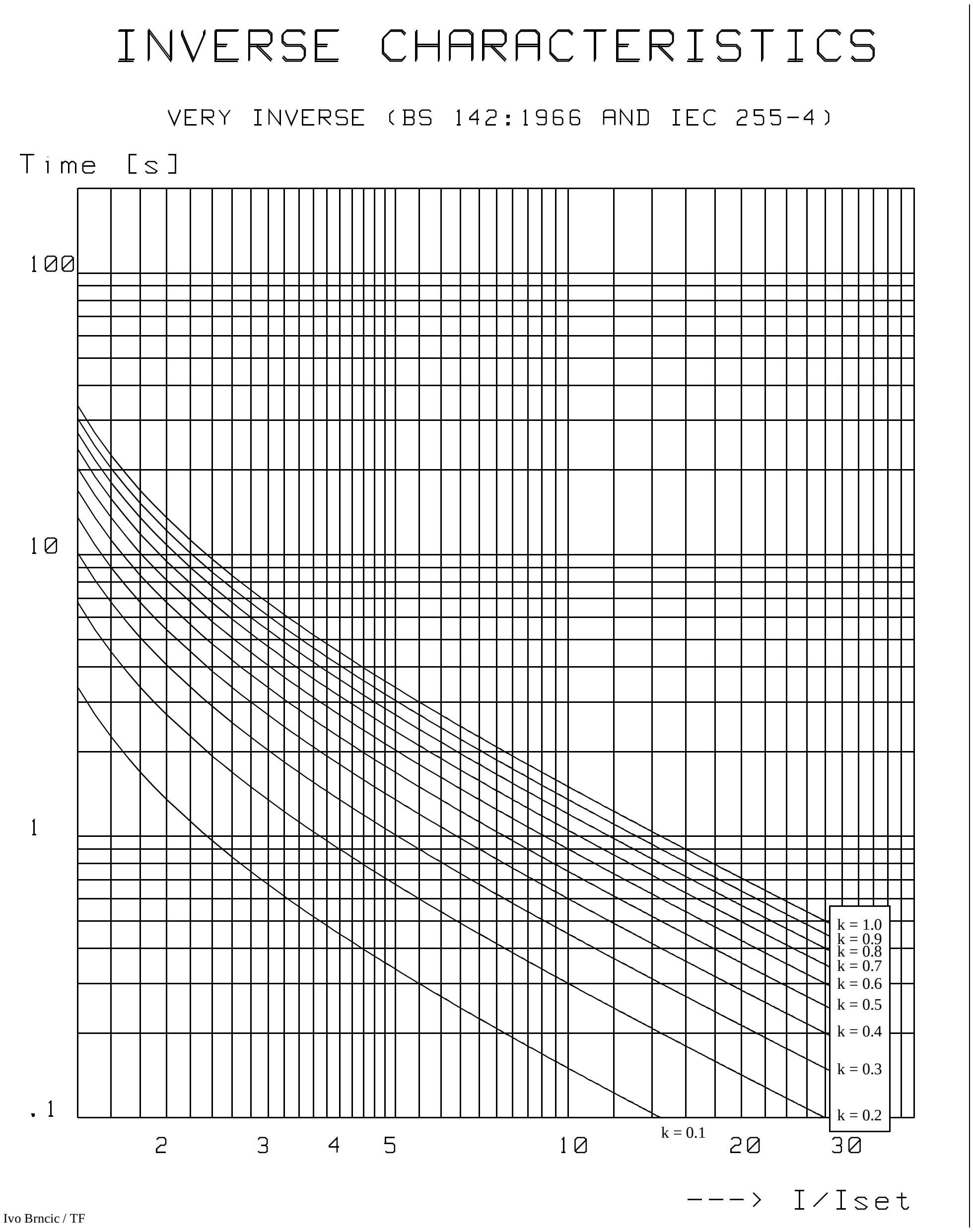


Fig. 78 Very Inverse curves

Extremely Inverse characteristics

Fig. 79 shows the Extremely Inverse curves, defined by:

$$t_{op} = \frac{(k \times 80)}{\left(\frac{I}{I_{set}}\right)^2 - 1}$$

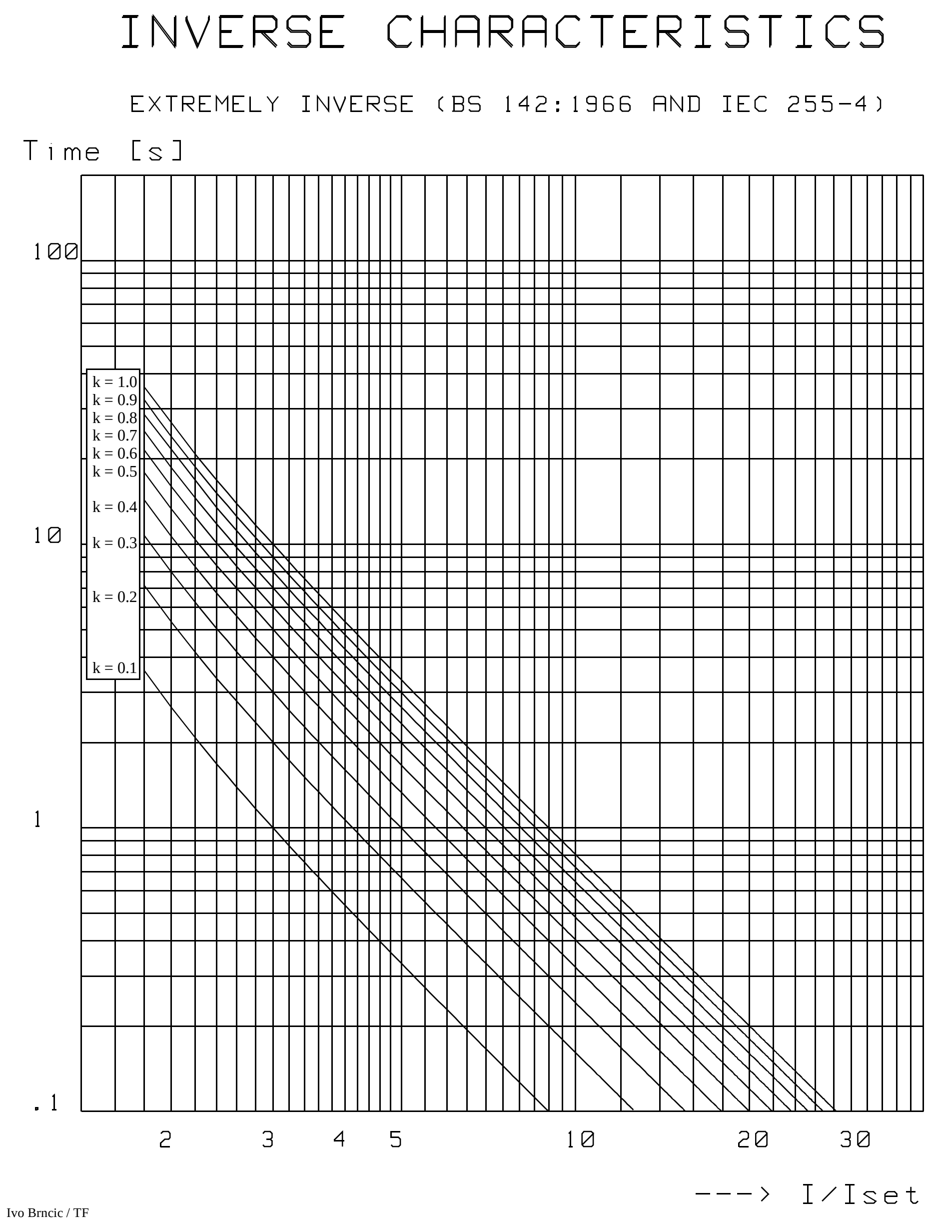


Fig. 79 Extremely Inverse curves

Longtime Inverse characteristics

Fig. 80 shows the Longtime Inverse curves, defined by:

$$t_{op} = \frac{k \times 120}{(I/I_{set}) - 1}$$

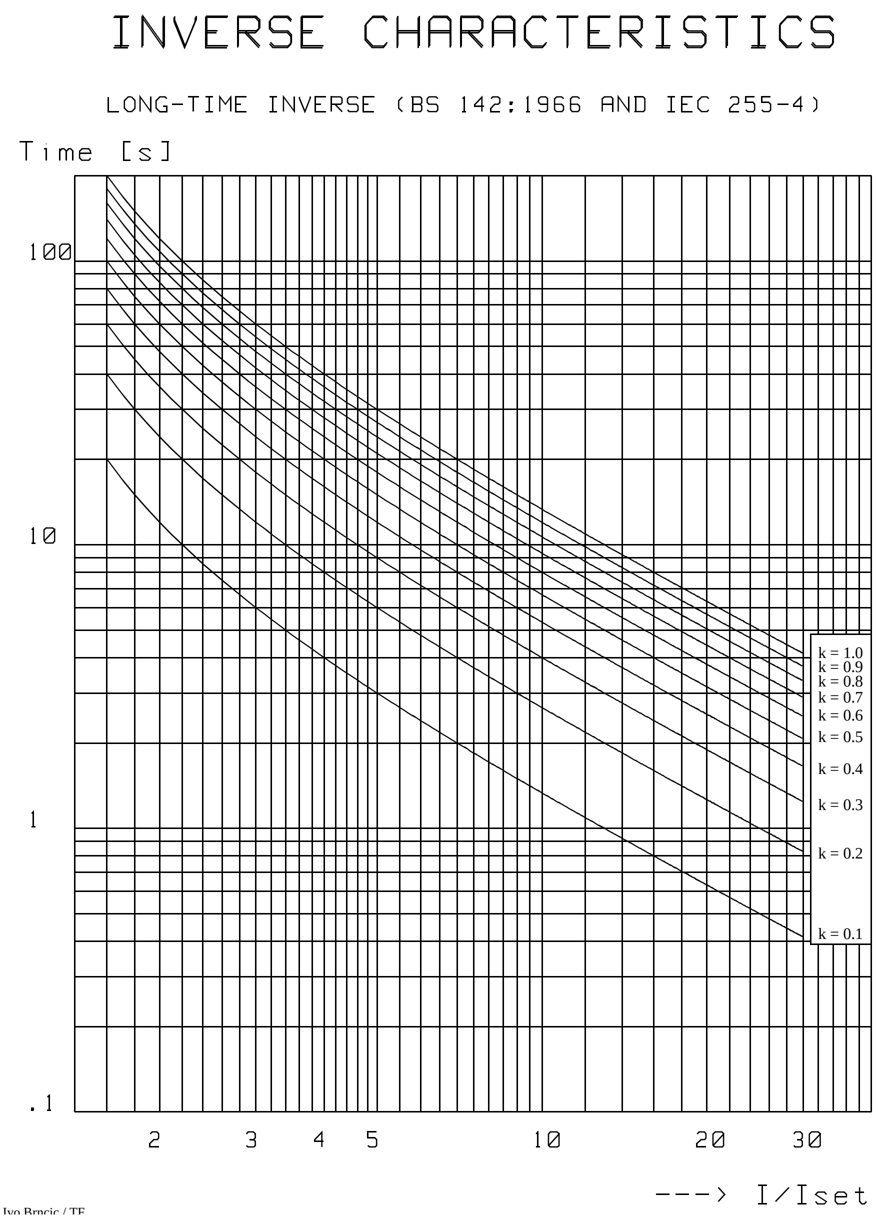


Fig. 80 Long-time Inverse curves

29.3.2 Logarithmic Curves

Fig. 81 shows Logaritmic (RXIDG) curves, defined by:

$$t_{op} = 5,8 - 1,35 \times ln(I/I_{set}/k)$$

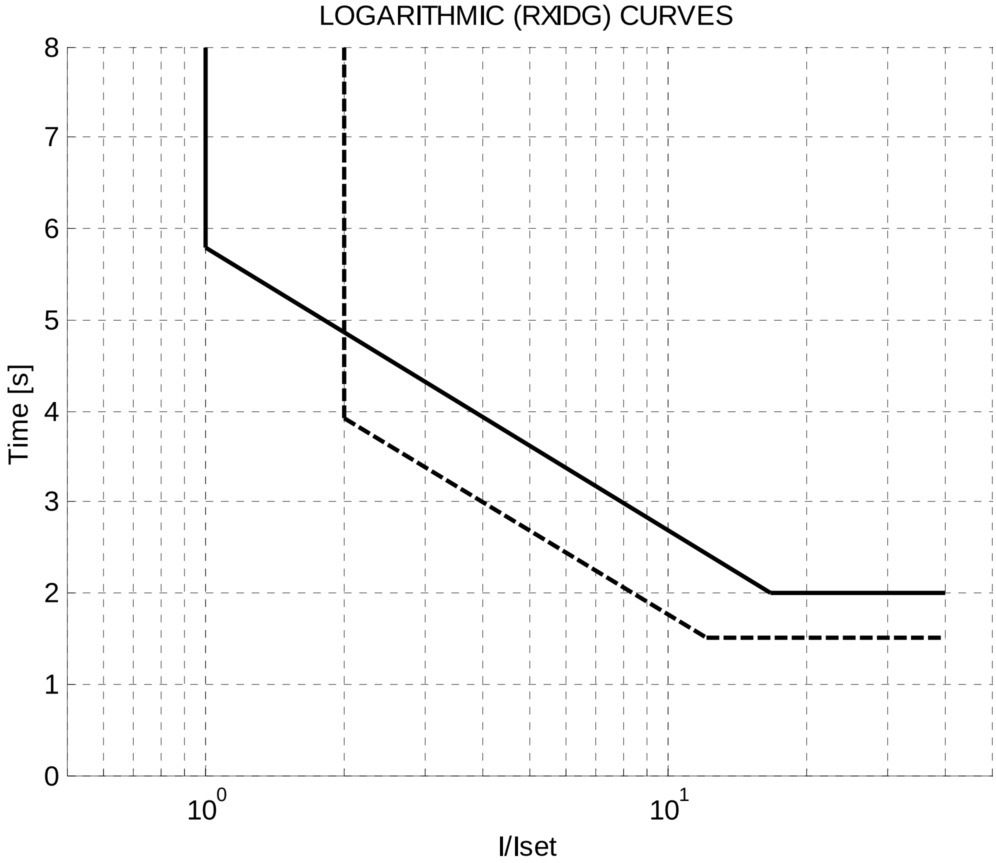


Fig. 81 Logarithmic curves (RXIDG)

29.3.3 Calculation of IEC inverse delays

Expression for the operate time t_{op}, can be re-written as:

$$t_{op} \times \left(\left(\frac{I}{I_{set}} \right)^{p} - 1 \right) = k \times T_b = const$$

This expression tells that the operate time t_{op} is a function of the mean value of the variable $[(I/I_{set})^p - 1]$, which in turn is a function of the variable I/I_{set}. For p = 1 this variable is equal to the relative earth fault current above the set value I_{set}. The operate time t_{op} will be inversely proportional to the mean value of variable $[(I/I_{set})^p - 1]$ up to the point of trip. In an integral form, the decision to trip is made at time *t* when:

$$\int_0^t \left(\left(\frac{I(t)}{I_{set}} \right)^{p} - 1 \right) \times dt \geq k \times T_b = const$$

A numerical relay must instead make a sum:

$$\Delta t \times \sum_{j=1}^{n} \left(\left(\frac{I(j)}{I_{set}} \right)^{p} - 1 \right) \geq k \times T_b = const$$

where:

j = 1	a fault has been detected, for the first time it is $I / I_{set} > 1$
Δt	time interval between two successive executions of earth fault function. If the earth fault protection is executed with an execution frequency f_{ex} = 50 Hz, then Δt = 1/50 s = 20 ms.
n	an integer, the number of the earth fault function execution intervals Δt from the inception of the fault to the point of time when the above condition for trip is fulfilled and trip command issued.
I(j)	value of the fault current at point in time j.

29.3.4 Directional control of the earth fault time current protection (TEF)

The zero-sequence (residual) quantities (Uzs, -Izs) are applied to the directional element of the TEF protection. The TEF protection discriminates between earth faults on different sides (relative to the TEF protection location) by checking the phase position of the measured zero sequence current (-Izs) with respect to the measured zero sequence voltage (Uzs).

The magnitude of the zero sequence voltage can vary over a wide range. The zero sequence voltage has its maximum at the fault location and decreases in magnitude as the system earthing point is approached. The level of this voltage at the TEF protection location is a function of the ratio of the zero sequence impedance between the earth fault and the TEF protection, and the zero sequence impedance between the TEF protection and the system earthing point beyond the TEF protection. Thus the zero sequence voltage will be a maximum if the fault is at the TEF location and will decrease as the earth fault is moved away from the relay. The kind of power system earthing affects the zero sequence impedance greatly. In stations with large, solidly grounded transformers, the zero sequence voltage will be very low at the relay.

The lowset and the highset stages of the TEF protection are totally independent of each other with regard to direction (i.e. position of the fault). They can be either directional or non-directional, independent of each other. If both are directional, they can look in opposite directions.

The RCA has a more clear physical ground in case of the TEF compared to overcurrent protection TOC.

For example, if a power system is earthed through a resistance, it will be the dominant zero sequence impedance, and the relay may have RCA = 0 degrees. In case of solidly earthed power systems, the zero sequence impedance will be predominantly reactive and the zero sequence impedance angle may be as much as 70 to 87 degrees.

The TEF protection can look into the power transformer (Reverse), or into the power system, away from the power transformer (Forward). This definition is valid for all power transformer sides. Two examples are given by means of Fig. 82 and Fig. 83.

Fig. 82 illustrates the case where TEF protection is set to look into the power transformer, i.e. Reverse. Because of Yd connection of power transformer, TEF protection cannot feel faults beyond the power transformer, i.e. on d-side. As far as the earth faults in the Y winding of the power transformer are concerned, TEF only measures the contribution to the total earth fault current which flows from the power system to the earth fault. If the circuit breaker on Y side is open, the TEF protection cannot possibly detect such a fault.

Fig. 83 illustrates the case where the TEF protection is set to look from the power transformer and into the power system left of the TEFprotection point (Forward). Then, earth faults left of the TEF protection position can be detected. The TEF protection only measures the contribution to the total earth fault current which flows from power transformer to earth fault.

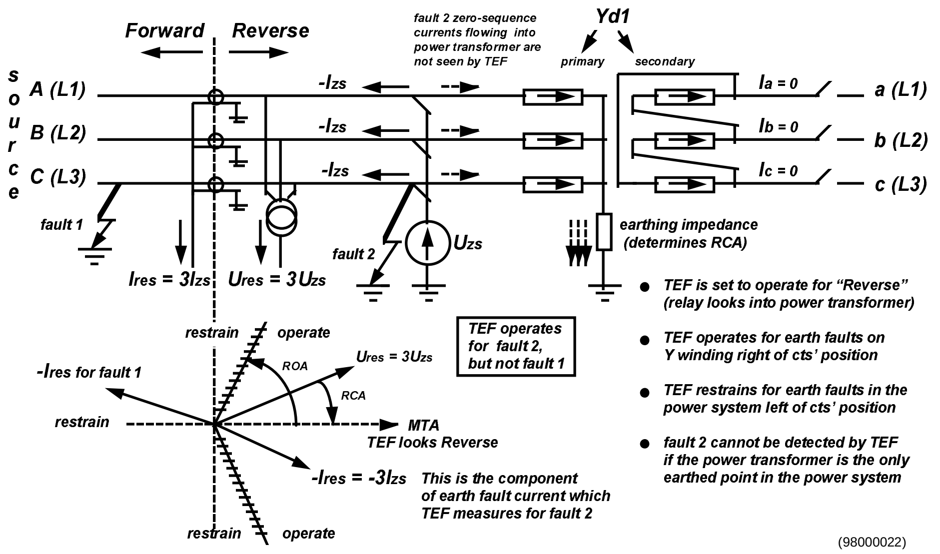


Fig. 82 TEF direction set to Reverse

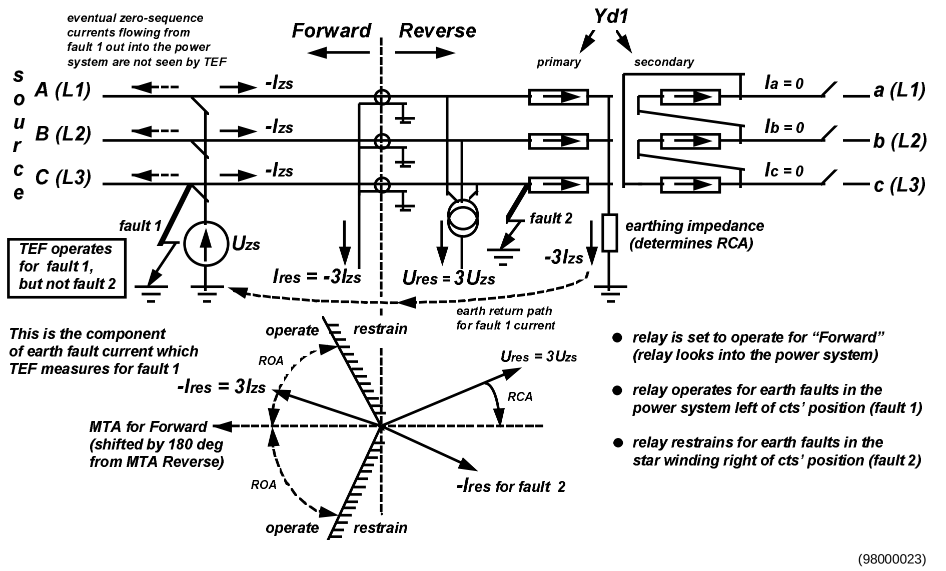


Fig. 83 TEF direction set to Forward

29.4 Logic diagram

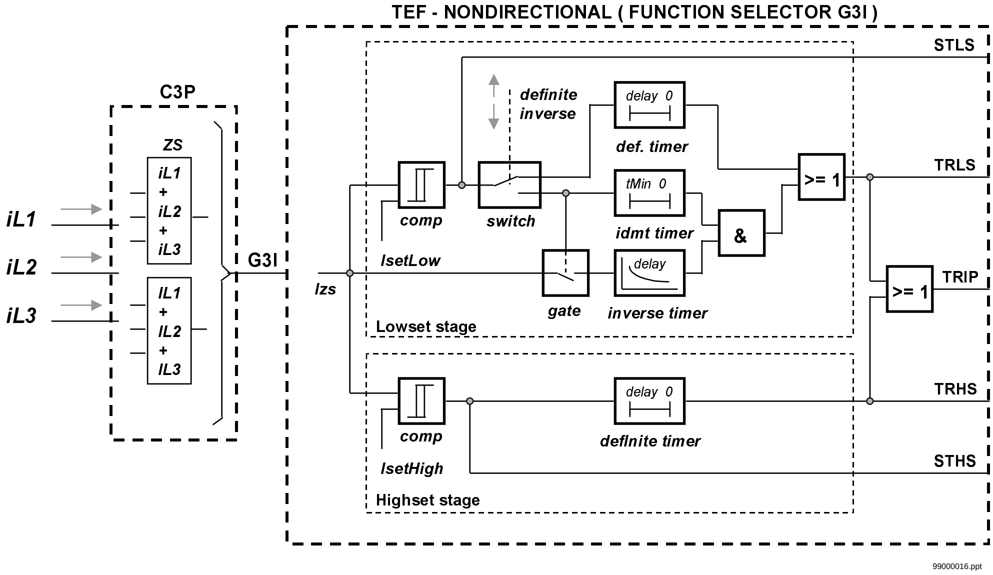


Fig. 84 *Earth fault protection operating on residual current which is supplied by current processing function block C3P.*

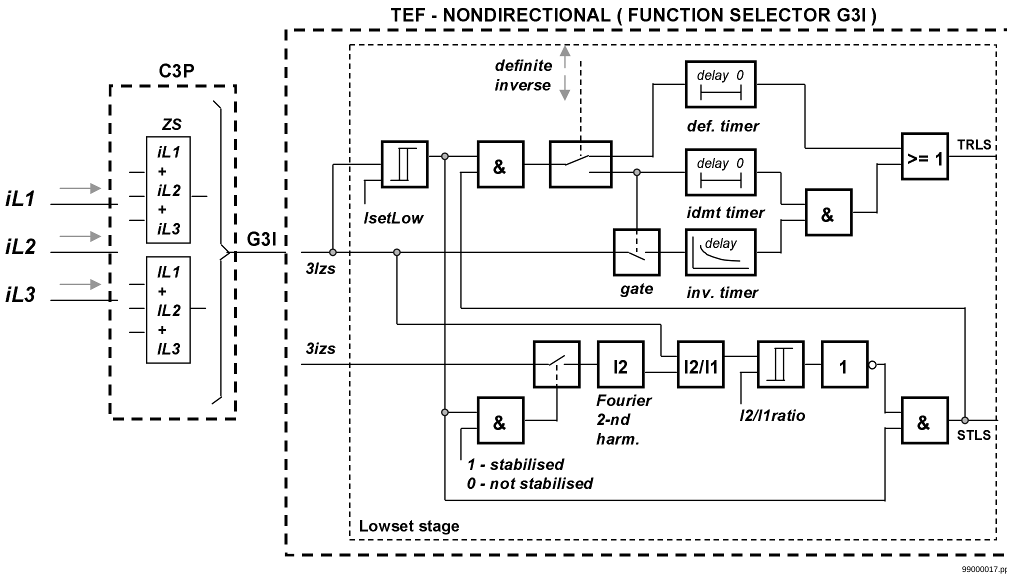


Fig. 85 *Earth fault protection operating on residual current which is supplied by current processing function block C3P. The 2-nd harmonic restrain option applied. Only lowset stage shown.*

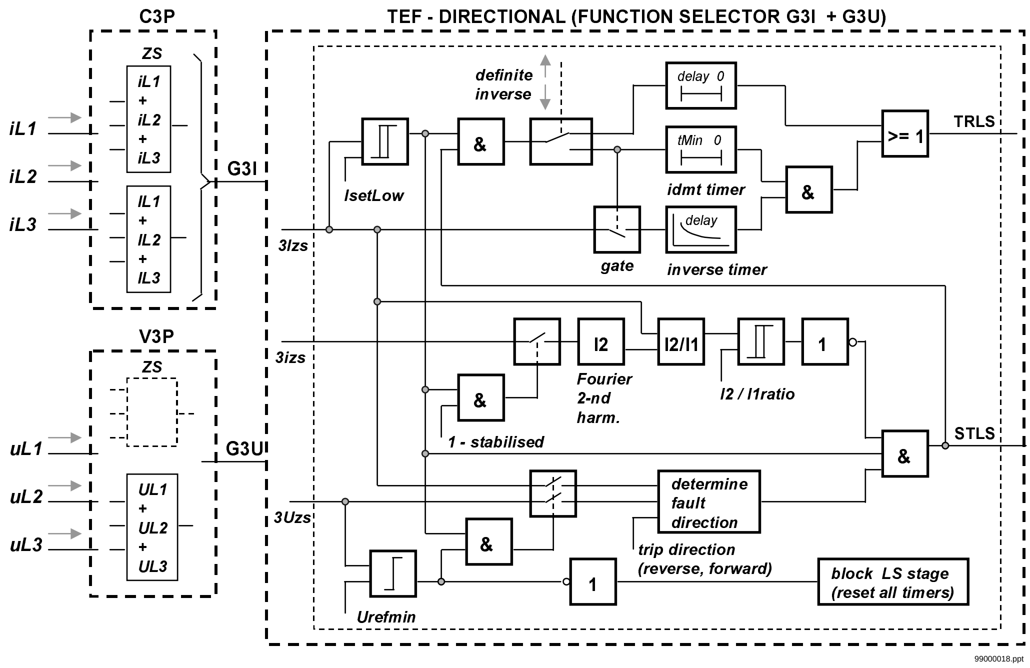
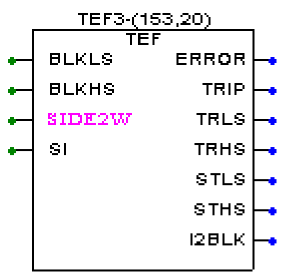


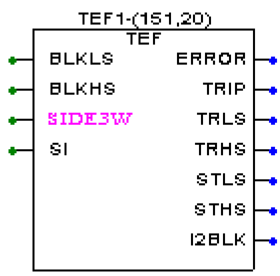
Fig. 86 *Directional earth fault protection operating on residual current which is supplied by current processing function block C3P, and residual voltage supplied by voltage processing function block V3P. The 2-nd harmonic restrain option applied. Only lowset stage shown.*

29.5 Function block

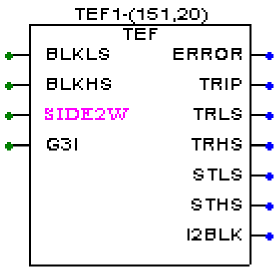
For Earth Fault Time Current Protection, TEF, there are six different kinds of the function block. (Left: 2-winding power transformers, right: 3-winding transformers.)

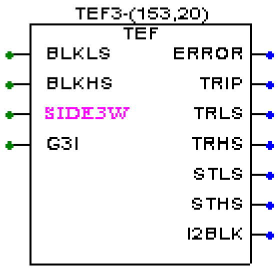
Nondirectional TEF (Function Selector SI). Residual or neutral current must be connected to the analog input SI



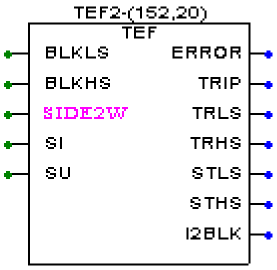


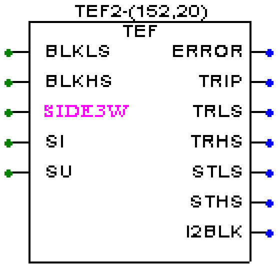
Nondirectional TEF (Function Selector G3I). Residual current calculated internally.



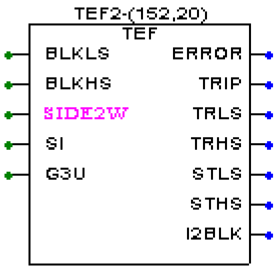


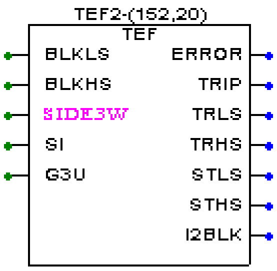
Directional TEF (Function Selector SI + SU). Residual current and residual voltage connected to analog inputs SI and SU.



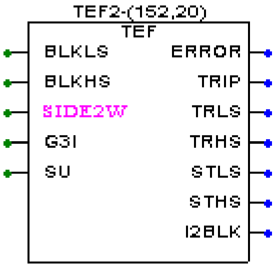


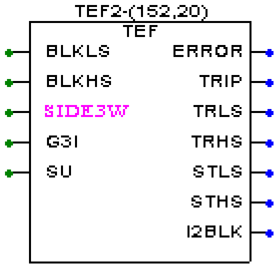
Directional TEF (Function Selector SI + G3U). Residual current connected to analog input, residual voltage calculated internally.



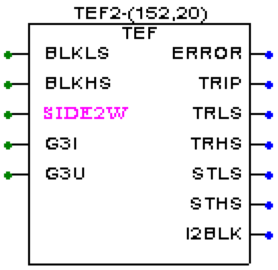


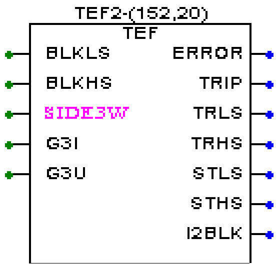
Directional TEF (Function Selector G3I+SU. Residual current calculated internally, residual voltage connected to analogue input SU.





Directional TEF (Function Selector G3I + G3U). Residual current and residual voltage calculated internally.





29.6 Input and output signals

Table 85: TEF function block: input signals (x = 1, 2, 3)

In:	Description:
TEFx:BLKLS	External block lowset, TEFx
TEFx:BLKHS	External block highset, TEFx
TEFx:SIDE2W or TEFx:SIDE3W	Transformer side, TEFx
TEFx:SI	Single phase current, TEFx
TEFx:G3I	Three phase current group, TEFx
TEFx:SU	Single voltage, TEFx
TEFx:G3U	Three phase voltage group, TEFx

Table 86: TEF function block: output signals (x = 1, 2, 3)

Out:	Description:	Type	Range
TEFx:ERROR	General TEFx function error	Int	0 - 1
TEFx:TRIP	Common trip TEFx	Int	0 - 1
TEFx:TRLS	Trip lowset, TEFx	Int	0 - 1
TEFx:TRHS	Trip highset, TEFx	Int	0 - 1
TEFx:STLS	Start lowset, TEFx	Int	0 - 1
TEFx:STHS	Start highset, TEFx	Int	0 - 1
TEFx:I2BLK	Second harmonic block, TEFx	Int	0 - 1

29.7 Setting parameters and ranges

Table 87: TEF- settings, their ranges and descriptions

Parameter:	Range:	Description:
Operation	0=Off, 1=On	Operation Earth Fault Time Current Protection, Off/On
IrUserDef	1 - 99999	Rated current for user defined side, in A
IsetLow	3 - 500	Start current, lowset, in % of Ir
IsetHigh	20 - 2000	Start current, highset, in % of Ir
IStart	1.0 - 4.0	Start current limit factor for logarithmic delay (LOG)
CurveType	0 - 5	Time characteristic for TEFx, DEF/NI/VI/EI/LI/LOG
tDefLow	0.00 - 300.00	Definite delay lowset, in sec.
tMin	0.05 - 1.00	Minimum operating time, in sec.
tLog	0.03 - 10.00	Minimum operating time for LOG delay, in sec.
tDefHigh	0.00 - 300.00	Definite delay highset, in sec.
k	0.05 - 1.10	Time multiple for inverse time function
2harLow	0=Off, 1=On	2nd Harmonic stabilization lowset, Off/On
2harHigh	0=Off, 1=On	2nd Harmonic stabilization highset, Off/On
I2/I1ratio	10 - 25	Second to first harmonic ratio, in %
BlockLow	0=Off, 1=On	Block lowset, Off/On
BlockHigh	0=Off, 1=On	Block highset, Off/On
DirectionLow	0=NonDir, 1=Forward, 2=Reverse	Direction for trip, lowset, NonDir/Forward/Reverse
DirectionHigh	0=NonDir, 1=Forward, 2=Reverse	Direction for trip, highset, NonDir/Forward/Reverse
rca	0 - 90	Relay Characteristic Angle, in deg.
roa	60 - 90	Relay Operate Angle, in deg.
UrUserDef	1.0 - 999.9	Rated voltage for user defined side, in kV

29.8 Service report values

Table 88:

Parameter:	Range:	Step:	Description:
3Io	0.0 - 99999.9	0.1	EarthFault current in A
3Uo	0.0 - 999.9	0.1	EarthFault voltage in kV (Only valid for directional earth fault protection)

30 Single/three-phase time overvoltage protection (TOV)

30.1 Summary of application

Overvoltage protection is applied on power system elements, such as generators, transformers, motors and power lines in order to prevent excessive voltages that could damage the insulation and/or cause insulation breakdown.

Overvoltage can refer either to a high speed transient or to a sustained condition at power system frequency.

Transient voltages originate largely in the transmission system because of switching and atmospheric disturbances. Such surges are dealt with by different kind of equipment, such as for example diverters, connected to incoming lines or station busbars.

The TOV is concerned with power frequency overvoltages. Power frequency overvoltages may be caused by the following contingencies:

1 Defective operation of a voltage regulator,

2 Operation under manual voltage control,

3 Sudden loss of load on power lines or generators,

4 Phase-to-earth faults in power systems earthed via a high impedance, or unearthed.

30.2 Summary of function

- Single voltage, or three-phase voltage versions available.
- If single voltage input version is chosen, a phase-to-earth, or a phase-to-phase, or residual, or neutral point voltage can be applied as an input.
- If three-phase voltage version is chosen, three phase-to-earth voltages are applied as inputs. In this case each voltage can be processed separately, or the residual voltage calculated and processed. If three phase-to-earth voltages are processed separately then it is possible to require that only one voltage above the limit is enough for a trip, or that all three voltages must exceed the limit.
- The TOV protection has a reset ratio of 0.99.
- The TOV protection is an overvoltage protection with a lowset and a highset stage.
- The lowset stage has optionally a voltage independent (definite - DEF), or voltage dependent delay (Very Inverse - VI). An inverse delay can not be shorter than the tMin which is settable.
- The highset stage can only have a voltage independent (definite - DEF) delay.

30.3 Measuring principles

30.3.1 General on TOV protection

The overvoltage protection TOV is fed with voltages of the fundamental power system frequency, all higher harmonic components are efficiently suppressed by the Fourier filters. This is particularly important for zero sequence voltage based overvoltage protections, which should not feel any third harmonic components, which are of the zero sequence.

Overvoltage protection TOV may optionally have the following inputs:

1 Three phase-to-earth (i.e. line, terminal) voltages; TOV of the type G3U, or G3URES. A TOV function block of one of these two types is fed by a V3P module.

2 One single voltage; TOV of the type SU. This single voltage can be optionally:

2.1 One phase-to-phase voltage, or one phase-to-earth voltage.

2.2 Neutral point voltage, (i.e. voltage of the transformer neutral point to earth).

2.3 Residual voltage (from the open delta winding of the line voltage transformer).

A protection such as under 1. (Function Selector G3U) operates on separate values of the three phase-to-earth voltages (L1, L2, L3), or the residual (i.e. 3*Uzs) voltage (Function Selector G3URES), which is constructed internally within RET 521 from the three phase-to-earth voltages. The choice is made by the Function Selector (FS) in CAP tool.

The TOV protections with inputs as under 2. (of the type SU) are identical, it is only the input voltage which is different. A protection such as under 2.1 operates on the magnitude of the phase-to-phase or phase-to-earth input voltage. A protection as under 2.2 have the neutral point voltage as input. A protection as under 2.3 is fed by the residual voltage from an open-delta line voltage transformer.

Protections which operate on the zero sequence type voltage, (residual or neutral point voltage) have usually the voltage settings which are below the rated voltage, while the protections which operate on phase-to-earth, or a phase-to-phase voltage have usually settings above the respective rated voltage value. In case of TOV, type SU, it is important to remember:

- The rated voltage is the phase-to-phase voltage, specified for the protected object (e.g. power transformer phase-to-phase rated voltage). All limits must be expressed in % of this voltage. For example, if a TOV, fed by three phase-to-earth voltages shall operate at 120% of rated phase-to-earth voltage, than it must be set UsetLow = 1.2 * (1 / sqrt(3)) * 100 = 1.2 * 0.577 *100 = 69.28 = 69%.
- TOV has a lowset stage, and a highset stage. A user sets the respective voltage limits for both stages. The highset stage should be set to a value which is higher than the lowset limit.

The relevant voltages are always compared to the set limits. If excessive voltage has been noticed, a start signal (STLS or STHS on the TOV function block output set to 1) is placed for that voltage. If the set limit has been exceeded, then a hysteresis is applied (that is a reset ratio, which is 0.99), so that the measured voltage must be lower than 0.99 times the limit if the start signal is to be removed. Removal of a start signal may cause a timer to be reset, and a trip request signal to be removed. i.e. reset to 0.

Both the lowset stage, and the highset stage, can be blocked by an external block signal, (external to TOV protection, and external to RET 521) independently from each other. Besides, both the lowset stage, and/or the highset stage, can be blocked (disabled, deactivated) by a setting parameter, BlockLow, BlockHigh.

The delays are organized so that:

- The lowset stage has optionally definite, or voltage dependent (Very Inverse VI) delay,
- The highset stage has only a definite, a voltage-independent delay.

30.3.2 The three phase overvoltage protection

If three phase-to-earth voltages are fed to TOV function block (Function Selector: 2 = G3U), then all three voltages are separately compared to the lowset stage limit. If excessive voltage has been noticed in a phase, a start signal (STLS) is placed by the lowset stage for the affected phase.

If a definite (voltage-independent) delay has been set by the user for the lowset stage, (setting: DelayType = DEF), then the following happens. The lowset stage has two definite timers. The first timer starts if at least one voltage has exceeded its limit, and the second timer starts if all voltages have exceeded the lowset limit. The first timer is reset to 0 if no start signals exist, while the second timer is reset to 0 unless all three start signals are placed. When the first timer reaches the set definite delay, a trip request signal is placed by TOV function block, which is called TRLSONE. If the other timer reaches the definite delay, a trip request is placed by TOV function block, which is called TRLSALL.

If the lowset stage uses Very Inverse delay (setting: DelayType = VI, see Fig. 58), then the following happens. The lowset stage has two “inverse” timers. The first timer starts if at least one voltage has exceeded its limit, and the second timer starts if all voltages have exceeded the lowset limit. The highest of the voltages is taken as a basis for the calculation of each inverse delay by both timers. One can make sure that the inverse delay can never be shorter than the so called Inverse Delay Minimum Time (IDMT) by setting an appropriate value for the respective setting, which is called tMin. No trip request can be issued by the lowset stage unless both the tMin, and the inverse delay have elapsed. When the first inverse timer passes the inverse delay, a trip request signal is placed, which is called TRLSONE. When the other inverse timer passes the set inverse delay, a trip request is placed, which is called TRLSALL.

The same procedure as described above, is used by the highset stage, with the difference, that the highset stage only has definite (voltage-independent) delay.

The TOV (Function Selector: 2 = G3U) places a common trip request, if either of stages has issued its respective trip requests. There are two common signals. The first is called TRIPONE, and the second TRIPALL. A user may choose which one of the two common trip requests suits best in a particular application.

30.3.3 The residual voltage protection

If three phase-to-earth voltages are fed to TOV (Function Selector: 3 = G3URES), then the residual voltage is constructed from the three phase-to-earth phasors within a function block V3P, and its magnitude, and phase position, are calculated. This is then read by the TOV function block. The magnitude is then compared to the lowset stage limit. If excessive voltage has been noticed, a start signal (STLS) is placed by the lowset stage.

If a definite (voltage-independent) delay has been set (setting: CurveType = DEF) by the user for the lowset stage, then as long as the start signal is set, the lowset delay timer will continue to measure time. A trip request signal (TRLS) is issued by the lowset stage when the definite delay has been exceeded.

If the lowset stage uses Very Inverse delay (setting: CurveType = VI), then the residual voltage is taken as a basis for the calculation of the inverse delay. One can make sure that the inverse delay never will be shorter than the IDMT by setting an appropriate value for the respective setting, which is tMin. A trip request signal (TRLS) will be issued by the lowset stage when both the IDMT, and the inverse delay have been exceeded.

The residual voltage is also compared to the highset stage limit. If excessive voltage has been observed, a start signal (STHS) is placed by the highset stage. The highset stage has only a definite, that is voltage-independent delay. As long as the start signal is set, the highset delay timer will continue to measure time. A trip request signal (TRHS) will be issued by the highset stage when the definite delay has been exceeded.

The TOV function block places a common trip request (TRIP), if either of the stages has issued its respective trip requests.

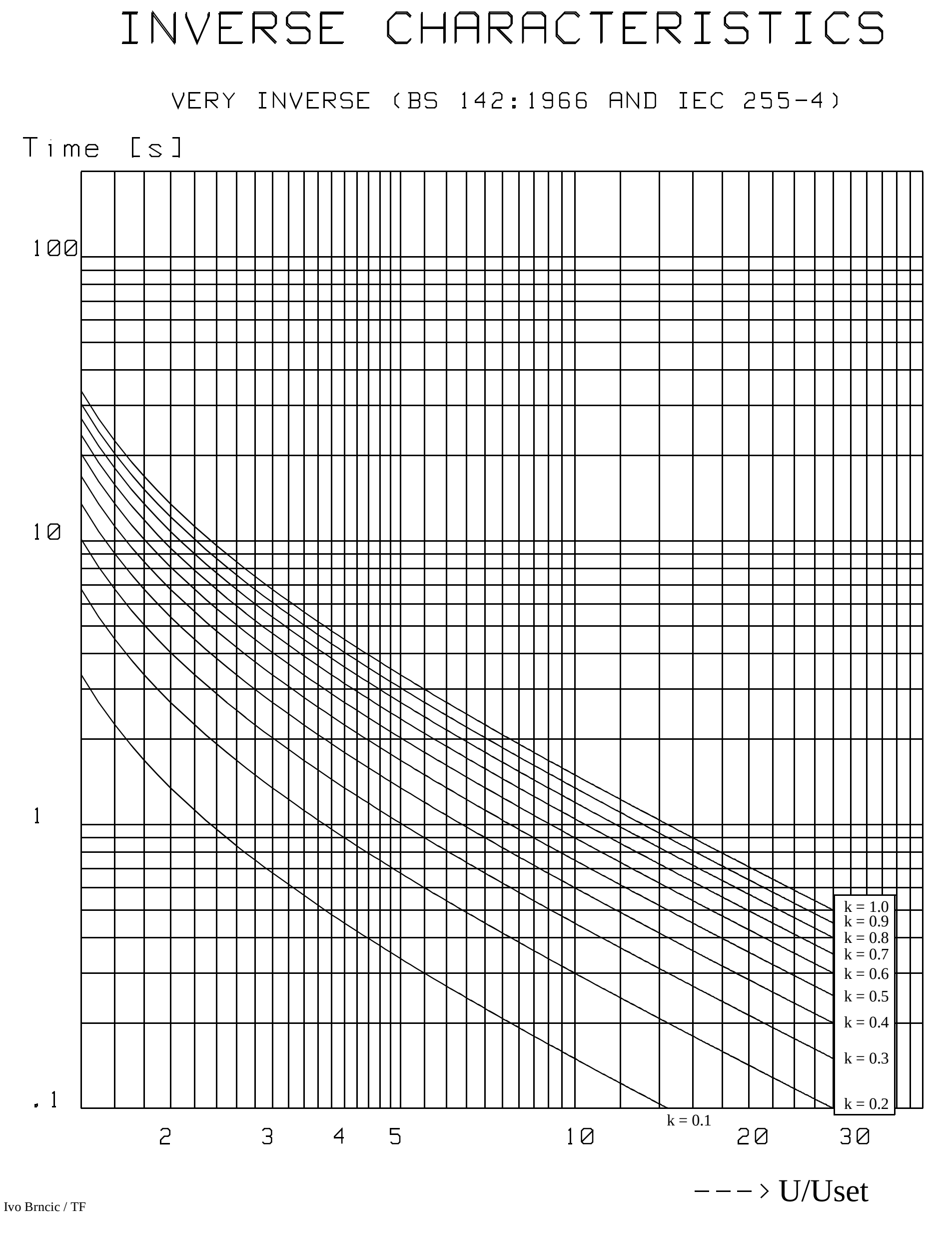
30.3.4 Single input overvoltage protection

This protection (chosen by setting Function Selector: 1 = SU) can be used either as a:

- phase-to-phase (or phase-to-earth) overvoltage protection, or
- residual voltage protection, (input voltage from open delta voltage transformer),
- neutral voltage protection, (input voltage from a neutral point voltage transformer)

Very Inverse curves

Fig. 87 shows the very inverse curves, defined by:



$$t_{op} = \frac{(k \times 13.5)}{\left(\frac{U}{U_{set}}\right) - 1}$$

Fig. 87 Very Inverse curves

30.4 Logic diagrams

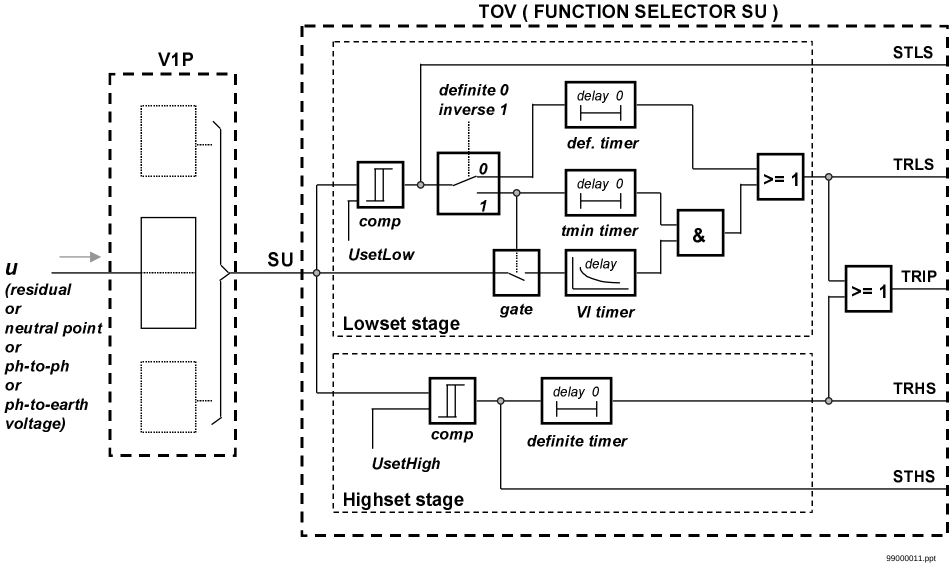


Fig. 88 A single voltage input version of TOV (Function Selector = SU)

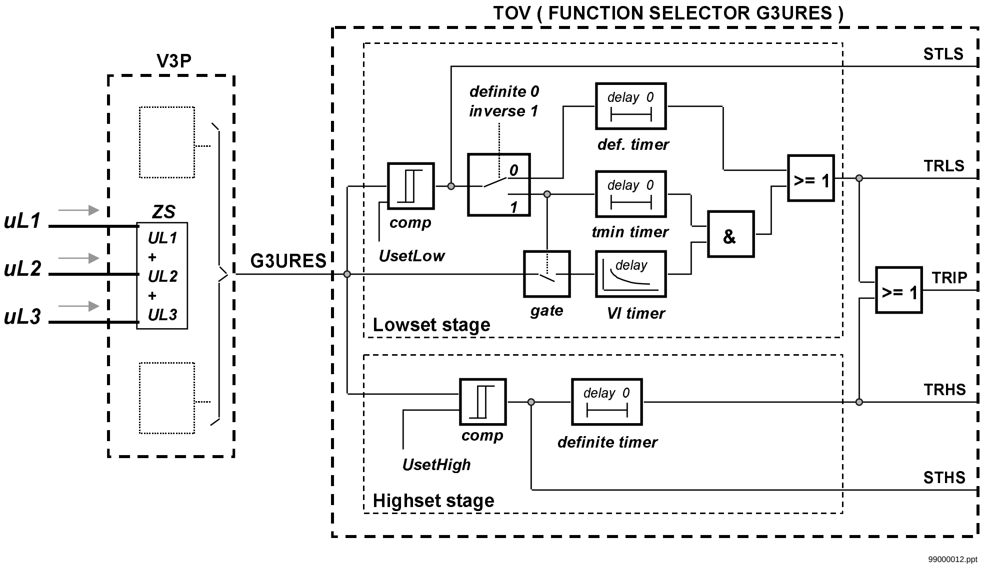


Fig. 89 A three phase voltage input version of TOV (Function Selector = G3URES)

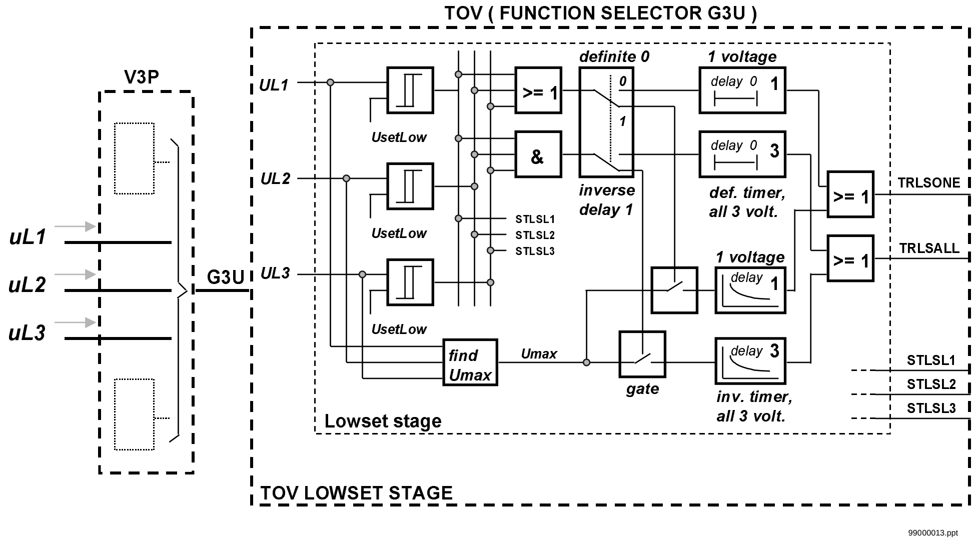
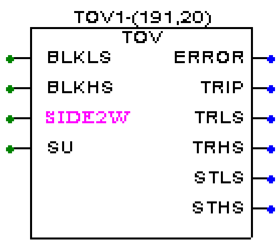


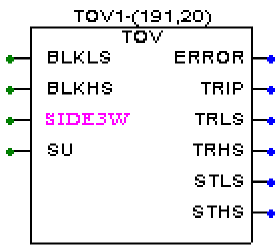
Fig. 90 A three phase voltage input version of TOV (Function Selector = G3U)

30.5 Function block

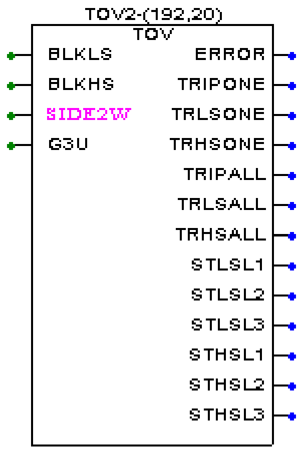
There are three versions available for the TOV protection function block: 2-winding power transformer blocks on the left side, 3-winding transformer on the right side. Altogether 6 instances of TOV protection blocks are available in RET 521.

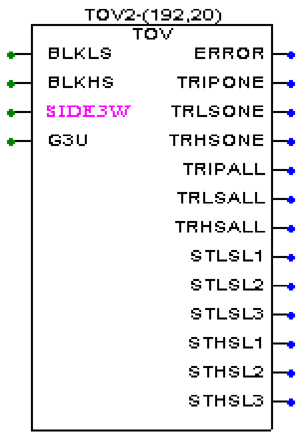
Function Selector SU. A single phase, phase-to-phase, residual or neutral point voltage input.



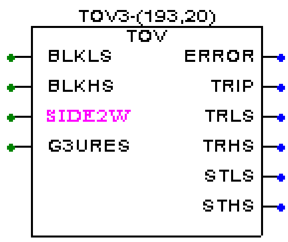


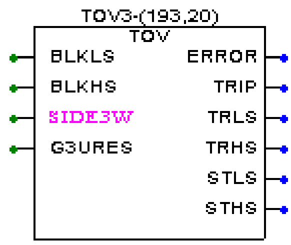
Function Selector G3U. Three phase-to-earth voltage input.





Function Selector G3URES. Residual voltage calculated internally from three phase-to-earth voltages.





30.6 Input and output signals

Table 89: TOV function block: input signals (x = 1, 2, 3)

In:	Description:
TOVx:BLKLS	External block lowset, TOVx
TOVx:BLKLS	External block highset, TOVx
TOVx:SIDE2W or TOVx:SIDE3W	Transformer side, TOVx
TOVx:SU or TOVx:G3U or TOVx:G3URES	Single voltage, TOVx Three phase voltage group, TOVx Residual voltage, TOVx

Table 90: TOV function block: output signals (x = 1, 2, 3)

Out:	Description:	Type	Range
TOVx:ERROR	General TOVx function error	Int	0 - 1
TOVx:TRIP	Common trip, TOVx	Int	0 - 1
TOVx:TRLS	Trip lowset, TOVx	Int	0 - 1
TOVx:TRHS	Trip highset, TOVx	Int	0 - 1
TOVx:TRIPONE	Common trip at least one phase, TOVx	Int	0 - 1
TOVx:TRLSONE	Trip lowset at least one phase, TOVx	Int	0 - 1
TOVx:TRHSONE	Trip highset at least one phase, TOVx	Int	0 - 1
TOVx:TRIPALL	Common trip in all phases, TOVx	Int	0 - 1
TOVx:TRLSALL	Trip lowset in all phases, TOVx	Int	0 - 1
TOVx:TRHSALL	Trip highset in all phases, TOVx	Int	0 - 1
TOVx:STLS	Start lowset, TOVx	Int	0 - 1
TOVx:STHS	Start highset, TOVx	Int	0 - 1
TOVx:STLSL1	Start lowset, phase 1, TOVx	Int	0 - 1
TOVx:STLSL2	Start lowset, phase 2, TOVx	Int	0 - 1
TOVx:STLSL3	Start lowset, phase 3, TOVx	Int	0 - 1
TOVx:STHSL1	Start highset, phase 1, TOVx	Int	0 - 1
TOVx:STHSL2	Start highset, phase 2, TOVx	Int	0 - 1
TOVx:STHSL3	Start highset, phase 3, TOVx	Int	0 - 1

30.7 Setting parameters and ranges

Table 91: TOV settings, their ranges and descriptions

Parameter:	Range:	Description:
Operation	0=Off, 1=On	Operation Time Overvoltage Protection, Off/On
UsetLow	5.0 - 200.0	Start voltage, lowset stage, in % of Ur
UsetHigh	5.0 - 200.0	Start voltage, highset stage, in % of Ur
CurveType	0=DEF, 1=VI	Time characteristic for TOVx, DEF/VI
tDefLow	0.00 - 300.00	Definite delay lowset stage, in seconds
tMin	0.05 - 1.00	Minimum operating time, in seconds
tDefHigh	0.00 - 300.00	Definite delay highset stage, in seconds
k	0.05 - 1.10	Time multiplier for inverse time function
BlockLow	0=Off, 1=On	Block lowset stage, Off/On
BlockHigh	0=Off, 1=On	Block highset stage, Off/On

30.8 Service report values

Table 92: TOV service report

Parameter:	Range:	Step:	Description:
Umax	0.0 - 999.9	0.1	Highest of measured voltages, in kV

31 Single/three-phase time undervoltage protection (TUV)

31.1 Summary of application

Undervoltage protection is applied on power system elements, such as generators, transformers, motors and power lines in order to detect low voltage profiles that could be a sign that abnormalities, such as short circuits, have happened. An undervoltage protection may also be used to produce a signal that an apparatus, such as a power transformer, is not energized.

The undervoltage protection is often applied in systems with motor drives. Sometimes, the undervoltage protection is used to control, or restrain, the overcurrent protections. It is also possible to have it the other way around, where a trip signal from undervoltage protection is logically combined with some overcurrent protection trip request.

Undervoltages may be caused by the following contingencies:

1 Defective operation of a voltage regulator (usually a symmetrical phenomenon),

2 Operation under manual voltage control, (usually a symmetrical phenomenon),

3 Overloads (usually a symmetrical phenomenon),

4 Short circuits (usually an unsymmetrical phenomenon).

31.2 Summary of function

Features of the undervoltage protection TUV:

- The TUV protection issues start and trip signals when the voltage is below certain levels.
- Single voltage, or three-phase voltage versions are available.,
- If TUV protection is a single-voltage input version, a phase-to-earth voltage, or a phase-to-phase voltage, can be applied as an input.

- If TUV protection is a three-phase voltage version, three phase-to-earth voltages are applied as inputs. In this case each voltage can be processed separately. If voltages are processed separately then it is possible to require that only one voltage below the limit is enough for a trip, or that all three voltages are below the limit.
- The TUV protection has a reset ratio of 1.01.
- The TUV protection is an undervoltage protection with a lowset and a highset stage.
- The lowset and highset stage have only a voltage-independent (definite) delay.

31.3 Measuring principles

31.3.1 General

There are two versions of the TUV protection function block available in the CAP configuration tool. A suitable version can be chosen by means of the Function Selector in the CAP configuration tool. Depending on which variant has been selected (Function Selector SU or G3U), the function input can be either a phase-to-earth or phase-to-phase voltage, or a three phase phase-to-earth voltage.

When either a single voltage is below a set level, or all voltages are below level, a trip delay timer starts. Trip signal is set by the TUV protection function block when elapsed time exceeds the set time delay. Both variants have two independent stages, lowset and highset.

31.3.2 Application of function inputs

31.3.2.1 External block inputs, BLKLS and BLKHS

Blocking of the lowset and highset stages is possible by using the inputs BLKLS, external block lowset, and BLKHS, external block lowset. It is possible to block lowset and highset stage independently. The blocking prohibits the outputs from being set, but the TUV protection service value Umin is still displayed.

It is also possible to block TUV protection in test mode by setting BlockTUV = On from the HMI, or by altering the settings BlockLow or BlockHigh.

Note: While blocked, the TUV protection internal operation will continue and service values will be updated. Enabling or disabling of test mode or the settings BlockLow and BlockHigh will reset the TUVprotection, i.e. all timers and service values will be reset.

31.3.2.2 Analog inputs with Function Selector SU

The input SU can be connected to:

- SU output on a V1Px function block, or
- SU1, or SU2 or SU3 outputs of a V3Px function block.

31.3.2.3 Analog inputs with Function Selector G3U

The input G3U can be connected to:

- G3U output of a V3Px function block.

31.3.3 Application of function outputs

31.3.3.1 Outputs with Function Selector SU

Start signals, STLS and STHS

The signal STLS, start lowset stage, is set when the measured voltage, becomes less than UsetLow, the start voltage lowset in % of Urated.

STLS is reset when the measured voltage is above 101% of UsetLow. The signal STHS, start highset stage, operates in the same way, with the exception that the measured voltage is compared to UsetHigh, the start voltage of the highset stage.

Trip signals, TRIP, TRLS and TRHS

The signal TRIP, common trip, is set if TRLS, trip lowset stage, or TRHS, trip highset-stage is set.

The signal TRLS is set when the time since the start signal STLS was set, gets longer than the definite delay of the lowset stage, tDefLow. The signal TRHS operates in the same way, with the exception that time is compared to tDefHigh, the definite delay of the highset stage.

Resetting STLS also resets the TRIP timer.

Error signal, ERROR

The signal ERROR, general TUV protection function error, is set if:

- parameter SIDE2W or SIDE3W is set to No, or
- some error in the configuration of the analog input SU.

31.3.3.2 Outputs with Function Selector G3U

With the Function Selector set for three phase inputs, each phase will have its individual, private, output signals. To simplify descriptions, where applicable, signals will be described only once, having the designation n, to mark the possible individual set of signals. The n can be a integer between 1 and 3.

Start signals, STLSLn and STHSLn

The signal STLSn, start lowset stage is set the lowest of all three input voltages gets lower than UsetLow, the start voltage of the lowset stage, in % of Urated.

STLSn is reset when the lowest of all three input voltages is above 101% of UsetLow. The signal STHS, start highset, operates in the same way, with the exception that the lowest of all three input voltages is compared to UsetHighn, the start voltage of the highset stage.

Trip signals, TRIPONE, TRLSONE and TRHSONE

The signal TRIPONE, common trip at least one phase, is set if TRLSONE or TRHSONE is set.

The signal TRLSONE, trip lowset one phase, is set when the time elapsed since any of the start signals STLS1, STLS2 or STLS3 was set, gets longer than tDefLow, the definite delay lowset. The signal TRHSONE operates in the same way, with the exception that the elapsed time is compared to tDefHigh, the definite delay highset.

Resetting any of STLS1, STLS2 or STLS3 also resets the TRIPONE timer.

Trip signals, TRIPALL, TRLSALL and TRHSALL

The signal TRIPALL, common trip all phases, is set if TRLSALL or TRHSALL is set.

The signal TRLSALL, trip lowset all phases, is set when the time elapsed since all of the start signals STLS1, STLS2 or STLS3 was set, gets longer than tDefLow, the definite delay lowset. The signal TRHSALL operates in the same way, with the exception that the elapsed time is compared to tDefHigh, the definite delay highset.

Resetting any of STLS1, STLS2 or STLS3 also resets the TRIPALL timer.

Error signal, ERROR

The signal ERROR, general TUV protection function error, is set if:

- parameter SIDE2W or SIDE3W is set to No, or
- some error in the configuration of the analog input G3U.

31.3.4 Settings

The setting Operation, Operation Time Undervoltage Protection, switches the TUV Off or On. No outputs or service values are shown when Operation = Off.

The setting UsetLow, the start voltage lowset in % of Ur, is used to set the desired voltage level for lowset. The setting is multiplied by the rated voltage for the selected side for the power transformer.

Example: The parameter SIDE2W = Pri, and the rated voltage of the primary side (phase-to-phase!) is 100.0 kV. The setting UsetLow is set to 50%. The set level is 50% * 100.0 = 50.0 kV.

The setting UsetHigh, start voltage lowset in % of Ur, is similar to the setting UsetLow.

The setting tDefLow, definite delay lowset in sec, defines the desired delay from start lowset to trip lowset.

The setting tDefHigh, definite delay highset in sec, is similar to tDefLow.

The setting BlockLow, block lowset, block lowset stage. No output signals from lowset stage is set.

The setting BlockHigh, is similar to BlockLow.

31.3.4.1 Parameter settings in CAP tool

A TUV protection function block has one parameter setting in the CAP tool, SIDE2W when the terminal is ordered for use with a two winding power transformer, or SIDE3W, when ordered for use with a three winding power transformer.

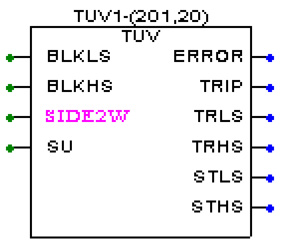
31.3.5 Application of TUV protection function service value

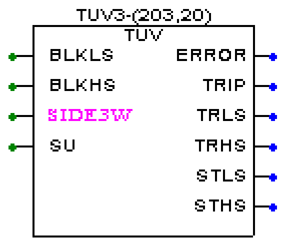
The service value Umin, shows, depending of the function selector, the measured voltage in kV (Function Selector set to SU), or the lowest of all measured voltages in kV (Function Selector set to G3U).

31.4 Function block

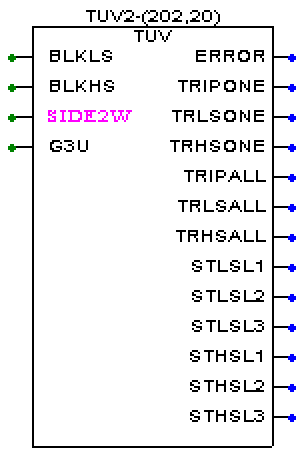
There are two versions available for the TUV protection function block: 2-winding power transformer TUV blocks shown on the left, 3-winding transformer on the right side. Altogether 3 instances of TUV protection blocks are available in RET 521.

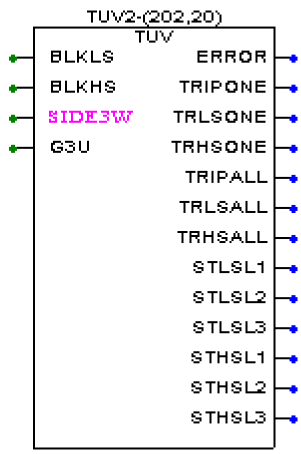
Function Selector SU. A single voltage input version. Single-phase or phase-to-phase voltage measurement.





Function Selector G3U. Three phase-to-earth voltage input.





31.5 Input and output signals

Table 93: TUV function block: input signals (x = 1, 2, 3)

In:	Description:
TUVx:BLKLS	External block lowset, TUVx
TUVx:BLKHS	External block highset, TUVx
TUVx:SIDE2W or TUVx:SIDE3W	Transformer side, TUVx
TUVx:SU or TUVx:G3U	Single voltage, TUVx Three phase voltage group, TUVx

Table 94: TUV (Function Selector = SU) function block:ouput signals (x = 1, 2, 3)

Out:	Description:
TUVx:ERROR	General TUVx function error
TUVx:TRIP	Common trip, TUVx
TUVx:TRLS	Trip lowset, TUVx
TUVx:TRHS	Trip highset, TUVx
TUVx:STLS	Start lowset, TUVx
TUVx:STHS	Start highset, TUVx

Table 95: TUV (Function Selector = G3U) function block:ouput signals (x = 1, 2, 3)

Out:	Description:
TUVx:ERROR	General TUVx function error
TUVx:TRLS	Trip lowset, TUVx
TUVx:TRHS	Trip highset, TUVx
TUVx:TRIPONE	Common trip at least one phase, TUVx
TUVx:TRLSONE	Trip lowset at least one phase, TUVx
TUVx:TRHSONE	Trip highset at least one phase, TUVx
TUVx:TRIPALL	Common trip in all phases, TUVx
TUVx:TRLSALL	Trip lowset in all phases, TUVx
TUVx:TRHSALL	Trip highset in all phases, TUVx
TUVx:STLS	Start lowset, TUVx
TUVx:STHS	Start highset, TUVx
TUVx:STLSL1	Start lowset, phase 1, TUVx

Table 95: TUV (Function Selector = G3U) function block:ouput signals (x = 1, 2, 3)

TUVx:STLSL2	Start lowset, phase 2, TUVx
TUVx:STLSL3	Start lowset, phase 3, TUVx
TUVx:STHSL1	Start highset, phase 1, TUVx
TUVx:STHSL2	Start highset, phase 2, TUVx
TUVx:STHSL3	Start highset, phase 3, TUVx

31.6 Setting parameters and ranges

Table 96: TUV settings, their ranges and descriptions

Parameter:	Range	Description
Operation	0=Off, 1=On	Operation Time Undervoltage Protection, Off/On
UsetLow	5.0 - 130.0	Start voltage, lowset stage, in % of Ur
UsetHigh	5.0 - 130.0	Start voltage, highset stage, in % of Ur
tDefLow	0.00 - 300.00	Definite delay lowset stage, in sec.
tDefHigh	0.00 - 300.00	Definite delay highset stage, in sec.
BlockLow	0=Off, 1=On	Block lowset stage, Off/On
BlockHigh	0=Off, 1=On	Block highset stage, Off/On

31.7 Service report values

Table 97: TUV protection function service value

Parameter:	Range:	Step:	Description:
Umin	0.0 - 999.9	0.1	Lowest of measured voltages in kV

32 Thermal overload protection (THOL)

32.1 Summary of application

Transformers which can have load currents above permissible continuous currents, are vulnerable to thermal damage to the paper insulation, caused by a winding hot spot temperature. The main purpose for the thermal overload function (THOL) in RET 521 is to prevent such damages, and at the same time better utilize the capacity of the protected transformer.

The THOL function in RET 521 can be used as an alternative or backup to temperature devices mounted on the transformer. It should be noted that this protection calculates the transformer thermal content without any compensations for ambient temperature. There is however a built-in compensation for transformers with forced cooling which can be activated by the cooling equipment via a binary input.

A thermal overload can be caused by situations such as:

1 Overload, i.e. transferring power that exceeds the rating of the unit
2 External fault not cleared fast enough
3 Failure of the cooling system
4 High ambient temperature
5 Other abnormalities such as low frequency, high voltage, current distortion or phase voltage unbalance.

Note: A moderately high winding temperature during long periods of time will result in faster ageing of transformer insulation. High winding temperatures can lead to insulation failure, even when occurring during short time periods.

32.2 Summary of function

Features for the THOL function in RET 521:

- The THOL function uses a heat content model (without ambient temperature measuring input).
- The THOL function issues alarm and trip signals when the heat content is above certain levels.
- A lock-out function insures that the transformer is cooled off properly before it is allowed to be reconnected.
- Functionality for a transformer with extra cooling is provided.
- Supervision of process parameters and output signals is provided.
- Function block representation in CAP tool.

32.3 Measuring principles

32.3.1 General

The function is fed with three phase currents of which the function selects the highest current. The highest current is then used in the heat content calculations. The calculation of the heat content is based on the fact that the temperature in the windings is proportional to the square of the current, and that the temperature increases and decreases exponentially with a certain time constant, see the following equations:

When $\Theta_{stat} > \Theta_n$:

$$\Theta_{n+1} = \Theta_n + (\Theta_{stat} - \Theta_n) \times \left(1 - e^{-\frac{\Delta t}{\tau}}\right)$$

When $\Theta_{stat} < \Theta_n$:

$$\Theta_{n+1} = \Theta_{stat} - (\Theta_{stat} - \Theta_n) \times e^{-\frac{\Delta t}{\tau}}$$

Θ_n	Actual heat content
Θ_{n+1}	New actual heat content
Θ_{stat}	Steady state (final) heat content
Δt	Time step
τ	Time constant

32.3.2 Application of function outputs

Trip signal, TRIP

When the heat content, Θ_n, exceeds the overload level, Θ_{trip}, the function sets the TRIP signal, where Θ_{trip} is defined as the square of Itr (see Setting parameters and ranges). The signal is set during one execution loop (approximate 200ms).

Lock-out signal, LOCKOUT

To insure that the heat content has decreased to an acceptable level before the transformer is allowed to be reconnected, the LOCKOUT signal is set. The setting parameter ResetLockOut defines the heat content level for the LOCKOUT signal to reset.

Alarm signal, ALARM1 and ALARM2

The THOL function gives alarms (in two stages) if the heat content exceeds the levels Alarm1 or Alarm2 (see Setting parameters and ranges). The alarm signals are reset if the heat content falls 2% below the alarm level.

32.3.3 Function service values

Time to trip

The service value TimeToTrip is activated when the steady state heat content, Θ_{stat}, arises above trip level. The status of the TimeToTrip service value is indicated by the service value TimeToTrCalc that shows three different values: NotActive, *>1.3**TimeConst and Active.

NotActive indicates that the steady state heat content level is below Θ_{trip}. TimeToTrip is therefore showing the prediction horizon (650 min).

*>1.3**TimeConst indicates that the steady state heat content level is above Θ_{trip}, but predicted trip time is greater than 1.3 times selected time constant of the object, that is, the TimeToTrip value is still showing the prediction horizon.

Active indicates that the steady state heat content level is above Θ_{trip}, and that trip is estimated within the prediction horizon. At this stage the actual time to trip is continuously shown by the TimeToTrip service value

When $\Theta_{stat} > \Theta_{trip}$:

$$\text{TimeToTrip} = \tau \times \ln \frac{\Theta_{stat} - \Theta_n}{\Theta_{stat} - \Theta_{trip}}$$

Θ_n	Actual heat content
Θ_{trip}	Heat content trip level
Θ_{stat}	Steady state (final) heat content

Time to reset

The service value TimeToReset works very much as the TimeToTrip service value. The difference is that now we calculate the time until the LOCKOUT signal should be reset after a trip has been issued. The service value TimeToRstCalc shows the status of the TimeToReset value.

$$\mathrm{TimeToReset} = \tau \times \ln \frac{\Theta_n}{\Theta_{\mathrm{reset}}}$$

Θ_n	Actual heat content
Θ_{reset}	Heat content lockout reset level

Measured current

The service value Imeasured shows the value of the current which contributes to the heat content level in the transformer. The value shown is the highest of the three phase currents fed to the function.

Actual heat content level

The service value ThermalStatus shows the actual heat content level in percentage of Θ_{trip}.

32.3.4 Application of function inputs

Block input, BLOCK

The THOL function is possible to block, i.e. prohibit the outputs TRIP, LOCKOUT, ALARM1 and ALARM2 from being set. It should be noted that THOL continues the calculations of heat content and updating of service values. Setting the input BLOCK to true has the same meaning as enabling Test mode and setting the parameter Block-THOL=On with one difference: enabling/disabling test mode will reset the THOL function, i.e. force the THOL to restart. Same functionality can be obtained by using the input RESET, see below.

Cooling enabled input, COOLING

In order to get a more flexible application for transformers with forced cooling the THOL function is fitted with the COOLING input. In short, the status of the input decides which base current and time constant the heat content model shall use. The relation between COOLING input status and settings is described in Table 98:. When there is a change between the two modes, the relative heat content in per cent is maintained.

Table 98: Application of input COOLING

Status	Setting parameter
COOLING=0	Ib1, TimeConstant1
COOLING=1	Ib2, TimeConstant2

Reset input, RESET

The THOL function performs integration with long time constants which might cause problems, normally during testing of the function. By setting the RESET input the heat content is reset to its initial value defined by the setting ThetaInit and the LOCKOUT, ALARM1 and ALARM2 output signals are set to zero. The value of ThetaInit is always used for initialization of the heat content level at terminal startup or after saving new settings/configurations.

32.3.5 Application of inputs G3I and SIDE2W/SIDE3W

The THOL function block should usually be connected to the transformer primary side to incorporate all losses in the measured currents.

The SIDE2W input parameter selects the winding on which the THOL function is connected. If THOL is connected to the primary side, select Pri, on secondary side, select Sec. For three winding terminals SIDE3W is shown with the additional alternative Ter, tertiary side.

Connect the G3I input on THOL function block to the G3I output on the C3Px/C3Cx function block that forms e.g. the primary side currents.

When the G3I input has been correctly configured and SIDE2W/SIDE3W=NoSide, THOLs error output, ERROR, is set. Downloading CAP configuration with SIDE2W/SIDE3W=Pri/Sec/Ter solves the problem.

Note: SIDE2W is active only for a two winding terminal and SIDE3W is active only for a three winding terminal.

32.4 Logic diagram

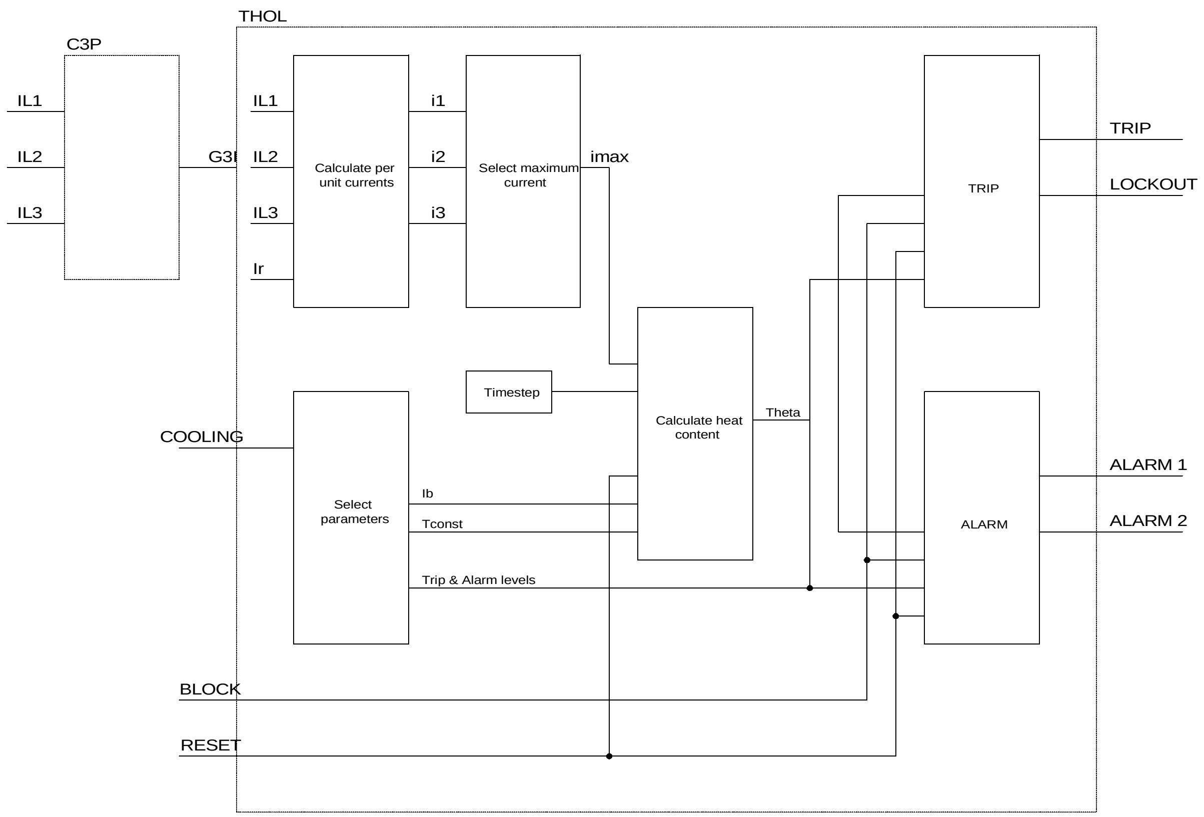
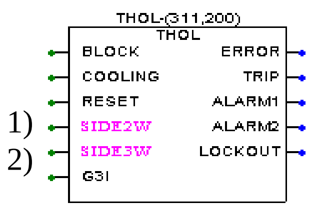


Fig. 91

32.5 Function block



1 Two winding systems only

2 Three winding systems only

32.6 Input and output signals

Table 99:

In:	Description:
THOL:BLOCK	External block, THOL
THOL:COOLING	Transformer extra cooled, changes Ib and time constant, THOL
THOL:RESET	Reset heat content and lockout function, THOL
THOL:SIDE2W	Transformer side, THOL
THOL:G3I	Three phase current group, THOL
THOL:SIDE3W	Transformer side, THOL

Table 100:

Out:	Description:
THOL:ERROR	General THOL function error
THOL:TRIP	Common trip THOL
THOL:ALARM1	First heat content alarm, THOL
THOL:ALARM2	Second heat content alarm, THOL
THOL:LOCKOUT	Transformer locked-out by thermal overload trip, THOL

32.7 Setting parameters and ranges

Table 101:

Parameter:	Range:	Description:
Operation	0 - 1	Operation Thermal Overload Protection, Off/On
Ib1	30 - 250	Normal base current, in % of Ir
Ib2	30 - 250	Base current with true COOLING input signal in % of Ir
Itr	50 - 250	Thermal overload steady state trip current in % of Ibx
ThetaInit	0 - 95	Initial heat content in % of heat content trip
TimeConstant1	1 - 500	Normal time constant, in min, used with Ib1
TimeConstant2	1 - 500	Time constant, in min, used with Ib2
Alarm1	50 - 99	1:st alarm level, in % of heat content trip value
Alarm2	50 - 99	2:nd alarm level, in % of heat content trip value
ResetLockOut	10 - 95	Lockout reset level in % of heat content trip

32.8 Service report values

Table 102:

Parameter:	Range:	Step:	Description:
Imeasured	0 - 250	1	Measured current in % of thermal overload base current
ThermalStatus	0 - 999	1	Thermal status in % of heat content trip level
TimeToReset	1 - 650	1	Time to reset lockout function, in min.
TimeToRstCalc	0 - 2	1	Time to reset lockout calc. NotActive/ >1.3*TimeConst/Active
TimeToTrCalc	0 - 2	1	Time to trip calc. NotActive/>1.3*Time-Const/Active
TimeToTrip	1 - 650	1	Time to trip thermal overload, in min.

33 Overexcitation protection (V/Hz) (OVEX)

33.1 Summary of function

- Importance of the overexcitation protection is growing.
- Modern transformers are more sensitive to overexcitation than earlier types.
- Overexcitation results from excessive voltage and below-normal frequency.
- Overexcitation protection is based on calculation of the relative Volts per Hertz.
- Internal voltage can be calculated if leakage reactance of the winding is known, and relevant currents fed to the OVEX protection function block.
- OVEX protection may be applied on any transformer side, independent of load flow.
- OVEX protection shall not be applied on the power transformer side with an OLTC installed.
- Regarding inputs to OVEX protection, there are two versions available: the first operating on a single phase-to-phase voltage and two terminal currents, and the second, operating on three phase-to-earth voltages and three terminal currents.
- Both OVEX versions are fed with by FRME measured system frequency in Hz.
- Nominal frequency range of OVEX protection is 0.7 - 1.2 rated frequency.
- Voltage must be over 0.7 times rated voltage for OVEX to calculate excitation.
- Actual excitation of the power transformer can be read as a service value.
- There are two types of delay available: the IEEE-, and tailor-made law.

- Each type of delays can be further modified by definite maximum, and definite minimum delays. These extra definite delays are used at very low-, and very high overexcitations.
- Time-to-trip service value is available. It can be useful at lower degrees of overexcitation with longer delays.
- When an overexcitation condition occurs, an alarm signal is issued after an independent definite delay, which is settable.
- The overexcitation is basically a thermal protection. An exponential cooling process has been assumed. The cooling time constant is a setting parameter. If an overexcitation condition returns before the core has cooled down, the delays will be shorter than they would be otherwise.
- A service value called Thermal status is available. It gives information on the thermal status of the iron core in % of the thermal value which causes trip of the protected power transformer. This service value can be useful with smaller degrees of overexcitation, where longer trip times can be expected.

33.2 Measuring principles

33.2.1 General

Although not even mentioned in many books on protective relaying, the importance of overexcitation protection is growing as the power transformers as well as other power system elements today operate most of the time near their designated limits.

Modern design transformers are more sensitive to overexcitation than earlier types. This is a result of the more efficient designs and designs which rely on the improvement in the uniformity of the excitation level of modern systems. Thus, if emergency that includes overexcitation does occur, transformers may be damaged unless corrective action is promptly taken. Transformer manufacturers recommend an overexcitation protection as a part of the transformer protection system.

Overexcitation results from excessive applied voltage, possibly in combination with below-normal frequency. Such condition may occur when a unit is on load, but are more likely to arise when it is on open circuit, or at a loss of load occurrence. Transformers directly connected to generators are in particular danger to experience overexcitation condition. It follows from the fundamental transformer equation:

$$E = 4.44 \times f \times N \times B_{max} \times A$$

that peak flux density Bmax is directly proportional to induced voltage E, and inversely proportional to frequency f, and turns N where they can be changed.

The relative excitation M (relative V/Hz) is therefore:

$$M = relative\left(\frac{V}{Hz}\right) = \frac{E/f}{Ur/fr}$$

Disproportional variations in quantities E and f may give rise to core overfluxing. If the core flux density Bmax increases to a point above saturation level (typically 1.9 Tesla), the flux will no longer be contained within the core only but will extend into other (non-laminated) parts of the power transformer and give rise to eddy current circulations. Overexcitation will be manifested in:

- overheating of the non-laminated metal parts,
- a large increase in magnetizing currents,
- an increase in core and winding temperature,
- an increase in transformer vibration and noise.

Protection against overexcitation is based on calculation of the relative Volts per Hertz (V / Hz) ratio. The action of the protection is usually to initiate a reduction of excitation and, if this should fail, or is not possible, to trip the transformer after a delay which can be from seconds to minutes, typically 5 - 10 seconds.

Overexcitation protection may be of particular concern on directly connected generator unit transformers. Directly connected generator-transformers are subjected to a wide range of frequencies during the acceleration and deceleration of the turbine. In such cases, the overexcitation protection may trip the field breaker during a start-up of a machine, by means of the overexcitation ALARM signal from the transformer terminal. If this is not possible, the power transformer can be disconnected from the source, after a delay, by the TRIP signal.

The IEC 76 - 1 standard requires that transformers shall be capable of operating continuously at 10% above rated voltage at no load, and rated frequency. At no load, the ratio of the actual generator terminal voltage to the actual frequency should not exceed 1.1 times the ratio of transformer rated voltage to the rated frequency on a sustained basis:

$$\frac{E}{f} \leq 1.1 \times \frac{Ur}{fr}$$

or equivalently, with 1.1 * Ur = Emaxcont:

$$\frac{E}{f} \leq \frac{Emaxcont}{fr}$$

where Emaxcont is the maximum continuously allowed voltage at no load, and rated frequency. Emaxcont is an OVEX setting parameter. The setting range is 1.0 pu to 1.5 pu. If the user does not know exactly what to set, then the standard IEC 76 - 1, section 4.4, the default value Emaxcont = 1.10 pu shall be used.

In OVEX protection function the relative excitation M (relative V/Hz) is expressed as:

$$M = relative\left(\frac{V}{Hz}\right) = \frac{E/f}{Ur/fr}$$

It is clear from the above formula that, for an unloaded power transformer, M = 1 for any E and f, where the ratio E / f is equal to Ur / fr. A power transformer is not overexcited as long as the relative excitation is M <= Emaxcont, Emaxcont expressed in pu. The relative overexcitation is thus defined as:

$$overexcitation = M - Emaxcont$$

The overexcitation protection algorithm is fed with an input voltage U which is in general not the induced voltage E from the fundamental transformer equation. For no load condition, these two voltages are the same, but for a loaded power transformer the internally induced voltage E may be lower or higher than the voltage U which is measured and fed to OVEX, depending on the direction of the power flow through the power transformer, the power transformer side where OVEX is applied, and the power transformer leakage reactance of the winding. It is important to specify on the OVEX function block in CAP configuration tool worksheet on which side of the power transformer OVEX is placed.

As an example, at a transformer with a 15% short circuit impedance Xsc, the full load, 0.8 power factor, 105% voltage on the load side, the actual flux level in the transformer core, will not be significantly different from that at the 110% voltage, no load, rated frequency, provided that the short circuit impedance X can be equally divided between the primary and the secondary winding: Xleak = Xleak1 = Xleak2 = Xsc / 2 = 0.075 pu.

OVEX calculates the internal induced voltage E if Xleak (meaning the leakage reactance of the winding where OVEX is placed) is known to the user. The assumption taken for 2-winding power transformers that Xleak = Xsc / 2 is unfortunately most often not true. For a 2-winding power transformer the leakage reactances of the two windings depend on how the windings are placed on the core with respect to each other. In the case of three-winding power transformers the situation is still more complex. If a user has the knowledge on the leakage reactance, then it should applied. If a user has no idea about it, Xleak can be set to zero (0). The OVEX protection will then take the given measured terminal voltage U, as the induced voltage E.

It is assumed that overexcitation is a symmetrical phenomenon, caused by events such as loss of load, etc. It will be observed that a high phase-to-earth voltage does not necessarily mean overexcitation. For example, in an unearthed power system, a single-phase-to-earth fault means high voltages of the “healthy” two phases to earth, but no overexcitation on any winding. The phase-to-phase voltages will remain essentially unchanged. The important voltage is the voltage between the two ends of a winding.

33.2.2 OVEX variants

Two variants of OVEX protection are available: one for the case when only one phase-to-phase voltage is available to RET 521, and another for the case where all three phase-to-earth voltages are available on the side where OVEX is placed. These variants are selected by means of Function Selector in CAP configuration worksheet.

- Function Selector 1 = 2 * SI + SU selects a version of OVEX, operating on a single phase-to-phase voltage, and two terminal currents.
- Function Selector 2 = G3I + G3U selects a version of OVEX which is fed by three phase-to-earth voltages, and three terminal currents.

If one phase-to-phase voltage is available from the side where OVEX protection is applied, then OVEX protection function block with Function Selector 1 shall be set. The particular voltage which is used determines the two currents that must be used. If, for example, voltage Uab is fed to OVEX, then currents Ia, and Ib must be applied, etc. From these two input currents, current Iab = Ia - Ib is calculated internally by the OVEX protection algorithm. The phase-to-phase voltage must be higher than 70% of the rated value, otherwise the OVEX protection algorithm is exited without calculating the excitation. ERROR output is set to 1, and the displayed value of relative excitation V / Hz shows 0.000.

If three phase-to-earth voltages are available from the side where OVEX is placed, then OVEX protection function block with Function Selector 2 shall be used. In this case the positive sequence voltage and the positive sequence current are used by OVEX protection. A check is made within OVEX protection if the positive sequence voltage is higher than 70% rated phase-to-earth voltage; below this value, OVEX is exited immediately, and no excitation is calculated. ERROR output is set to 1, and the displayed value of relative excitation V / Hz shows 0.000.

Both OVEX versions have an “analog” input F, where the power system frequency in Hertz is fed to OVEX. This input must be connected to the F output of the FRME function block. OVEX function is blocked whenever the frequency is outside the range 33.0 Hz - 60.0 Hz (50 Hz system).

- In order to be able to use the OVEX function, the FRME function must be present and in operation.
- OVEX protection function can be placed on any power transformer side, independent from the power flow. The actual side must be specified on OVEX function block in CAP configuration tool worksheet.
- The side with an eventual On-Load-Tap-Changer (OLTC) must not be used.

33.2.3 Operate time of the overexcitation protection.

The operate time of the overexcitation protection is a function of the relative overexcitation. Basically there are two different delay laws available to choose between:

- the so called IEEE law, and
- a tailor-made law.

The so called IEEE law approximates a square law and has been chosen based on analysis of the various transformers' overexcitation capability characteristics. They can match well a transformer core capability.

The **square** law is:

$$t_{op} = \frac{0,18 \times k}{(M - Emaxcont)^2} = \frac{0,18 \times k}{overexcitation^2}$$

where:

M = excitation, mean value in the interval from t = 0 to t = t_{op}

Emaxcont = maximum continuously allowed voltage at no load, and rated freq., in pu.

k = time multiplier setting for inverse time functions, see Fig. 93. Parameter k ("time multiplier setting") selects one delay curve from the famlily of curves.

An analog overexcitation relay would have to evaluate the following integral expression, which means to look for the instant of time t = t_{op} where:

$$\int_0^{t_{op}} (M(t) - Emaxcont)^2 dt \geq 0.18 \times k$$

A digital, numerical relay will instead look for the lowest j (i.e. j = n) where it becomes true that:

$$\Delta t \times \sum_{j=1}^{n} (M(j) - Emaxcont)^2 \geq 0.18 \times k$$

where:

Δt is the time interval between two successive executions of overexcitation function,

M(j) - Emaxcont is the relative excitation at (time j) in excess of the normal (rated) excitation which is given as Ur/fr.

As long as M > Emaxcont (i.e. overexcitation condition), the above sum can only be greater with time, and if the overexcitation persists, the protected transformer will be tripped at j = n.

Inverse delays as per Fig. 93, can be modified (limited) by two special definite delay settings, namely tMax and tMin, see Fig. 92.

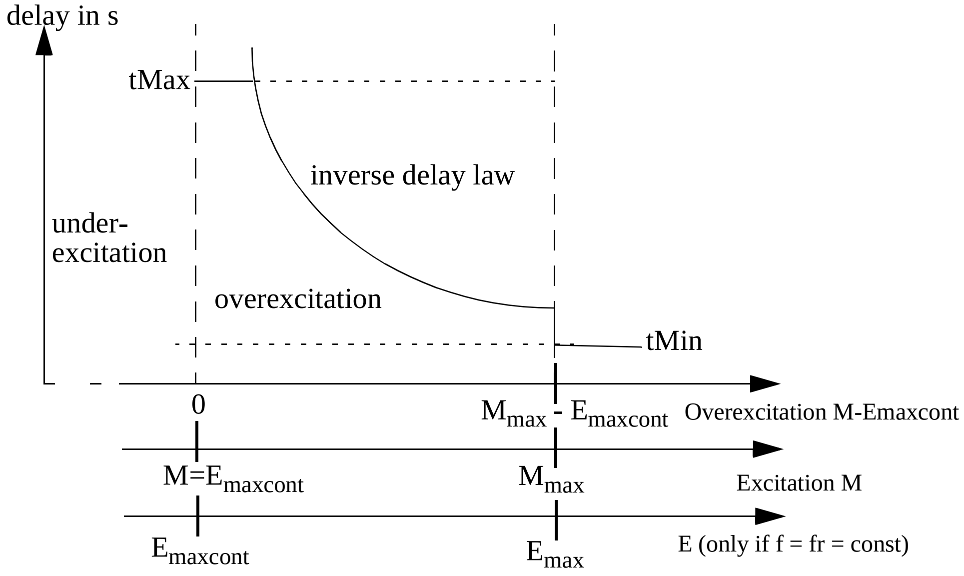


Fig. 92 Restrictions imposed on inverse delays by tMax, and tMin

- a definite maximum time, tMax, can be used to limit the operate time at low degrees of overexcitation. Inverse delays longer than tMax will not be allowed. In case the inverse delay is longer than tMax, OVEX trips after tMax seconds.
- a definite minimum time, tMin, can be used to limit the operate time at high degrees of overexcitation. In case the inverse delay is shorter than tMin, OVEX function trips after tMin seconds. Also, the inverse delay law is no more valid beyond excitation Mmax. Beyond Mmax (beyond overexcitation Mmax - Emaxcont), the delay will always be tMin, no matter what overexcitation.

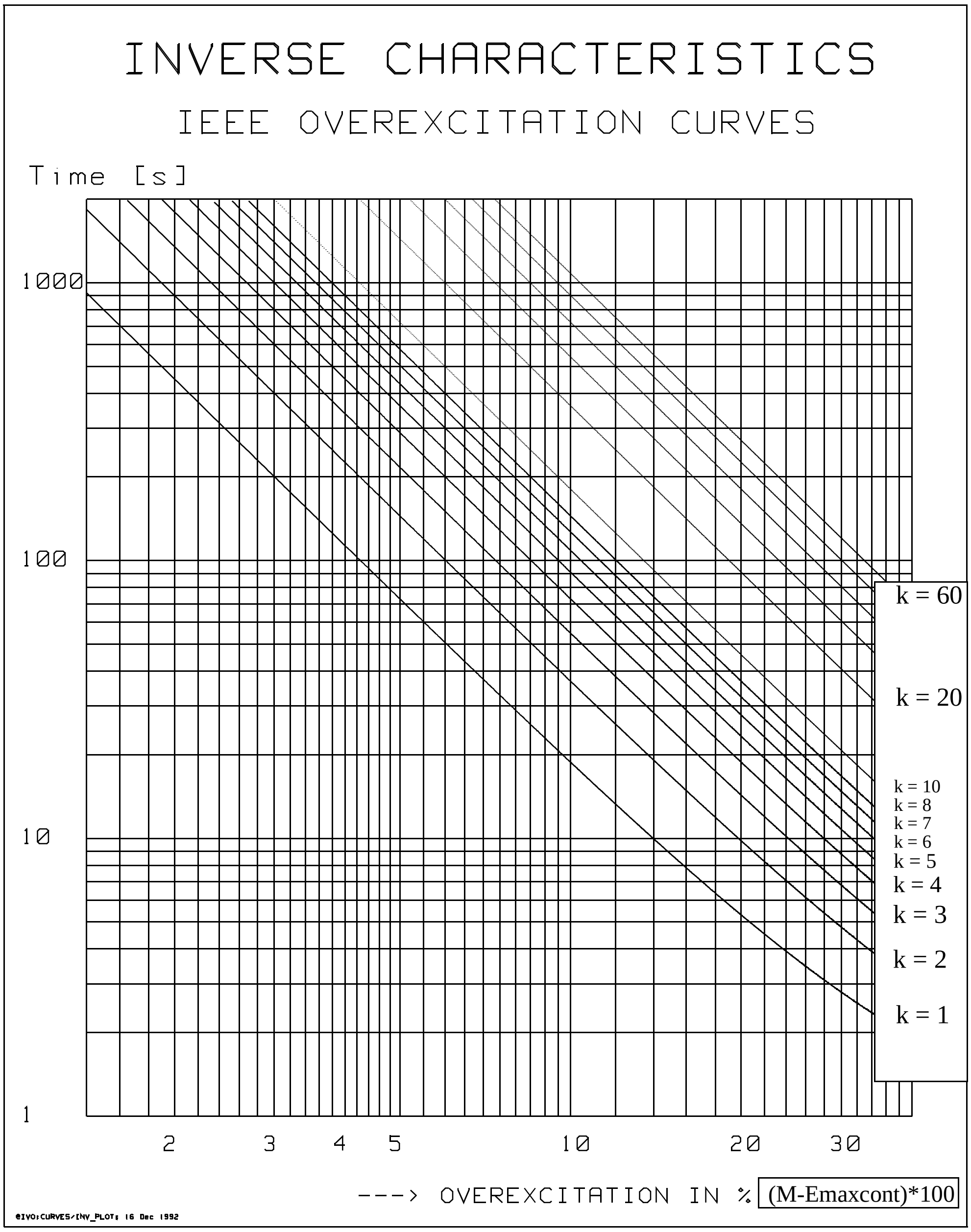


Fig. 93 Delays inversely proportional to the square of the overexcitation.

The critical value of excitation Mmax is determined indirectly via OVEX protection function setting Emax. Emax can be thought of as a no-load-rated-frequency voltage, where the inverse law should be replaced by a short definite delay, tMin. If, for example, Emax = 1.40 pu, then Mmax is:

$$Mmax = \frac{(Emax)/f}{Ur/fr} = 1.40$$

The **Tailor-Made** law allows a user to himself or herself construct an arbitrary delay characteristic. In this case the interval between M = Emaxcont, and M = Mmax is automatically divided into five equal subintervals, with six delays. (settings t1, t2, t3, t4, t5, and t6) as shown in Fig. 94. These times should be set so that t1 => t2 => t3 => t4 => t5 => t6.

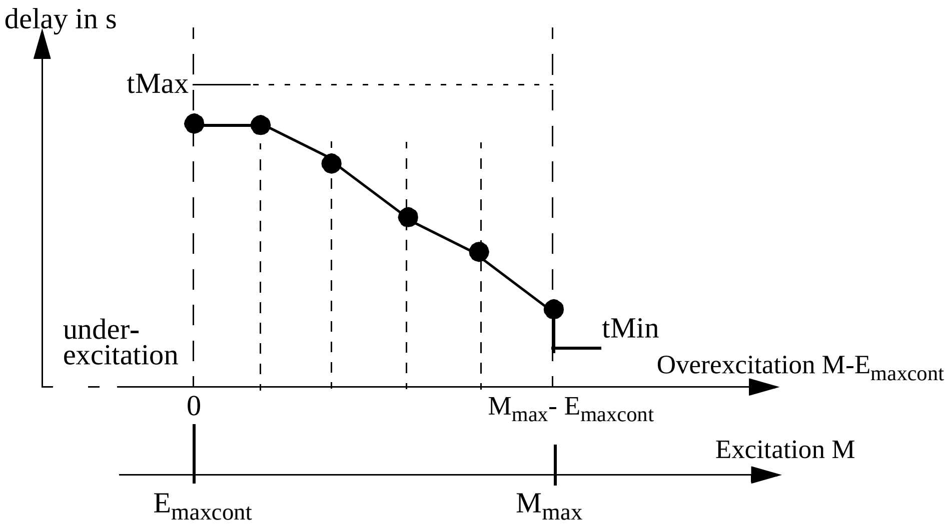


Fig. 94 An example of a Tailor-Made delay characteristic

Delays between two consecutive points, for example t3 and t4, are obtained by linear interpolation.

Should it happen that tMax be lower than, for example, delays t1, and t2, the actual delay would be tMax. Above Mmax, the delay can only be tMin.

33.2.4 Cooling

The overexcitation protection OVEX is basically a thermal protection; therefore a cooling process has been introduced. Exponential cooling process is applied. Parameter Tcool is an OVEX setting, with a default time constant Tcool of 20 minutes. This means that if the voltage and frequency return to their previous normal values (no more overexcitation), the normal temperature is assumed to be reached not before approximately 5 times Tcool minutes. If an overexcitation condition would return before that, the time to trip will be shorter than it would be otherwise.

33.2.5 OVEX protection function service report

A service value data item called Time to trip, and designated on the display by tTRIP is available in seconds on the local HMI, or SMS. This value is an estimation of the remaining time to trip if the overexcitation remained on the level it had when the estimation was done. This information can be useful with small or moderate overexcitations. If the overexcitation is so low that the valid delay is tMax, then the estimation of the remaining time to trip is done against tMax.

The displayed relative excitation M, designated on the display by V/Hz is calculated from the expression:

$$M = relative\left(\frac{V}{Hz}\right) = \frac{E/f}{Ur/fr}$$

If less than V / Hz = Emaxcont (in pu) is shown on the HMI display (or read via SM/RET521), the power transformer is underexcited. If the value of V/Hz is shown which is equal to Emaxcont (in pu), it means that the excitation is exactly equal to the power transformer continuous capability. If a value higher than the value of Emaxcont is shown, the protected power transformer is overexcited. For example, if V / Hz = 1.100 is shown, while Emaxcont = 1.1 pu, then the power transformer is exactly on its maximum continuous excitation limit.

The third item of the OVEX protection service report is the thermal status of the protected power transformer iron core, designated on the display by ThermalStatus. This gives the thermal status in% of the trip value which corresponds to 100%. Thermal Status should reach 100% at the same time, when tTRIP reaches 0 seconds. If the protected power transformer is then for some reason not switched off, the ThermalStaus shall go over 100%.

If the delay as per IEEE law, or Tailor-made Law, is limited by tMax, and/or TMin, then the Thermal Status will generally not reach 100% at the same time, when tTRIP reaches 0 seconds. For example, if, at low degrees of overexcitation, the very long delay is limited by tMax, then the OVEX TRIP output signal will be set to 1 before the Thermal status reaches 100%.

33.3 Logic diagram

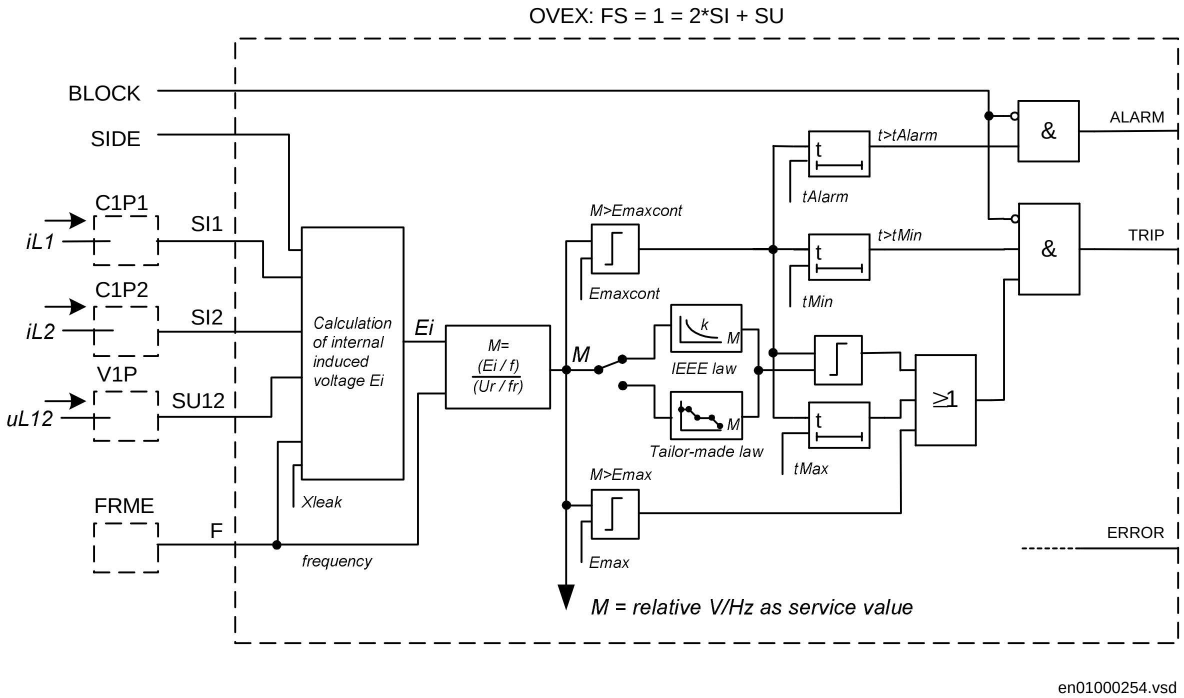


*Fig. 95 A simplified diagram of the OVEX protection function for Function Selector 2*SI+SU.*

Simplification of the diagram is in the way the IEEE and Tailor-made delays are calculated. The cooling process is not shown. It is not shown that voltage and frequency are separately checked against their respective limit values.

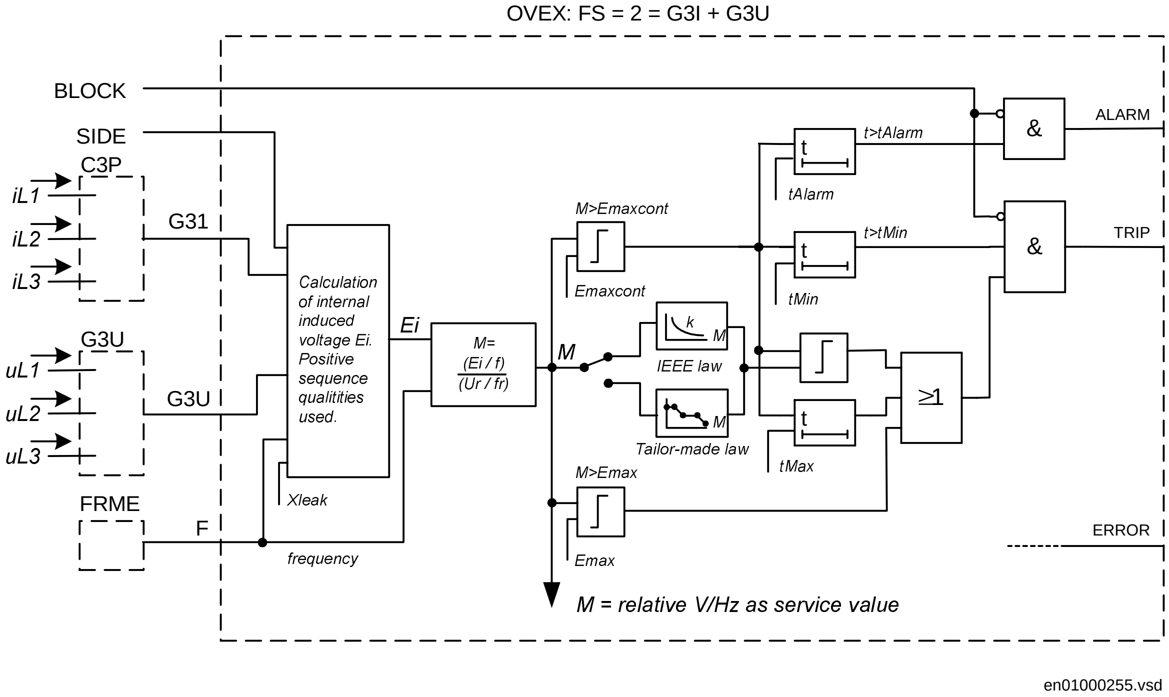
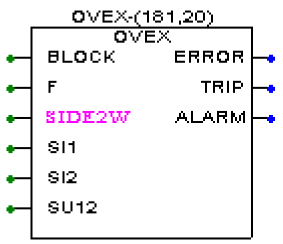


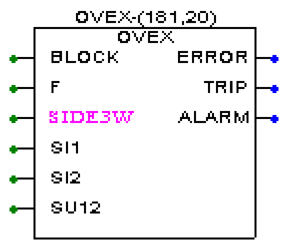
Fig. 96 A simplified diagram of the OVEX protection function for Function Selector G3I+G3U.

33.4 Function block

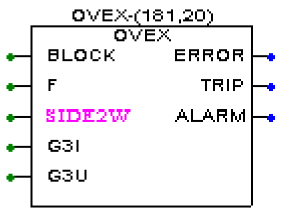
Two versions are available of the OVEX protection function block: versions for 2-winding power transformers are shown on the left side, while the corresponding versions for 3-winding transformers on the right side. There is one instance of OVEX protection function available in RET 521.

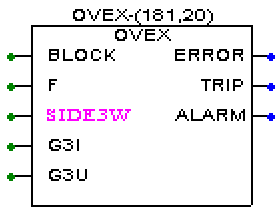
Function Selector 2*SI + SU. A phase-to-phase voltage, and two corresponding phase (terminal) currents must be fed to the OVEX function block.





Function Selector G3I + G3U. Three phase-to-earth voltages, and three phase (terminal) currents must be fed to the OVEX function block





33.5 Input and output signals

Table 103: OVEX protection function block: input signals for FS = 2 * SI + SU

In:	Description:
OVEX:BLOCK	External block, OVEX
OVEX:F	Actual frequency, OVEX
OVEX:SIDE2W or OVEX:SIDE3W	Transformer side, OVEX
OVEX:SI1	Single phase current 1, OVEX
OVEX:SI2	Single phase current 2, OVEX
OVEX:SU12	Phase-to-phase voltage, OVEX

Table 104: OVEX protection function block: input signals for FS = G3I + G3U

In:	Description:
OVEX:BLOCK	External block, OVEX
OVEX:F	Actual frequency, OVEX
OVEX:SIDE2W or OVEX:SIDE3W	Transformer side, OVEX
OVEX:G3I	Three phase current group, OVEX
OVEX:G3U	Three phase voltage group, OVEX

Table 105: OVEX protection function block: output signals

Out:	Description:	Type	Range
OVEX:ERROR	General OVEX function error	Integer	0 - 1
OVEX:TRIP	Common trip OVEX	Integer	0 - 1
OVEX:ALARM	Alarm limit exceeded, OVEX	Integer	0 - 1

33.6 Setting parameters and ranges

Table 106: OVEX protection function: settings, their ranges and descriptions

Parameter:	Range:	Description:
Operation	0 - 1	Operation Overexcitation Protection (V/Hz)
Emaxcon	1.00 - 1.50	Emax continous no-load, in p.u.
Emax	1.20 - 1.80	Excitation with tMin delay, in p.u.
tMin	0.50 - 30.00	Minimum operating time in sec.
tMax	10 - 120	Maximum time delay for overexcitation, in min
k	1 - 60	Time multiplier for inverse time function
Tcool	5 - 120	Transformer cooling time constant, in min.
tAlarm	0 - 120	Time delay for alarm, in sec.
t1	0 - 7200	Time value in sec. for Time 1
t2	0 - 7200	Time value, in sec. for Time 2
t3	0 - 7200	Time value, in sec. for Time 3
t4	0 - 7200	Time value, in sec. for Time 4
t5	0 - 7200	Time value, in sec. for Time 5
t6	0 - 7200	Time value, in sec. for Time 6
CurveType	0 - 1	Time characteristic for OVEX, IEEE / Tailor-made
Xleak	0.000 - 0.250	Winding reactance in p.u. Sr base

33.7 Service report values

Table 107: OVEX protection function: service report

Parameter:	Range:	Step:	Description:
tTRIP	0 - 7200	1	Time to trip overexcitation, in sec.
V/Hz	0.000 - 10.000	0.001	Relative voltage to frequency ratio.
ThermalStatus	0.0 - 1000.0	0.1	Thermal status in % of trip value

34 Frequency protection function (FRF)

34.1 Summary of application

Over/under frequency protection can be used for several power system protection and control applications. Two examples are underfrequency load shedding and power generation unit protection.

In RET 521 up to three FRF modules can be ordered. Each module has one overfrequency and one underfrequency stage with independently settable frequency pickup and definite time delay.

34.2 Summary of function

The over and under frequency function is comparing the available frequency value, measured by the existing frequency measurement function (FRME), with settable over and under frequency limits. The frequency value from FRME is also used to control the adaptive filters and to give frequency value input to the overexcitation function. See description of FRME in paragraph 24.

The FRF has two settable integrating delay timers one for over frequency and one for under frequency function. The timers have settable reset times.

The FRF function runs in the medium task with 20 ms (16.667 ms in 60 Hz) execution time.

34.3 Measuring principles

34.3.1 Input quantity

The frequency value (f) to FRFx is got from FRME by connecting the FRME frequency output to the FRFx frequency input in the CAP configuration.This naturally means that FRME also has to be configured in an appropriate way to the voltage which actually is used for the calculation of the frequency value. The FRME also has to be enabled with its On/Off setting parameter.

It is also recommended to connect the FRME ERROR output signal to the FRFx blocking inputs BLKOFR/BLKUFR (at least BLKUFR).

The FRME ERROR output signal will be high and then block the frequency protection when either the frequency is out of the guaranteed frequency range or the measuring voltage level is too low.

34.3.2 Basic operation

The FRF is a single quantity measuring device with two independent measuring stages, one for over frequency measurement and one for under frequency measurement.
The setting is done with the parameters FrsetOver and FrsetUnder respectively.

The FRF has got no hysteresis or 100% reset ratio.

34.3.3 Time Characteristics

34.3.3.1 Constant delay

Both over and under frequency measuring functions have an own constant delay function.The constant time is set by the setting parameter tDefOver and tDefUnder respectively. In order to get a settable reset time a summation S of execution cycles is made to get the time criterion.

$$\left(S = \sum_{j=1}^{n} \Delta t \right) \geq tDefOver$$

j = 1 a start has been achieved, for the first time it is f > FrsetOver

Δt time interval between two successive executions of FRF function. If the FRF protection is executed with an execution frequency f_{ex} = 250 Hz, then Δt = 1/250 s = 4 ms, (16,667 ms for 60 Hz).

n an integer, the number of the FRF function execution intervals Δt from the start to the point of time when the above condition for trip is fulfilled and trip command issued.

34.3.3.2 Reset time

If the FRF function has started but not timed out and then the frequency falls within the over/under frequency operate value the time accumulation counter value is reduced with a value each execution time (kResetOver*Δt or kResetUnder*Δt). Eg when kResetOver/kResetUnder = 1 the counting up at a start of FRF has the same rate as the counting down when FRF is resetting.

$$\left(S = \left[\sum_{j=1}^{n} \Delta t - \sum_{i=1}^{m} kResetOver \times \Delta t \right] \right) \geq tDefOver$$

The j value is increased as long as f > FrsetOver and the trip not is achieved and the i value is increased if f < FrsetOver until the S counter equals zero.

A temporary block input activation, when the input frequency is above/below the operate value and FRF function thus has started but still not timed out and not given a trip signal, will reset the timer to zero. That means that when the block activation disappear the timer will start to count from zero again.

34.3.4 Main conditions and specifications for the frequency function FRF

If FRME is disabled or not configured frequency is =0.000 Hz.

If voltage is below dependable voltage limit FRME outputs the frequency is =50.000 Hz. (60.000 Hz if rated frequency is 60 Hz).

Accuracy for FRF when FRME is connected to three phases (either phase to earth or phase to phase connection).

Accuracy of measured frequency (0.7 - 1.2) of fr	± 2 mHz
50% second, third or fifth harmonic dependency	± 7 mHz
Voltage dependency (0.8 - 1.2) of Ur	± 2 mHz

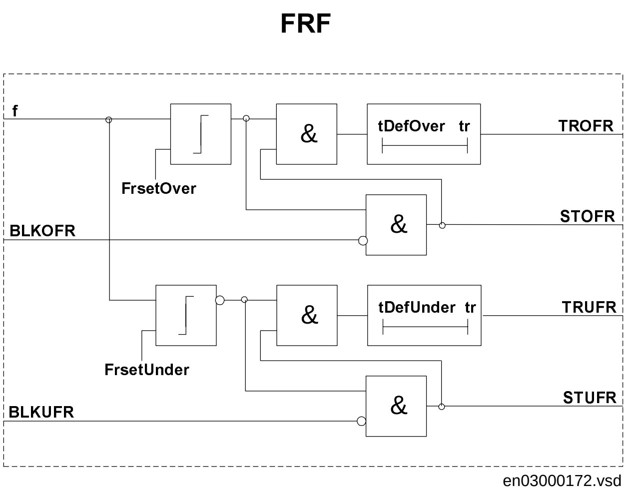
Accuracy for FRF when FRME connected between two phases

Accuracy of measured frequency (0.7 - 1.2) of fr	± 35 mHz
50% second, third or fifth harmonic dependency	± 20 mHz
Voltage dependency (0.8 - 1.2) of Ur	± 50 mHz

Voltage limit for operation 40% of rated phase to earth voltage.

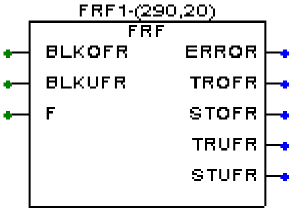
The pick up of the FRME at 10 Hz/sec frequency change is 250 to 375 ms and the reset time is 300 to 400 ms.

34.4 Logic diagram



34.5 Function block

There is one function block type available for the FRF protection.



34.6 Input and output signals

Table 108: FRFx function block: input signals (x = 1, 2, 3)

In:	**Description:**
FRFx:BLKOFR	External block overfrequency stage, FRFx
FRFx:BLKUFR	External block underfrequency stage, FRFx
FRFx:F	Frequency value input, FRFx

Table 109: FRFx function block:ouput signals (x = 1, 2, 3)

Out:	**Description:**
FRFx:ERROR	General FRFx function error
FRFx:TROFR	Trip overfrequency, FRFx
FRFx:STOFR	Start overfrequency, FRFx
FRFx:TRUFR	Trip underfrequency, FRFx
FRFx:STUFR	Start underfrequency, FRFx

34.7 Setting parameters and ranges

Table 110: FRFx settings, their ranges and descriptions

Parameter:	Range	Description
Operation	0 - 1	Operation Frequency Function Protection, Off/On
BlockOver	0 - 1	Block overfrequency Protection, Off/On
FrsetOver	30.000 -75.000	Start frequency for overfrequency Protection in Hz
tDefOver	0.00 - 300.00	Definite delay overfrequency Protection in sec.
kResetOver	0.1 - 1000.0	Reset time factor for overfrequency Protection.
BlockUnder	0 - 1	Block under frequency Protection , Off/On
FrsetUnder	30.000 -75.000	Start frequency for underfrequency Protection in Hz
tDefUnder	0.00 - 300.00	Definite delay underfrequency Protection in sec.
kResetUnder	0.1 - 1000.0	Reset time factor for underfrequency Protection.

34.8 Service report values

Table 111: FRFx protection function service value

Parameter:	Range:	Step:	Description:
f	0.000 - 99.999	0.001	Measured Frequency in Hz

35 Voltage control (VCTR)

35.1 Summary of function

The voltage control function (i.e. VCTR) is intended for control of power transformers with a motor driven on-load tap changer. The function is designed to regulate the voltage at the secondary side of the power transformer (winding No 2 under settings for Transformer Data). Control method is based on the step-by-step principle, which means that a control pulse, one at the time, will be issued to the tap changer mechanism to move it up or down for one position. Length of the control pulse can be set within wide range to accommodate different types of tap changer mechanisms. The pulse is generated by the VCTR whenever the measured voltage, for a given time, deviates from the set reference value by more then the preset deadband (i.e. degree of insensitivity). Time delay is used to avoid unnecessary operation during brief voltage deviations from the set value.

The VCTR function in RET 521 is designed in such a way that it always issues RAISE command in order to increase the voltage, and LOWER command in order to decrease the voltage.

The function can also include options for parallel control of up to four or up to eight power transformers, based on minimising the circulating current method, with terminal-to-terminal communication via LON bus.

For parallel control may alternatively the reverse reactance method be used in which case the terminal to terminal communication is not needed.

Furthermore it is also possible to arrange a master-follower concept for parallel operation with help of the CAP programmable logic and LON communication between the terminals.

35.2 Measuring principles

35.2.1 VCTR Operation Mode (i.e. Control Location)

It is possible to have the following human-machin-interfaces (i.e. HMI) and four operation modes (i.e. locations from where tap changer can be manually operated) for VCTR function in RET 521:

1. Internal HMI with operation mode (i.e. operation location)
   - RET 521 built-in HMI
2. External HMI with operation modes (i.e. operation location)
   - Local control panel (usually traditional control panel with selector switches)
   - Station Control (station control system i.e. SCS)
   - Remote Control (SCADA system)

35.2.2 Control Mode

The control mode of the VCTR can be:

- Manual
- Automatic

The control mode can be changed via the command menu in the built-in HMI when the operation mode is IntMMI or changed remotely via binary signals connected to the **EXTMAN**, **EXTAUTO** inputs on VCTR function block when the operation mode is ExtMMI.

35.2.3 Measured Quantities

The secondary side of the transformer is used as the voltage measuring point. If necessary, the secondary side current is used as load current to calculate the line-voltage drop to the regulation point. It is possible to use one of the following three different sets of analogue input quantities.

1) Three phase-to-earth voltages and all three phase currents from the power transformer secondary side. In this case VCTR will use internally calculated positive sequence voltage and current quantities for all calculations.

2) One phase-to-phase voltage and corresponding two phase currents from the power transformer secondary side.

3) One phase-to-ground voltage and corresponding phase current from the power transformer secondary side.

See Figure 97 for more details about different analogue input possibilities.

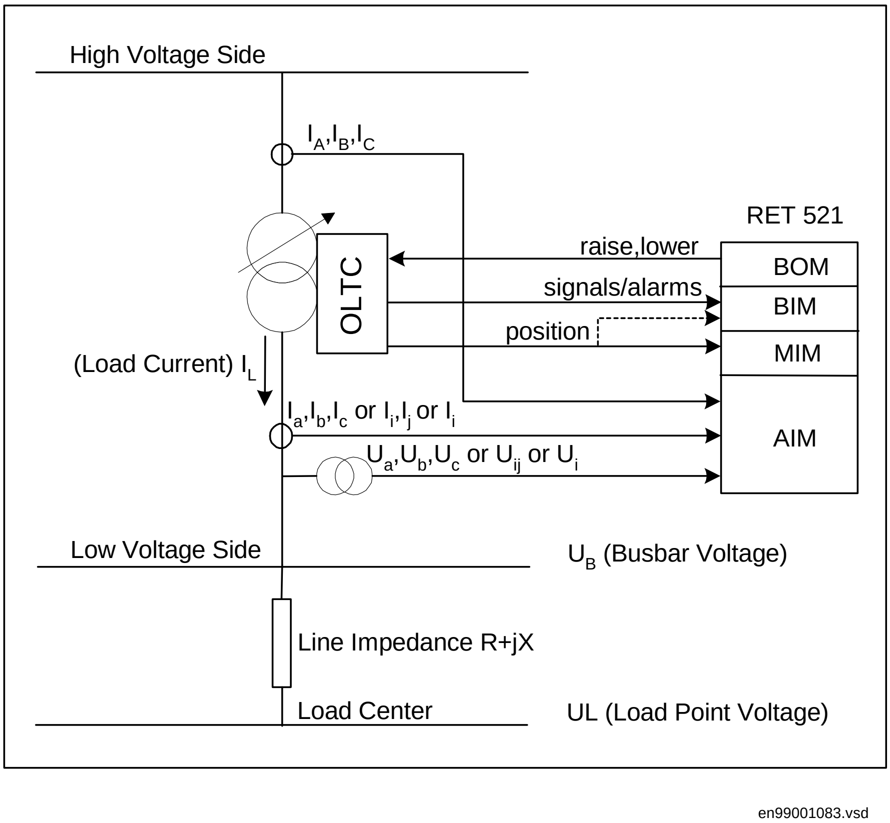


Fig. 97 Signal flow for a single transformer with voltage control function

The required option, can be selected via the Function Selector for VCTR function in the CAP configuration tool.

In addition, all three phase currents from the primary winding (i.e. usually winding where the tap changer is situated) are used by VCTR function for overcurrent blocking. These analogue input signals can be shared with other functions in the terminal, such as the differential protection function.

In figure 97, the busbar voltage U_B is a shorter notation for the measured voltage regardless of the type of analogue input. Therefore notation U_B will be used from here on. Similarly notation I_L for load current and U_L for load point voltage will be used in the text further on.

Other inputs to VCTR function is the actual position of the tap changer that can be monitored either by using a mA-input or binary inputs. Alarms and signals from the tap changer can also be connected to binary inputs, e.g. thermal overload switch for motor, oil pressure relay, tap changer in progress etc. The RAISE and LOWER commands to the tap changer are issued via two binary outputs that will be activated during a time corresponding to the output pulse duration time.

35.2.4 Voltage control for parallel transformers

Parallel voltage control, as implemented in RET 521, can be based on minimising the circulating current principle. Two main objectives of this type of parallel voltage control are:

1. Regulate the busbar or load voltage to the preset target value
2. Minimize the circulating current, in order to achieve optimal sharing of the reactive load between parallel transformers

The first objective is the same as for the voltage control for a single transformer while second objective tries to bring the circulating current, which appears due to unequal LV side no load voltages in each transformer, into an acceptable value. Figure 98 shows an example with two transformers connected in parallel. If transformer T1 on this picture has higher no load voltage it will drive a circulating current which adds to the load current in T1 and subtracts from the load current in T2. It can be shown that magnitude of the circulating current in this case can be approximately calculated with the following formula:

$$\left|I_{\mathrm{cc\_T1}}\right| = \left|I_{\mathrm{cc\_T2}}\right| = \left|\frac{U_{\mathrm{T1}} - U_{\mathrm{T2}}}{Z_{T1} + Z_{T2}}\right|$$

Because transformer impedance is dominantly inductive it is possible to use just transformer reactances in the above formula. In the same time this means that T1 circulating current lags the busbar voltage for almost 90^{o}, while T2 circulating current leads the busbar voltage for almost 90^{o} (see figure 99 for complete phasor diagram). This shows that circulating current is mainly of reactive nature.

Therefore by minimizing the circulating current flow through transformers the total reactive power flow is optimized as well. In the same time at this optimum state the apparent power flow is distributed among transformers in the group in proportion to their rated power.

An important task for the VCTR function for parallel control is the calculation of the circulating current. To achieve this goal certain information and measurements have to be exchanged via the station bus (i.e. LON bus) between the terminals.

It should be noted that the Fourier filters in each RET 521 terminal run asynchronously which means that current and voltage phasors cannot be exchanged and used for calculation directly between the terminals. In order to “synchronize” measurements within all terminals in the parallel group, a common reference have to be selected. The only suitable reference quantity for all transformers, which belong to one parallel group, is the busbar voltage. This means that the measured busbar voltage is used as a reference phasor in all terminals, and the position of the current phasors in the complex plain is calculated in respect to it. This is a simple and effective solution which eliminates any additional need for synchronization between terminals regarding VCTR function.

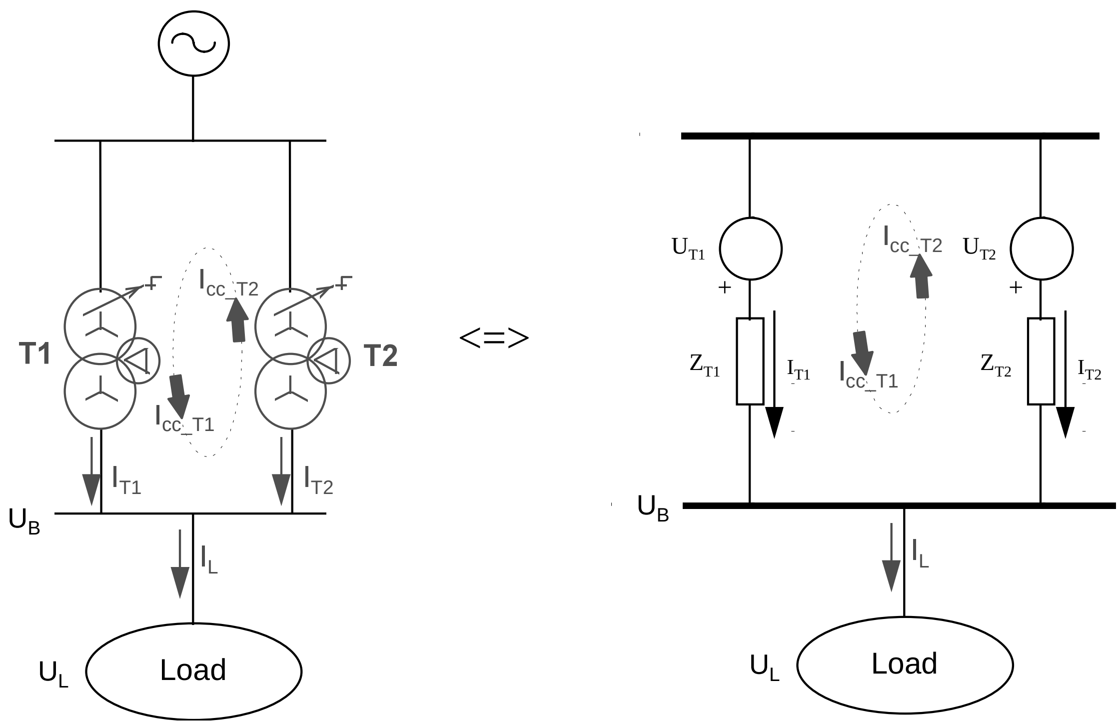


Fig. 98 Parallel group of two power transformers and its electrical model

At each transformer bay the real and imaginary part of the current on the secondary side of the transformer is measured and distributed on the station LON bus to the terminals that belong to the parallel group.

As mentioned before, only the imaginary part (i.e. reactive current component) of the individual transformer current is needed for the circulating current calculations. The real part of the current will, however, be used to calculate the total through load current and will be used by the line voltage drop compensation.

The total load current in pu is defined as sum of all individual transformer currents:

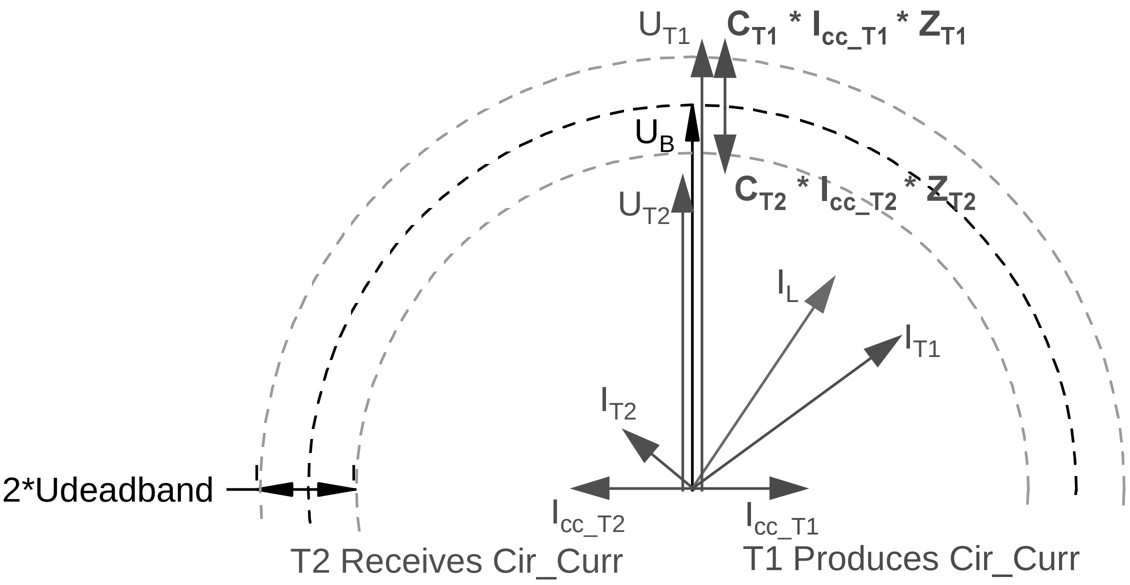
$$\overline{I_L} = \sum_{i=1}^{k} \overline{I_i}$$

where subscript *i* signifies the transformer bay number and *k* the number of parallel transformers in the group. Next step is to extract the circulating current I_{cc_i} that flows in bay *i*. It is possible to identify a term in the bay current which represents the circulating current. The magnitude of the circulating current in bay *i*, I_{cc_i} , can be calculated according to:

$$I_{\mathrm{cc\_i}} = -\mathrm{Im}(\overline{I_i} - \overline{K_{Li}} \times \overline{I_L})$$

where *Im* means the imaginary part of the expression in brackets and $\overline{K_i}$ is a constant which depends on the number of transformers in the parallel group and their short-circuit reactances. VCTR function automatically calculates this constant. Transformer reactances should be given in primary ohms, calculated from each transformer rating plate.

The minus sign is added in above equation in order to have positive value of the circulating current for the transformer which generates it.



$$\underline{I}_L = \underline{I}_{T1} + \underline{I}_{T2}$$
$$I_{cc\_T1} = Imag\,\{\underline{I}_{T1} - (Z_{T2}/(Z_{T1}+Z_{T2})) * \underline{I}_L\}$$
$$I_{cc\_T2} = Imag\,\{\underline{I}_{T2} - (Z_{T1}/(Z_{T1}+Z_{T2})) * \underline{I}_L\}$$

Fig. 99 Vector Diagram for two power transformers working in parallel.

In this way each VCTR function calculates the circulating current for its own bay.

The calculated circulating current I_{cc_i} is shown on the HMI as a service value under menu

Service Report
Functions
VoltageControl
Measurands
CircCurrent

Sign is available as well (i.e. + sign means that the transformer produces circulating current and - sign means that the transformer receives circulating current).

Now it is necessary to estimate the value of the no-load voltage in each transformer. To do that the magnitude of the circulating current, in each bay, is first transferred to a voltage deviation, U_{di}, as per the following formula:

$$U_{\mathrm{di}} = C_i \cdot I_{\mathrm{cc\_i}} \cdot X_i$$

where X_i is the short-circuit reactance for transformer *i* and C_i, is a setting parameter called "**Comp**" which can increase/decrease the influence of the circulating current on the VCTR function. It should be noted that U_{di} will have positive values for transformer which produces circulating current and negative values for transformers which receives circulating current.

Now for each transformer the magnitude of the no-load voltage can be approximated with:

$$U_i = U_B + U_{\mathrm{di}}$$

This value for the no-load voltage is then simply put into the voltage control function for single transformer, that treats it as the measured busbar voltage, and further control actions are taken as described in section 35.2.4. By doing this the overall control strategy is simple and can be summarized as follows.

For the transformer producing/receiving the circulating current calculated no-load voltage will be greater/lower than measured voltage U_B. This calculated no-load voltage is thereafter compared with the set voltage U_{set}. A steady deviation which is outside the deadband will result in a LOWER / RAISE voltage command to the tap changer. In this way the overall control action is always correct since the position of a tap changer is directly proportional to the transformer no-load voltage.

Complete phasor diagram for case of two transformers connected in parallel is shown on figure 99.

35.2.5 Plant with Capacitive shunt compensation

If the power plant has got a considerable capacitive shunt generation not symmetrically connected to all transformers in the group of parallel operating transformers the situation may call for input of the capacitive current to the terminal for compensation of its influence. An asymmetric connection will exist if eg the capacitor is situated on the secondary winding between the ct measuring point and the power transformer or at the tertiary winding of the power transformer, see Fig. 100. Then the capacitive current will interact in opposite way in the different terminals on the calculation of the circulating currents. The capacitive current is part of the imaginary load currents and therefore essential in the calculation. The calculated circulating currents and the real circulating currents will in this case differ from each other and not be minimum at the same time. This might result in that minimising the calculated circulating currents not will regulate the tap changers to the same tap positions even if the power transformers are equal.

However if the capacitive current also are brought into the terminal on separate current inputs this current easily can be added to the current from the measuring ct inside the terminal by appropriate CAP configuration of the terminal. Then the influence from the capacitor bank can be completely compensated for.

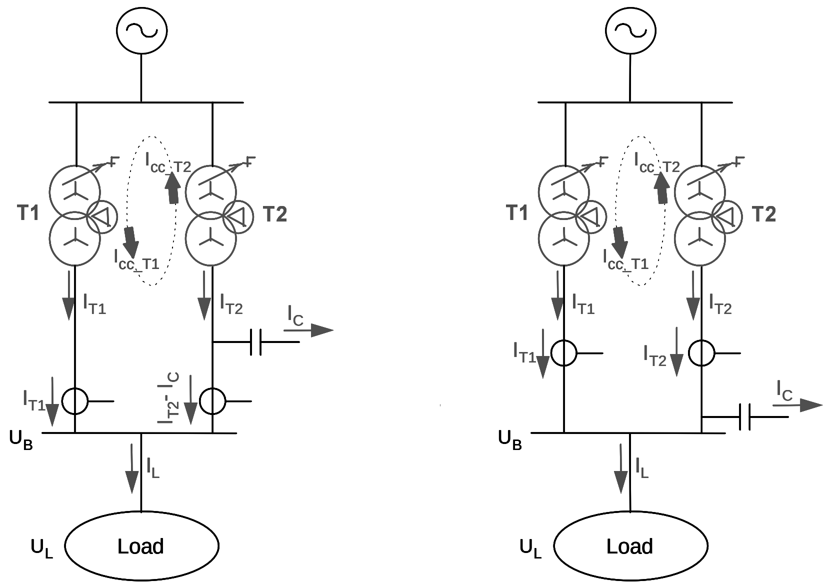


Fig. 100 Plant with capacitive compensation

From Fig. 100 it is quite obvious that the two different connections of the capacitor are completely the same regarding the currents in the primary net. However the ct measured currents for transformer T2 differs with an amount equal to the capacitor current. If the actual connection is as in the left figure the capacitive current I_C can be added to the actual ct current (I_{T2}-I_C) to give the transformer current I_{T2}

35.2.6 Manual Control of the parallel group (Adapt Mode)

In the previous section automatic control of the parallel group was described. In manual control mode for parallel transformers the operator can choose to operate each tap changer individually. Each terminal control mode must then be set to “Manual”.

It is also possible to control the transformers as a group. The control mode for one terminal is then set to “Manual” whereas other terminals are left in “Automatic”. Terminals in the automatic mode will be automatically put in the adapt mode. As the name indicates they will be ready to adapt to the manual tapping of the selected transformer. The VCTR function in manual mode will send the adapt message via LON bus to the rest of group. It is of no importance for the group members to know from which transformer bay the adapt message was sent.

The VCTR function in adapt mode will continue the calculation of U_{di}, but instead of adding U_{di} to the measured busbar voltage, it will compare it with the deadband ΔU. The following rules are used:

Rule 1: If U_{di} is positive and its module is greater than ΔU, then initiate a LOWER command. Tapping will take place after appropriate t1/t2 timing.

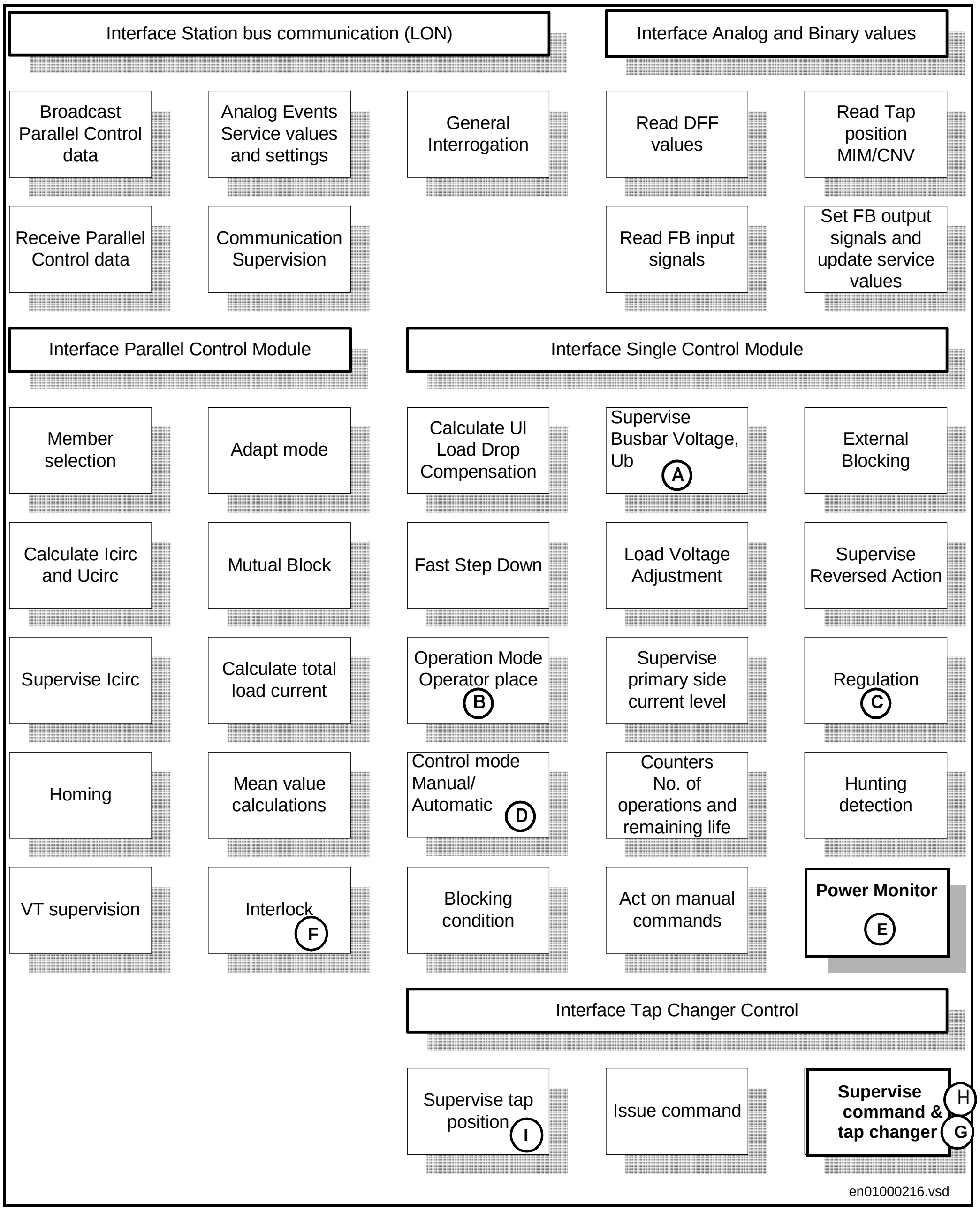
Rule 2: If U_{di} is negative and its module is greater than ΔU, then initiate a RAISE command.Tapping will take place after appropriate t1/t2 timing.

Rule 3: If U_{di} module is smaller than ΔU, then do nothing.

The binary output signal “**ADAPT”** on VCTR function block will be set high to indicate that this terminal is adapting to another RET terminal in the parallel group.

However, it should be noted that correct behavior of all transformers in the parallel group can be guaranteed only when one and only one of the transformers is set to the manual mode.

35.3 Logic diagram



A See Fig. 102
B See Fig. 103
C See Fig. 105 and Fig. 106
D See Fig. 104
E See Fig. 107
F See Fig. 108
G See Fig. 109
H See Fig. 110
I See Fig. 111

Fig. 101 VCTR overview

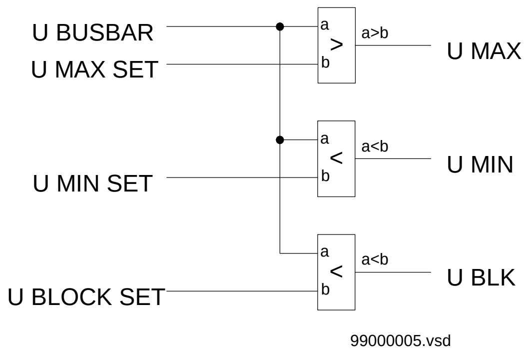


Fig. 102 Supervision of busbar voltage Ub

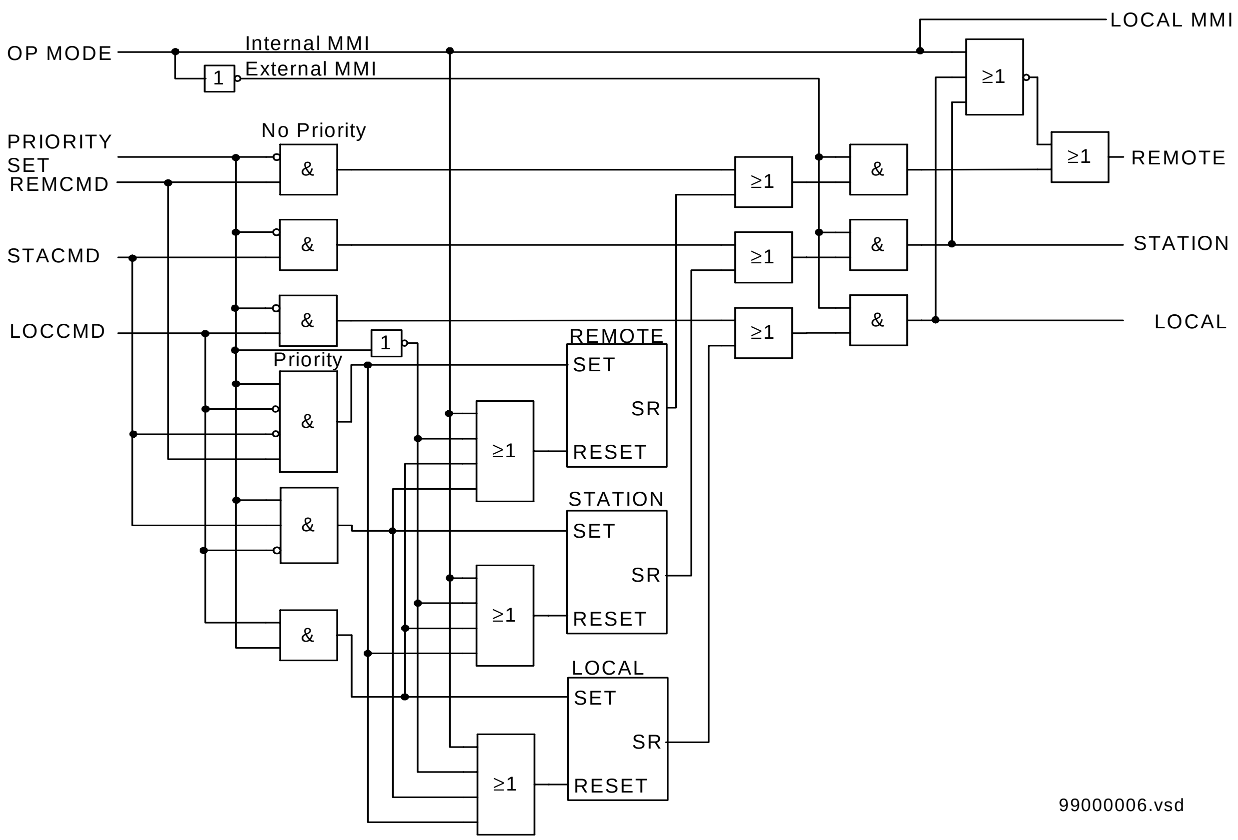


Fig. 103 Operation mode

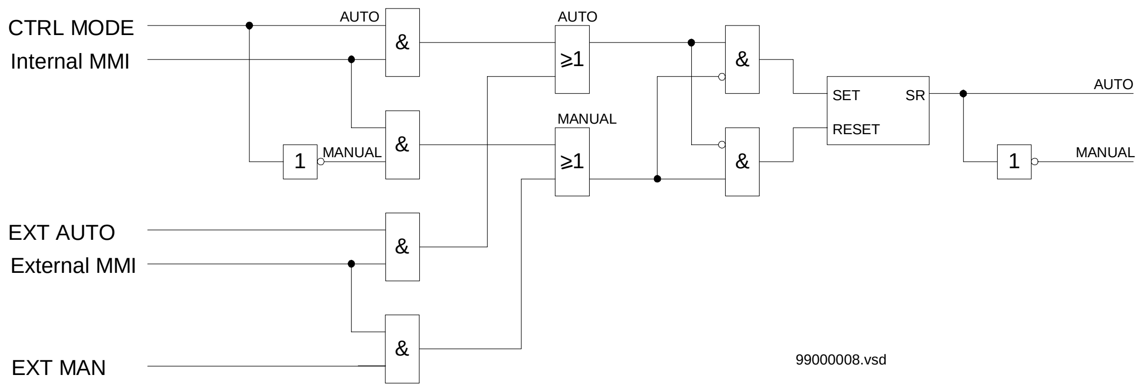


Fig. 104 Control mode

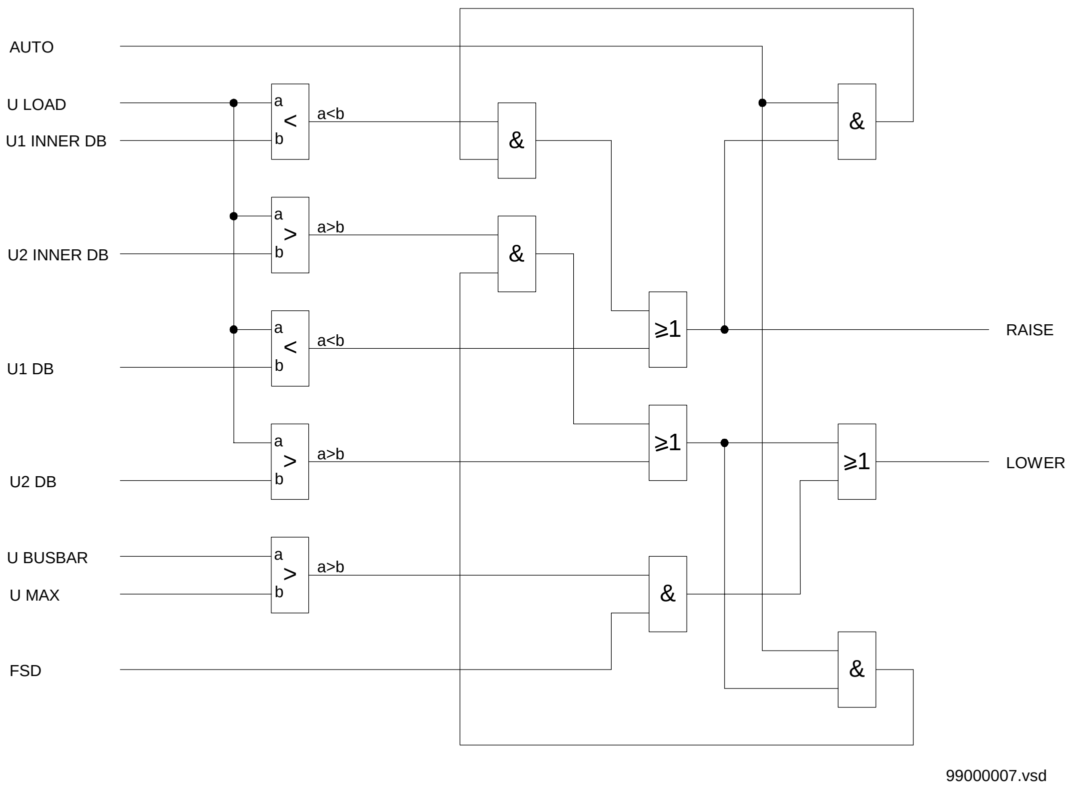


Fig. 105 Regulation principle single mode operation

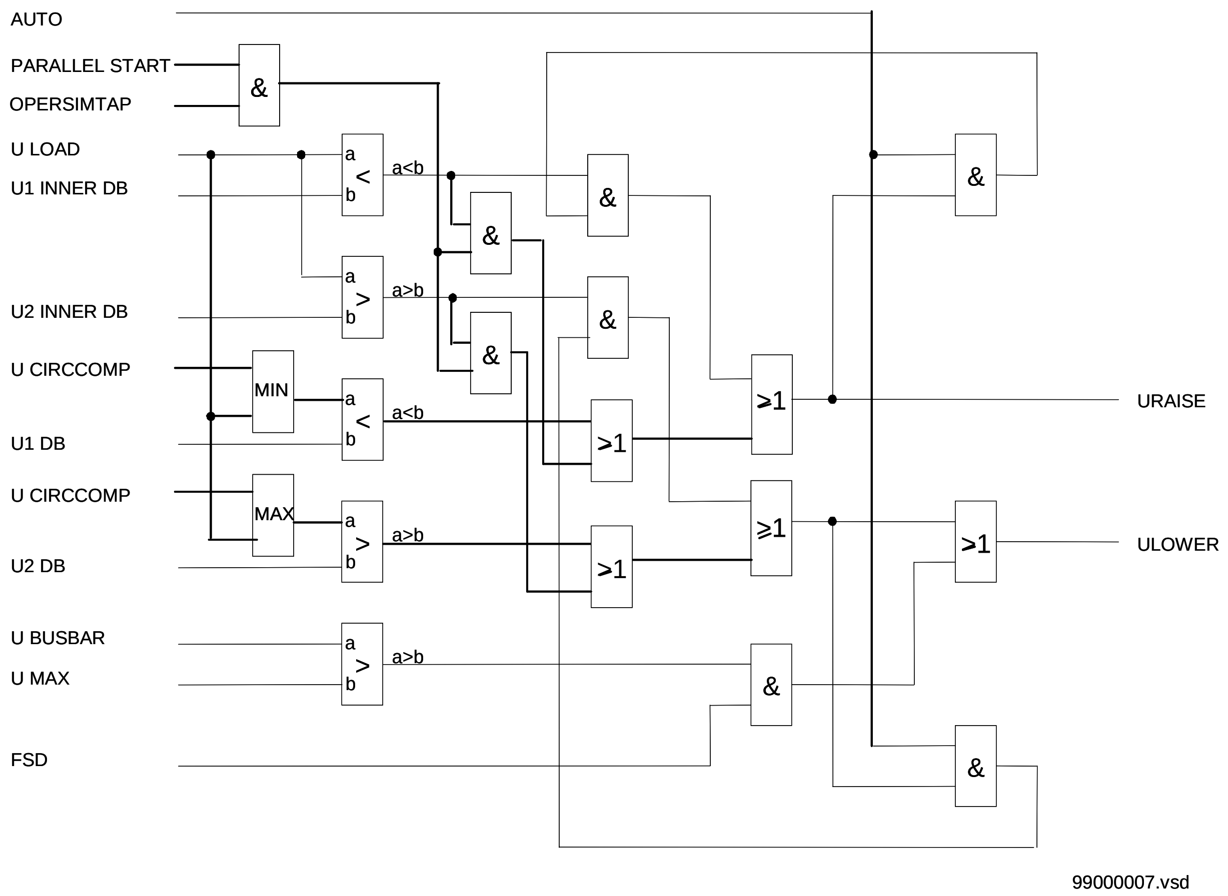


Fig. 106 Regulation principle parallel mode operation

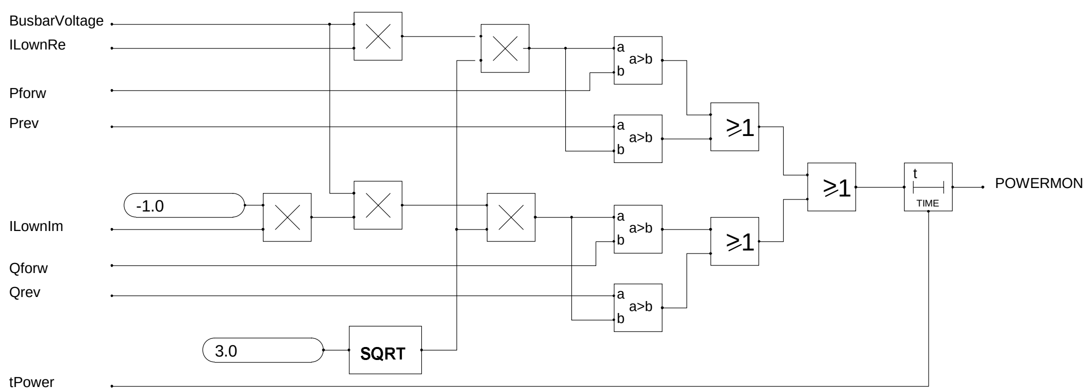


Fig. 107 Power Monitor

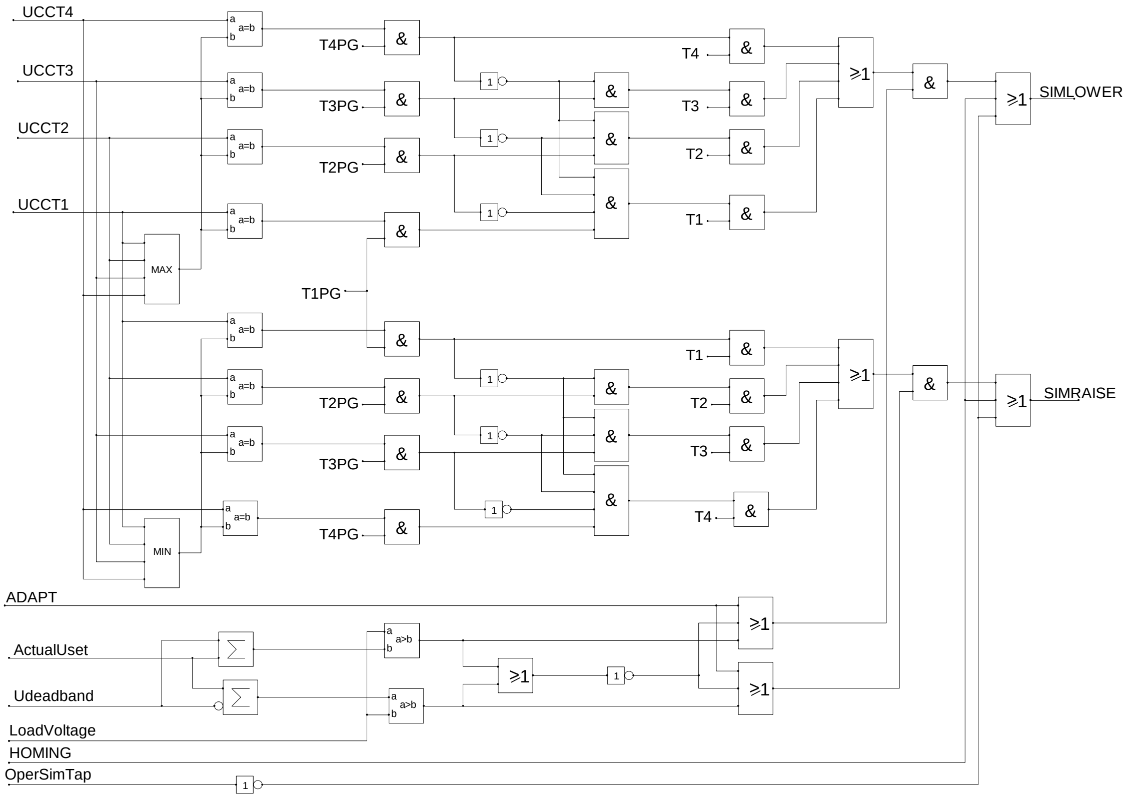


Fig. 108 Simplified Interlocking logic for four parallel transformers

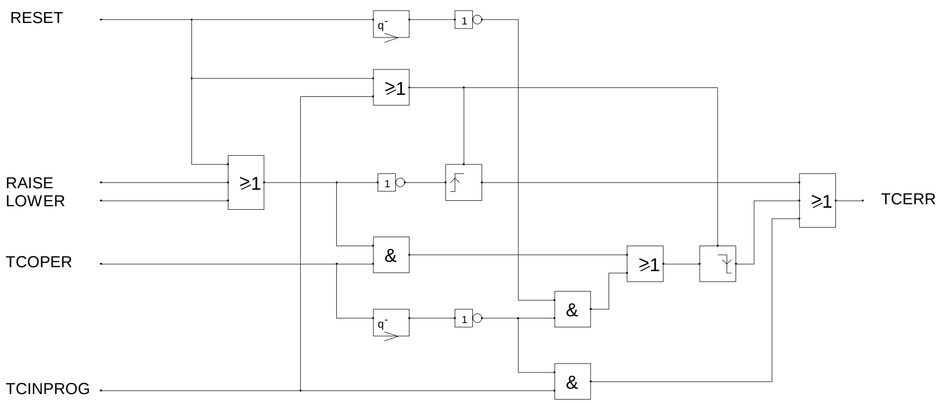


Fig. 109 Logic for tap changer error signal (TCERR)

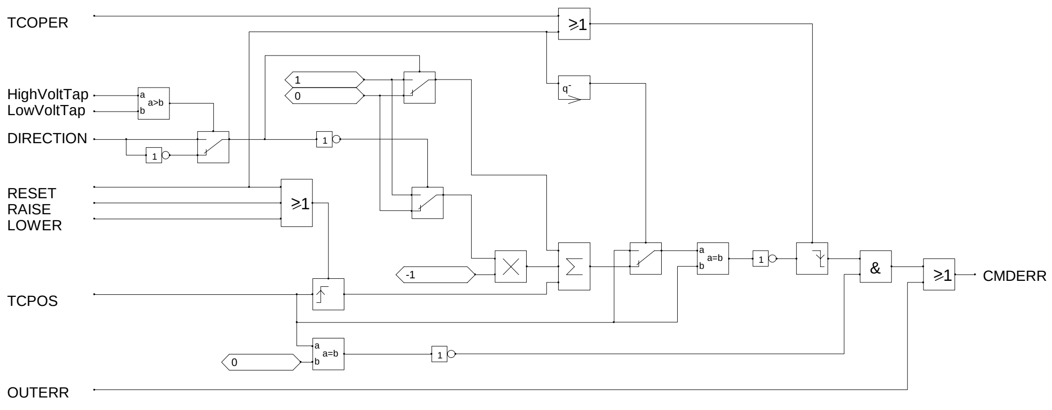


Fig. 110 Logic for command error signal (CMDERR)

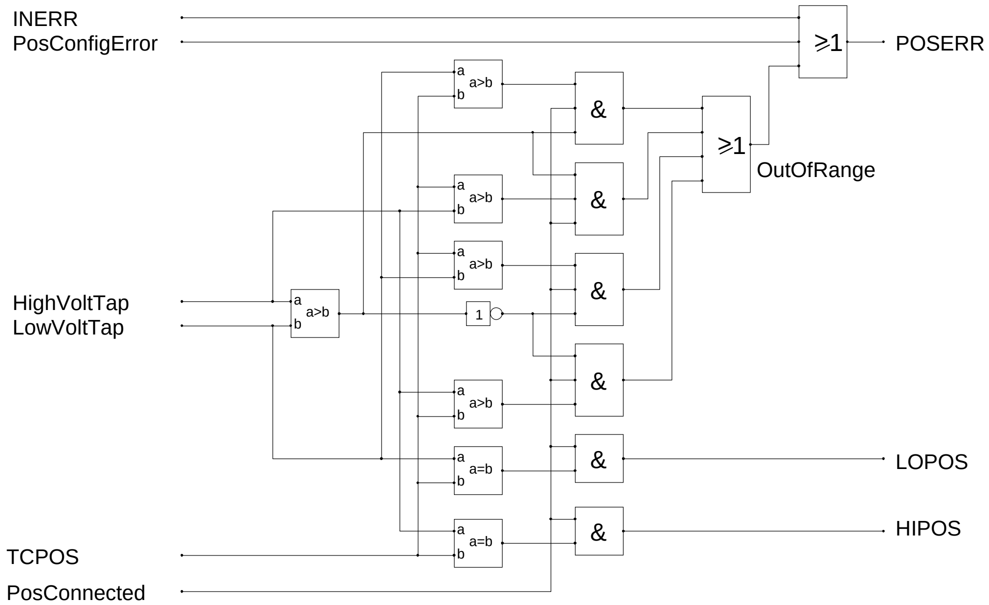
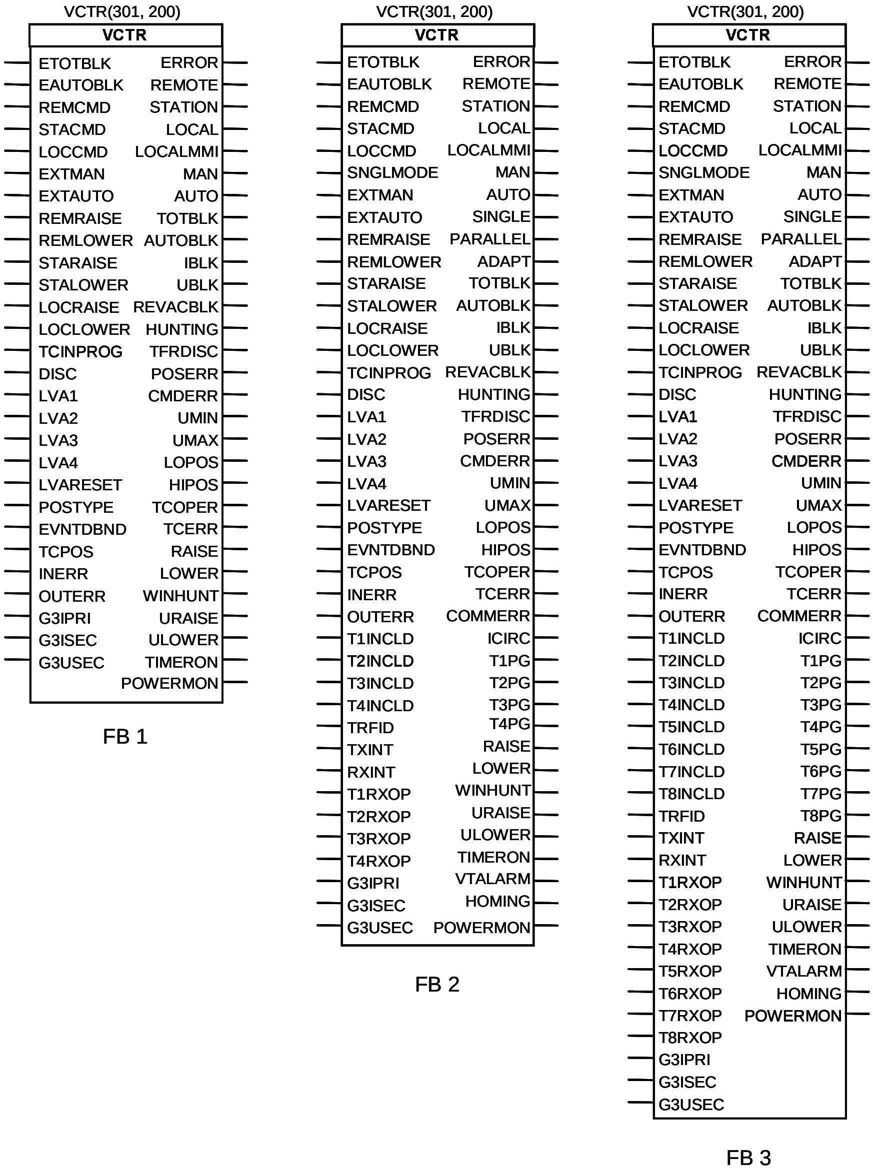


Fig. 111 Logic for position error signal (POSERR)

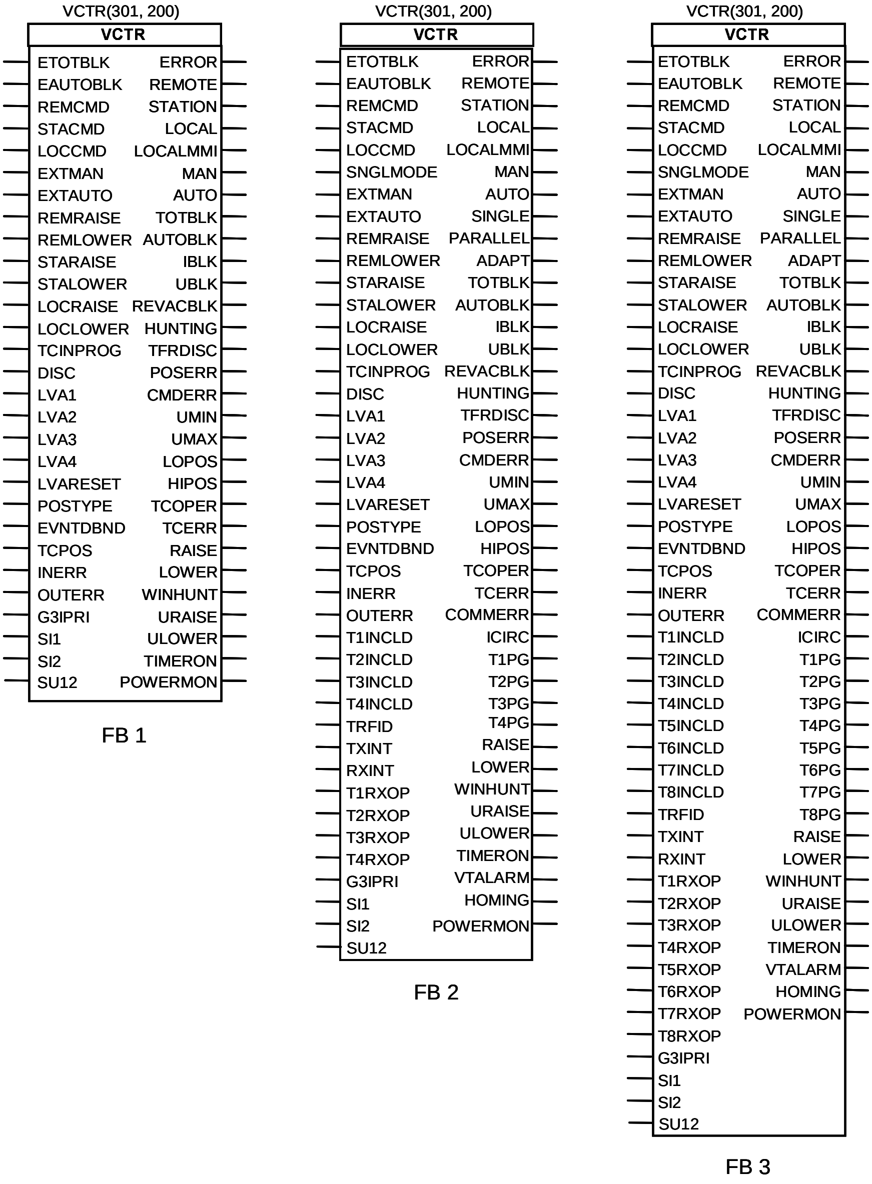
35.4 Function block

For Voltage Control, VCTR, there are three different looks of the function block.
VCTR (function selector set to G3I+G3U)
Three-phase currents and three-phase voltages used for regulation



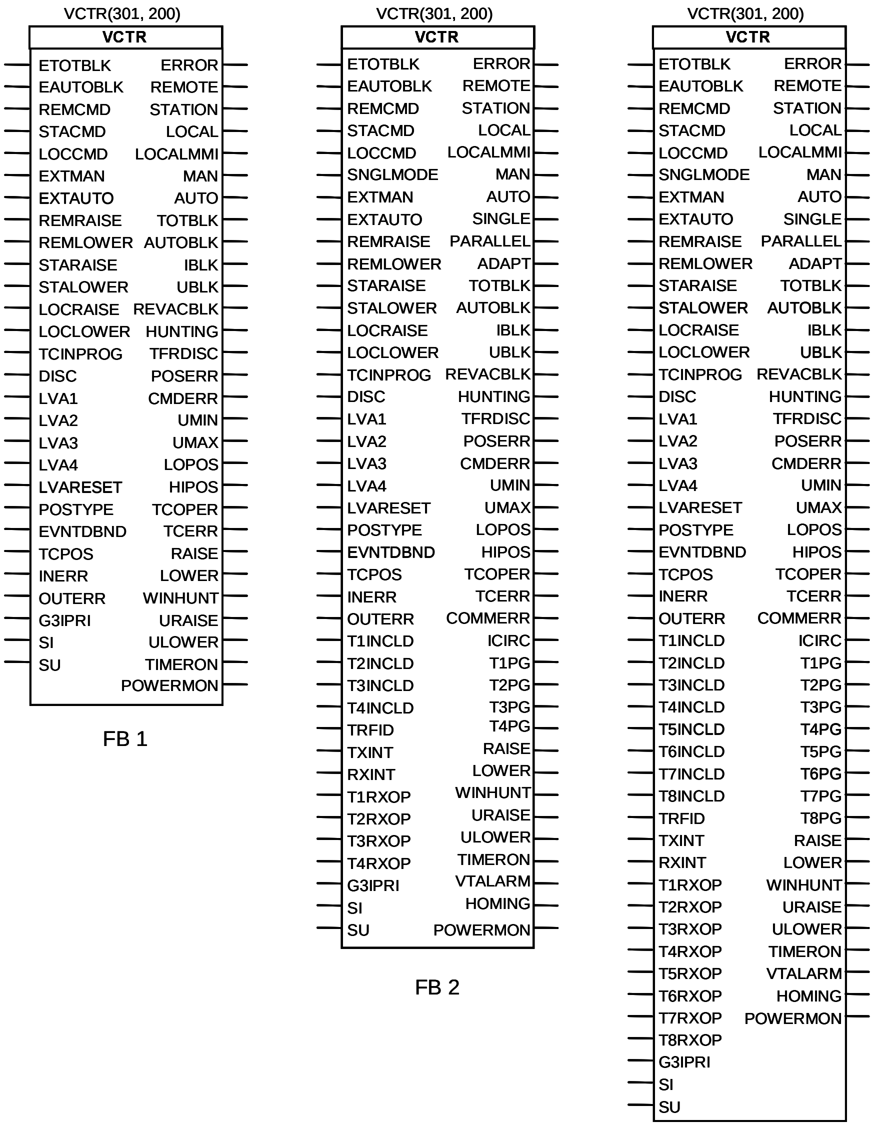
FB1 is for single transformer operation
FB2 is for parallel transformer operation (max four units)
FB3 is for parallel transformer operation (max eight units)

VCTR (function selector set to 2*SI+SU)
Two phase currents and corresponding phase to phase voltage used for regulation



FB1 is for single transformer operation
FB2 is for parallel transformer operation (max four units)
FB3 is for parallel transformer operation (max eight units)

VCTR (function selector set to SI+SU)
Single phase current and corresponding single phase to ground voltage used for regulation.



FB1 is for single transformer operation
FB2 is for parallel transformer operation (max four units)
FB3 is for parallel transformer operation (max eight units)

35.5 Input and output signals

Table 112:

In:	Description:
VCTR-ETOTBLK	Total blocking of voltage control
VCTR-EAUTOBLK	Blocking of automatic mode
VCTR-REMCMD	Enables remote MMI
VCTR-STACMD	Enables station MMI
VCTR-LOCCMD	Enables local panel switches
VCTR-SNGLMODE	Force single control mode
VCTR-EXTMAN	Manual control mode
VCTR-EXTAUTO	Automatic control mode
VCTR-REMRAISE	Manual raise pulse, remote location
VCTR-REMLOWER	Manual lower pulse, remote location
VCTR-STARAISE	Manual raise pulse, station location
VCTR-STALOWER	Manual lower pulse, station location
VCTR-LOCRAISE	Manual raise pulse, local location
VCTR-LOCLOWER	Manual lower pulse, local location
VCTR-TCINPROG	Tap changer in progress signal
VCTR-DISC	Disconnected transformer indication
VCTR-LVA1	Activation of load voltage adjust. factor 1
VCTR-LVA2	Activation of load voltage adjust. factor 2
VCTR-LVA3	Activation of load voltage adjust. factor 3
VCTR-LVA4	Activation of load voltage adjust. factor 4
VCTR-LVARESET	Reset of load voltage adjust. factor
VCTR-POSTYPE	See settings table
VCTR-EVNTDBND	See settings table
VCTR-TCPOS	Tap changer position indication
VCTR-INERR	Input module error
VCTR-OUTERR	Output module error
VCTR-T1INCLD	Transformer T1 included in parallel group
VCTR-T2INCLD	Transformer T2 included in parallel group
VCTR-T3INCLD	Transformer T3 included in parallel group
VCTR-T4INCLD	Transformer T4 included in parallel group
VCTR-T5INCLD	Transformer T5 included in parallel group
VCTR-T6INCLD	Transformer T6 included in parallel group
VCTR-T7INCLD	Transformer T7 included in parallel group
VCTR-T8INCLD	Transformer T8 included in parallel group

Table 112:

In:	Description:
VCTR-TRFID	See settings table
VCTR-TXINT	See settings table
VCTR-RXINT	See settings table
VCTR-T1RXOP	See settings table
VCTR-T2RXOP	See settings table
VCTR-T3RXOP	See settings table
VCTR-T4RXOP	See settings table
VCTR-T5RXOP	See settings table
VCTR-T6RXOP	See settings table
VCTR-T7RXOP	See settings table
VCTR-T8RXOP	See settings table
VCTR-SI1	Single phase current 1
VCTR-SI2	Single phase current 2
VCTR-G3IPRI	Three phase current group primary side
VCTR-G3ISEC	Three phase current group secondary side
VCTR-SU12	Phase-to-phase voltage
VCTR-G3USEC	Three phase voltage group secondary side
VCTR-SU	Single phase voltage

Out:	Description:
VCTR-ERROR	General VCTR function error
VCTR-REMOTE	Remote operation mode
VCTR-STATION	Station operation mode
VCTR-LOCAL	Local operation mode
VCTR-LOCALMMI	Local MMI operation mode
VCTR-MAN	Manual control mode
VCTR-AUTO	Automatic control mode
VCTR-SINGLE	Single control mode
VCTR-PARALLEL	Parallel control mode
VCTR-ADAPT	Parallel control in adapt mode
VCTR-TOTBLK	Voltage control total blocking
VCTR-AUTOBLK	Voltage control automatic mode blocking
VCTR-IBLK	High current block, total block
VCTR-UBLK	Low voltage range block limit, auto mode block

VCTR-REVACBLK	OLTC reversed action blocking, auto mode block
VCTR-HUNTING	Hunting detection alarm
VCTR-TFRDISC	Transformer disconnection, auto mode block
VCTR-POSERR	Tap changer position error
VCTR-CMDERR	Tap changer command error
VCTR-UMIN	Low voltage range limit, lower command block
VCTR-UMAX	High voltage range limit, raise command block
VCTR-LOPOS	Low tap changer position indication, lower cmd. block
VCTR-HIPOS	High tap changer position indication, raise cmd. block
VCTR-TCOPER	Tap changer in operation
VCTR-TCERR	Tap changer operation error
VCTR-COMMERR	Communication error
VCTR-ICIRC	Maximum circulating current blocking
VCTR-T1PG	Transformer T1 connected to parallel group
VCTR-T2PG	Transformer T2 connected to parallel group
VCTR-T3PG	Transformer T3 connected to parallel group
VCTR-T4PG	Transformer T4 connected to parallel group
VCTR-T5PG	Transformer T5 connected to parallel group
VCTR-T6PG	Transformer T6 connected to parallel group
VCTR-T7PG	Transformer T7 connected to parallel group
VCTR-T8PG	Transformer T8 connected to parallel group
VCTR-RAISE	Raise voltage command to tap changer
VCTR-LOWER	Lower voltage command to tap changer
VCTR-URAISE	Raise voltage range limit
VCTR-ULOWER	Lower voltage range limit
VCTR-WINHUNT	Hunting detection alarm sliding window
VCTR-TIMERON	Timer T1 or T2 is running
VCTR-VTALARM	VT supervision alarm
VCTR-HOMING	Homing function status
VCTR-POWERMON	Power monitoring function output

35.6 Setting parameters and ranges

Table 113: Setting parameters and ranges in CAP tool

Parameter:	Range:	Description:
T1RXOP	0=Off, 1=On	Receive block operation for parallel transformer 1
T2RXOP	0=Off, 1=On	Receive block operation for parallel transformer 2
T3RXOP	0=Off, 1=On	Receive block operation for parallel transformer 3
T4RXOP	0=Off, 1=On	Receive block operation for parallel transformer 4
T5RXOP	0=Off, 1=On	Receive block operation for parallel transformer 5
T6RXOP	0=Off, 1=On	Receive block operation for parallel transformer 6
T7RXOP	0=Off, 1=On	Receive block operation for parallel transformer 7
T8RXOP	0=Off, 1=On	Receive block operation for parallel transformer 8
EVNTDBND	0.000-50.00	Event generation deadband in % of last value
RXINT	2.000-60.00	Receive interval
TXINT	2.000-60.00	Send interval
TRFID	0=T1, 1=T2, 2=T3, 3=T4	Transformer identity in the parallel group
POSTYPE	0=None, 1=BI, 2=AI	Tap changer position indication type

Table 114: Setting parameters and ranges

Parameter:	Range:	Description:
Operation	0=Off, 1=On	Operation Voltage Control
Uset	85.0 - 120.0	Voltage Control set voltage in % of Ur2
Udeadband	0.5 - 9.0	Set voltage deadband in % of Ur2
UdeadbandIn	0.1 - 9.0	Set inner deadband in % of Ur2
Umax	80 - 180	Upper limitation busbar voltage detection in % of Ur2

Table 114: Setting parameters and ranges

Parameter:	Range:	Description:
Umin	70 - 120	Lower limitation busbar voltage detection in % of Ur2
FSDMode	0=Off, 1=Auto, 2=AutoMan	Fast step down function activation mode
t1Use	0=Const, 1=Inverse	Time characteristics for Time 1
t1	1 - 300	Time value in sec. for Time 1
t2Use	0=Const, 1=Inverse	Time characteristics for Time 2, Const/Inverse
t2	1 - 300	Time value in sec. for Time 2
tMin	1.0 - 30.0	Minimum operating time in sec.
OperationLDC	0=Off, 1=On	Operation line voltage drop compensation
Rline	0.00 - 150.00	Line resistance, primary values, in ohm
Xline	-150.00 - 150.00	Line reactance, primary values, in ohm
OperCapaLDC	0 = Off, 1 = On	Operation capacitive LDC function
LVAConst1	-9.0 - 9.0	Constant load voltage adj. factor 1 in % of Ur2
LVAConst2	-9.0 - 9.0	Constant load voltage adj. factor 2 in % of Ur2
LVAConst3	-9.0 - 9.0	Constant load voltage adj. factor 3 in % of Ur2
LVAConst4	-9.0 - 9.0	Constant load voltage adj. factor 4 in % of Ur2
VRAuto	-4.0 - 4.0	Automatic voltage reduction factor in % of Ur2
ExtMMIPrio	0=Priority, 1=NoPriority	External MMI operation priority mode
TotalBlock	0=Off, 1=On	Total block of the voltage control function
AutoBlock	0=Off, 1=On	Automatic mode block of the voltage control function
Ublock	50 - 90	Undervoltage block level in % of Ur2
OperationRA	0=Off, 1=On	Operation OLTC reversed action blocking
tRevAct	30 - 360	Power system emergency blocking time in sec.

Table 114: Setting parameters and ranges

Parameter:	Range:	Description:
Pforw	- 9999.99 to 9999.99	Power monitoring operate level for active power in forward direction in MW
Prew	- 9999.99 to 9999.99	Power monitoring operate level for active power in reverse direction in MW
Qforw	- 9999.99 to 9999.99	Power monitoring operate level for reactive power in forward direction in MW
Qrew	- 9999.99 to 9999.99	Power monitoring operate level for reactive power in reverse direction in MW
tPower	0 - 60	Power monitoring time delay in sec.
OperationPAR	0=Off, 1=On	Parallel operation
T1Xr2	0.1 - 20.0	Transformer 1 reactance, secondary side, in ohm
T2Xr2	0.1 - 20.0	Transformer 2 reactance, secondary side, in ohm
T3Xr2	0.1 - 20.0	Transformer 3 reactance, secondary side, in ohm
T4Xr2	0.1 - 20.0	Transformer 4 reactance, secondary side, in ohm
T5Xr2	0.1 - 20.0	Transformer 5 reactance, secondary side, in ohm
T6Xr2	0.1 - 20.0	Transformer 6 reactance, secondary side, in ohm
T7Xr2	0.1 - 20.0	Transformer 7 reactance, secondary side, in ohm
T8Xr2	0.1 - 20.0	Transformer 8 reactance, secondary side, in ohm
Comp	0 - 2000	Parallel control compensation parameter in %
OperationCC	0=Off, 1=On	Operation circulating current block function
CircCurrLimit	0.0 - 20000.0	Circulating current block limit in A
tCircCurr	1 - 300	Circulating current delay time in seconds

Table 114: Setting parameters and ranges

Parameter:	Range:	Description:
LowVoltTap	0, 1- 64	Tap changer extreme position, lowest voltage. The zero setting has got a special autoblock overriding purpose described in Application manual.
HighVoltTap	0, 1 - 64	Tap changer extreme position, highest voltage. The zero setting has got a special autoblock overriding purpose described in Application manual.
Iblock	0 - 250	The tap changer overcurrent block level in % of Ir1
tPulseDur	0.5 - 5.0	Command output pulse duration time in sec.
tTCTimeout	1 - 60	Tap changer constant timeout time in sec.
DayHuntDetect	0 - 100	Hunting detection alarm, max operations/day
HourHuntDetect	0 - 30	Hunting detection alarm, max operations/hour
tHuntDetect	1 - 120	Time sliding window hunting detection in min.
NoOpWindow	0 - 30	Hunting detection alarm, max operation/window
CLFactor	1.0 - 3.0	Contact life counter factor
InitCLCounter	0 - 9999999	Initial value for tap changer life counter
OperUsetPar	0=Off, 1=On	Operation common set point for parallel operation, Off/On
OperSimTap	0=Off, 1=On	Operation simultaneous tapping prohibited, Off/On
OperHoming	0=Off, 1=On	Operation homing function, Off/On
VTmismatch	0.5 - 10.0	VTmismatch in % of Ur2
tVTmismatch	1.0 - 60.0	VTmismatch time in sec.

35.7 Service report values

Table 115:

Parameter:	Range:	Step:	Description:
ActualUsetSngl	0.0 - 1999.9	0.1	Actual set voltage compensated for voltage adj. in kV
BlockCond	0 - 3	1	Status of the voltage ctrl. blocking cond,None/Tot/Auto/Part
BusbarVoltage	0.0 - 1999.9	0.1	Actual busbar voltage in kV
CircCurrent	0.0 - 20000.0	0.1	Actual reactive circulating current in A
CLResetDate	yy-mm-dd hh.mm;ss.sss		SPA presentation of last date of CL reset
ContactLife	0 - 9999999	1	Number of remaining operations for contacts, count(s)
CompVoltage	0.0 - 1999.9	0.1	Calculated phase-to-phase load point voltage in kV
NoOfOperations	0 - 9999999	1	Total number of operations, count(s)
OCResetDate	yy-mm-dd hh.mm;ss.sss		SPA presentation of last date of op cnt reset
TapPosition	1 - 64	1	Actual tap changer position
BusVoltParl	0.0 - 1999.9		Actual busbar voltage parallel in kV
ActualUsetParl	0.0 - 1999.9	0.1	Actual set voltage compensated for voltage adj. parallel in kV
LVAInput	0 - 4	1	Actual set LVA input

Monitoring functionality

36 LED indication function (HL, HLED)

36.1 Application

Each LED indication can be set individually to operate in six different sequences; two as follow type and four as latch type. Two of the latching types are intended to be used as a protection indication system, either in collecting or re-starting mode, with reset functionality. The other two are intended to be used as a signaling system in collecting mode with an acknowledgment functionality.

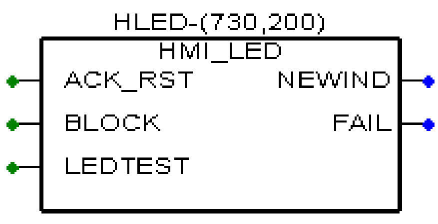
36.2 Design

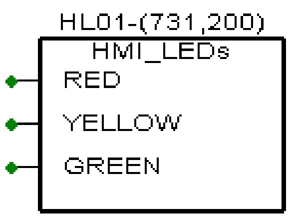
The LED indication function consists of one common function block named HLED and one function block for each LED named HL01, HL02,..., HL18.

The color of the LEDs can be selected in the function block to red, yellow or green individually. The input signal for an indication has separate inputs for each color. If more than one color is used at the same time, the following priority order is valid; red, yellow and green, with red as highest priority.

The information on the LEDs is stored at loss of the auxiliary power for the terminal, so that the latest LED picture appears immediately after the terminal has restarted succesfully.

36.3 Function block





36.4 Input and output signals

Table 116: Input signals for the HMI_LEDs (HLnn-) function block

Signal	Description
RED	Signal input for indication with red color.
YELLOW	Signal input for indication with yellow color.
GREEN	Signal input for indication with green color.

Table 117: Input signals for the HMI_LED (HLED-) function block

Signal	Description
ACK-RST	Input to acknowledge/reset the indications on the LED-unit. To be used for external acknowledgement/reset.
BLOCK	Input to block the operation of the LED-unit. To be used for external blocking.
LEDTEST	Input for external LED test. Common for the whole LED-unit.

Table 118: Output signals for the HMI_LED (HLED-) function block

Signal	Description
NEWIND	Output that gives a pulse each time a new signal on any of the indication inputs occurs.
FAIL	Indication for overflow in HMI-LED buffer.

36.5 Setting parameters

Table 119: Setting parameters for the LED indication function

Parameter	Range	Default	Unit	Description
Operation	On, Off	On	-	Operation for the LED-function.
tRestart	0.0 - 90000.0 Step: 0.1	5.0	s	Defines the disturbance length after the last active signal has been reset or reached its tMax. Applicable only in mode LatchedReset-S.
tMax	0.0 - 90000.0 Step: 0.1	5.0	s	The maximum time an indication is allowed to affect the definition of a disturbance. Applicable only in mode LatchedReset-S.
SeqTypeLEDx	Follow-S, Follow-F, LatchedAck-F-S, LatchedAck-S-F, LatchedColl-S, LatchedReset-S	Follow-S	-	Sequence type for the indication in LED x (x = 1-18). S = Steady and F = Flashing light.

37 Event function (EV)

37.1 Summary of application

When using a Substation Automation system, time-tagged events can be continuously sent or polled from the terminal. These events can come from any available signal in the terminal that is connected to the Event function block. The Event function block can also handle double indication, that is normally used to indicate positions of high-voltage apparatus. With this Event function block in the RET 521 terminal, data can be sent to other terminals over the LON bus.

37.2 Summary of function

Both internal logical signals and binary input channels in the terminal can be connected to Event function blocks that provide time-tagged events. The time-tagging of the events that are emerging from internal logical signals have a resolution corresponding to the execution cyclicity of the Event function block. The time-tagging of the events that are emerging from binary input signals have a resolution of 1 ms.

37.3 Description of logic

37.3.1 General

In the RET 521 terminal up to 12 Event function blocks are available. Two of these, number 01 and 02 are executed in a loop with maximum speed. Event functions 03 to 07 are executed in a loop with mediate speed. Event functions 08 to 12 are executed in a loop with lowest speed. Refer to other document describing the execution details.

Each Event function block has 16 connectables corresponding to 16 inputs EVxx-INPUT1 to EVxx-INPUT16. Every input can be given a name with up to 19 characters from the CAP configuration tool.

The inputs can be used as individual events or can be defined as double indication events.

The inputs can be set individually from the Station Monitoring System (SMS) under the Mask-Event function as:

- No events
- OnSet, at
- OnReset, at
- OnChange, at

37.3.2 Double indication

Double indications are used to handle a combination of two inputs at a time, for example, one input for the open and one for the close position of a circuit breaker or disconnector. The double indication consists of an odd and an even input number. When the odd input is defined as a double indication, the next even input is considered to be the other input. The odd inputs has a suppression timer to suppress events at 00 states.

To be used as double indications the odd inputs are individually set from the SMS under the Mask-Event function as:

- Double indication
- Double indication with midposition suppression

Here, the settings of the corresponding even inputs have no meaning.

These states of the inputs generate events. The status is read by the station HMI on the status indication for the odd input:

- 00 generates an intermediate event with the read status 0
- 01 generates an close event with the read status 1
- 10 generates an open event with the read status 2
- 11 generates an undefined event with the read status 3

37.3.3 Communication between terminals

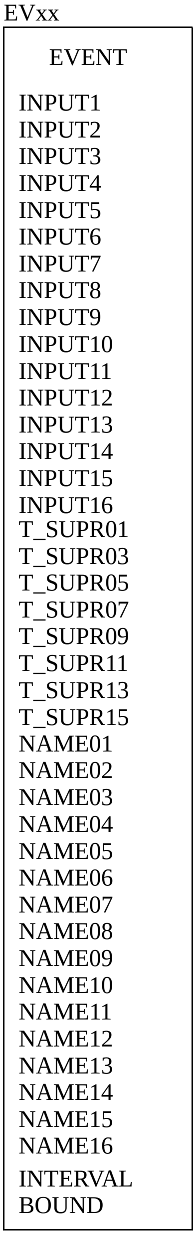
On the Event function block, the BOUND and INTERVAL inputs are available to be used for communication between terminals.

The BOUND input set to 1 means that the output value of the event block is bound to another control terminal on the LON bus. The Event function block is then used to send data over the LON bus to other terminals. The most common use is to transfer interlocking information between different bays. That can be performed by an Event function block used as a send block and with a Multiple Command function block used as a receive block. The configuration of the communication between control terminals is made by the LON Network Tool.

The INTERVAL input is applicable only when the BOUND input is set to 1. The INTERVAL is intended to be used for cyclic sending of data to other terminals via the LON bus with the interval time as set. This cyclic sending of data is used as a backup of the event-driven sending, which is always performed. With cyclic sending of data, the communication can be supervised by a corresponding INTERVAL input on the Multiple Command function block in another terminal connected to the LON bus. This INTERVAL input time is set a little bit longer than the interval time set on the Event function block. With INTERVAL=0, only event-driven sending is performed.

The event-driven sending of data to other control terminals over the LON bus is performed with a resolution corresponding to the execution cyclicity of the Event function block.

37.4 Function block



37.5 Input and output signals

Table 120: Signal list for Event function No. xx

In:	Description:
EVxx-INPUT1	Event input 1 for event block No. xx
EVxx-INPUT2	Event input 2 for event block No. xx
EVxx-INPUT3	Event input 3 for event block No. xx
EVxx-INPUT4	Event input 4 for event block No. xx
EVxx-INPUT5	Event input 5 for event block No. xx
EVxx-INPUT6	Event input 6 for event block No. xx
EVxx-INPUT7	Event input 7 for event block No. xx
EVxx-INPUT8	Event input 8 for event block No. xx
EVxx-INPUT9	Event input 9 for event block No. xx
EVxx-INPUT10	Event input 10 for event block No. xx
EVxx-INPUT11	Event input 11 for event block No. xx
EVxx-INPUT12	Event input 12 for event block No. xx
EVxx-INPUT13	Event input 13 for event block No. xx
EVxx-INPUT14	Event input 14 for event block No. xx
EVxx-INPUT15	Event input 15 for event block No. xx
EVxx-INPUT16	Event input 16 for event block No. xx

37.6 Setting parameters and ranges

Table 121: Setting table for Event function No. xx

Parameter:	Range:	Description:
EventMask1	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 1, to be set from SMS
EventMask2	No Events, OnSet, OnReset, OnChange	Event mask for input 2, to be set from SMS
EventMask3	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 3, to be set from SMS
EventMask4	No Events, OnSet, OnReset, OnChange	Event mask for input 4, to be set from SMS
EventMask5	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 5, to be set from SMS
EventMask6	No Events, OnSet, OnReset, OnChange	Event mask for input 6, to be set from SMS
EventMask7	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 7, to be set from SMS
EventMask8	No Events, OnSet, OnReset, OnChange	Event mask for input 8, to be set from SMS
EventMask9	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 9, to be set from SMS
EventMask10	No Events, OnSet, OnReset, OnChange	Event mask for input 10, to be set from SMS
EventMask11	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 11, to be set from SMS
EventMask12	No Events, OnSet, OnReset, OnChange	Event mask for input 12, to be set from SMS
EventMask13	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 13, to be set from SMS

Table 121: Setting table for Event function No. xx

Parameter:	Range:	Description:
EventMask14	No Events, OnSet, OnReset, OnChange	Event mask for input 14, to be set from SMS
EventMask15	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 15, to be set from SMS
EventMask16	No Events, OnSet, OnReset, OnChange	Event mask for input 16, to be set from SMS
EVxx-T_SUPR01	0.000-60.000 s	Suppression time for Input 1, to be set from CAP tool
EVxx-T_SUPR03	0.000-60.000 s	Suppression time for Input 3, to be set from CAP tool
EVxx-T_SUPR05	0.000-60.000 s	Suppression time for Input 5, to be set from CAP tool
EVxx-T_SUPR07	0.000-60.000 s	Suppression time for Input 7, to be set from CAP tool
EVxx-T_SUPR09	0.000-60.000 s	Suppression time for Input 9, to be set from CAP tool
EVxx-T_SUPR11	0.000-60.000 s	Suppression time for Input 11, to be set from CAP tool
EVxx-T_SUPR13	0.000-60.000 s	Suppression time for Input 13, to be set from CAP tool
EVxx-T_SUPR15	0.000-60.000 s	Suppression time for Input 15, to be set from CAP tool
EVxx-NAME01	19 characters string	User name of signal connected to Input 1, to be set from CAP tool
EVxx-NAME02	19 characters string	User name of signal connected to Input 2, to be set from CAP tool
EVxx-NAME03	19 characters string	User name of signal connected to Input 3, to be set from CAP tool
EVxx-NAME04	19 characters string	User name of signal connected to Input 4, to be set from CAP tool
EVxx-NAME05	19 characters string	User name of signal connected to Input 5, to be set from CAP tool
EVxx-NAME06	19 characters string	User name of signal connected to Input 6, to be set from CAP tool
EVxx-NAME07	19 characters string	User name of signal connected to Input 7, to be set from CAP tool
EVxx-NAME08	19 characters string	User name of signal connected to Input 8, to be set from CAP tool

Table 121: Setting table for Event function No. xx

Parameter:	Range:	Description:
EVxx-NAME09	19 characters string	User name of signal connected to Input 9, to be set from CAP tool
EVxx-NAME10	19 characters string	User name of signal connected to Input 10, to be set from CAP tool
EVxx-NAME11	19 characters string	User name of signal connected to Input 11, to be set from CAP tool
EVxx-NAME12	19 characters string	User name of signal connected to Input 12, to be set from CAP tool
EVxx-NAME13	19 characters string	User name of signal connected to Input 13, to be set from CAP tool
EVxx-NAME14	19 characters string	User name of signal connected to Input 14, to be set from CAP tool
EVxx-NAME15	19 characters string	User name of signal connected to Input 15, to be set from CAP tool
EVxx-NAME16	19 characters string	User name of signal connected to Input 16, to be set from CAP tool
EVxx-INTERVAL	0-60 s	Interval time for cyclic sending of data, to be set from CAP tool
EVxx-BOUND	0=Off, 1=On	Connected to other terminals on the network, to be set from CAP tool

38 Disturbance Report

38.1 Summary of application

The Disturbance Report is intended to provide relevant information in case of disturbances. The information is mainly intended for two categories of personal and is sorted accordingly. Operational personal need quick overview for fast decision making, while the relay engineer and maintenance people require more detailed information and can take more time for evaluation and maintenance planning.

The Disturbance Report is a common name for several facilities to supply information on disturbances.

The functions included are:

- General disturbance information
- Indications
- Event recorder
- Trip values
- Disturbance recording

Part of the information is presented on the built-in HMI. All information is accessible via SMS and SCS.

38.2 Information on the built-in HMI

The following information is available for each disturbance, that is stored in the terminal:

- Date and time
- Trig signal
- Indications
- Trip values

38.3 Information retrieved with SMS or SCS

A Disturbance Overview, which is a summary of all the recorded disturbances, is available. The overview contains:

- Disturbance index
- Date and time
- Trig signal, that has activated the recording

Upon selection one of the disturbances more detailed information is available for each disturbance.

The disturbance recording recorded by the disturbance recorder function can be retrieved to a PC and the analogue and digital signals can be visualized on the screen and printed out.

38.4 Summary of function

The Disturbance Report function collects and stores information about disturbances. 48 binary signals and ten analogue signals can be connected to the function. The recording starts when one of the triggers is activated. This means that no report will be generated unless there is a trigger activated. The triggers can be any of the binary inputs or threshold levels on any of the analogue inputs. The recording covers the following time intervals, which form part of the total recording time:

- pre-fault time
- fault time
- post fault time

The function can store up to 10 reports. The reports are stored in a non-volatile cyclic memory and the FIFO principle is employed.

The following functions are included in the disturbance report function:

- General disturbance information

This is a summary of and overview of the recorded disturbances. The content may differ, depending on were it is presented. (Built-in HMI, SMS or SCS)

- Indications

This is a list of signals out of the selected maximum 48, that have been active during the fault time.

- Event recorder

The event recorder records all the status changes among the connected binary signals. The number of events is limited to 150 for each disturbance.

- Trip values

The function calculates the values of currents and voltages before and during fault. The values are presented as phase values with amplitude and argument.

- Disturbance recorder

The disturbance recorder records the analogue and digital channels that are connected to this function. For visualization the recording has to be transferred to a PC.

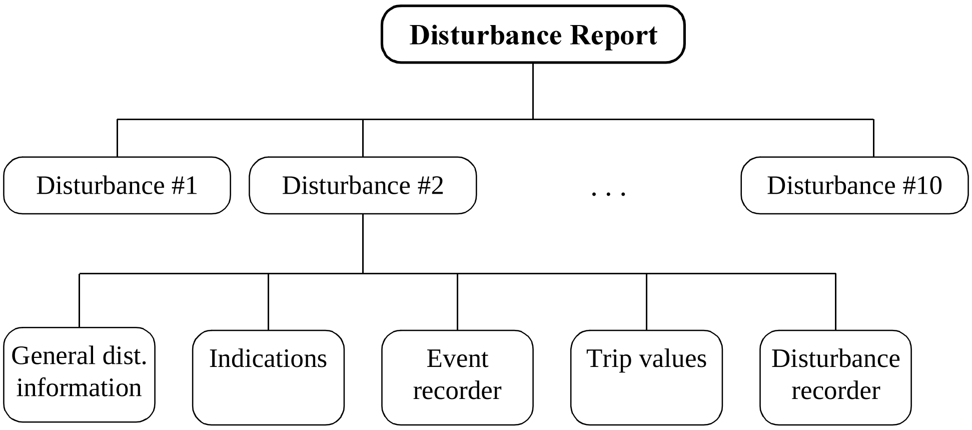


Fig. 112 Structure of the disturbance report function

38.5 Description of logic

38.5.1 Common functions

38.5.1.1 Recording times

A recorded disturbance is divided into three parts, a pre-fault period, a fault period and a post-fault period. The length of the pre-fault and post-fault periods can be configured by the user.

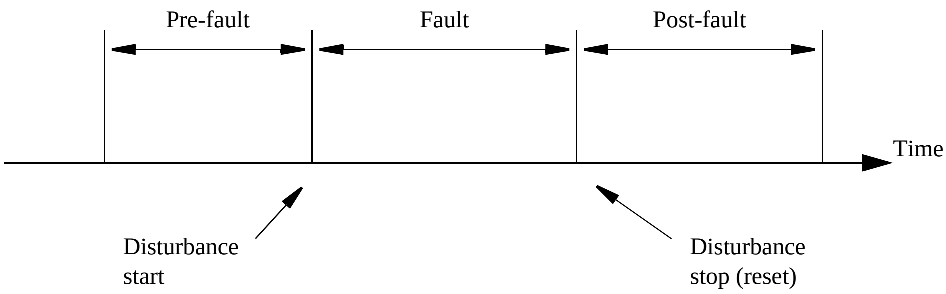


Fig. 113 Periods of a disturbance and their relations.

In addition to the limits of the pre-fault time (tPre) and post-fault time (tPost) the user can specify a limit time (tLim) that defines the maximum length of a disturbance recording from the fault occurrence (trig).Fig. 114 and Fig. 115 show the relations between the time limits for two different values of tLim.

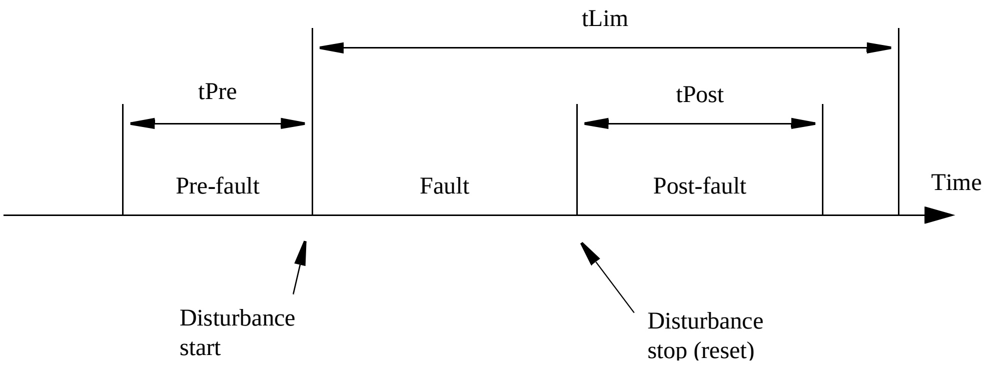


Fig. 114 Recording times relations.

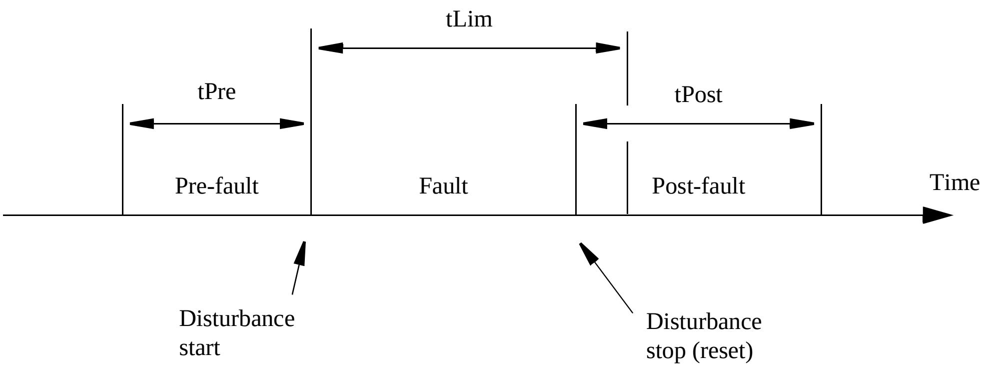


Fig. 115 Recording times relations.

38.5.1.2 Start and stop of recording

A recording of a disturbance can be started by any of the binary input signals or by analogue trig conditions that can be specified by the user. When a disturbance recording is triggered, the pre-fault buffer is locked and the data is stored in the fault buffer for as long as the start condition persists. If the trigger should not reset within an expected time interval, the total recording time is limited by a maximum limit time, tLim. When tLim is reached the active disturbance recording is terminated and the recording continues in a new cyclic buffer. The original trigger and all other triggers that were active when tLim was reached, must first be reset before they can cause a new start condition. Any other trigger, except for the non-reset triggers, can start a new disturbance recording when the current recording is terminated, either by reaching tLim or after a reset of the start condition.

Observe that the disturbance report function can not respond to any new trig condition, during a recording of a disturbance. The whole active disturbance recording must be finished before a new disturbance can be recorded.

However, there is an option (setting parameter PostRetrig) that can be set to allow a new recording to be started during the post-fault period of a recording. In this case the current recording will be terminated when the new trigger is activated. A new recording will start, but without any pre-fault time recording. If this re-trig function during post-fault option is not enabled, a new recording will not start until the post-fault period is terminated (by tPost or tLim).

The start and stop of a recording is time-tagged with date and time with a resolution of 1 ms.

38.5.1.3 Inputs

The disturbance report function can accept up to 48 binary and up to 10 analogue signals.

38.5.1.4 Trig signals

Three types of triggers can be used to start the disturbance report function:

- Binary signal trig
- Analogue signal trig (over and under trig functions)
- Manual trig

38.5.1.5 Binary signal trig

Any of the selected binary input signals can be used to trigger the disturbance report. The trig signals can be selected to trig either on a transition from low to high level or on a transition from high to low level.

38.5.1.6 Analogue signal trig

Analogue signals can only be used, when the disturbance recorder function is installed. Furthermore analogue triggers can only be used for recorded signals.

The analogue input signals can be used to generate trig signals with over and under trig functions. The over trig function compares the value of the analogue signal with a maximum limit value. If the analogue value is above the limit the report function is trigged. In the under trig operation the analogue input value is compared to a minimum limit value and if the signal is below the limit, the report function is trigged. The limits (over and under trig limits) are user configurable for each selected analogue signal. The limits are ratios and are relative a nominal value of the input signal. The nominal values of the input signal are set by the user for each analogue input signal. Every analogue input signal can be used to generate trig signals either using the over function or the under function or both. The analogue trigger functions have an operating time of approximately one cycle.

38.5.1.7 Manual trig

The disturbance report function can also be initiated manually.

38.5.2 Sampling rate

The sampling rate the data storage is 20 samples per cycle, i.e. 1000 Hz for a 50 Hz network and 1200 Hz for a 60 Hz network.

38.5.3 Memory capacity

The memory capacity for the disturbance report function is 10 disturbances. This means that events, indications and trip values for ten latest disturbances are stored in a non-volatile memory. The memory employs the FIFO principle, i.e. when the memory is full, data for the oldest disturbance will be overwritten.

The memory capacity for the disturbance recorder function is dealt with under that function.

38.5.4 Indications

As indications are the binary signals, that were active during the fault time, considered. These signals are listed without any time tagging and stored in a signal list.

38.5.5 Event recorder

All changes of status of the maximum 48 binary input signals are time tagged with date and time with a resolution of 1 ms. The capacity is maximum 150 events for each disturbance.

38.5.6 Trip values

This function calculates the pre-fault and fault values. For calculation of the pre-fault values the first cycle in the recording is used. The calculation of the fault values is based on the cycle immediately following the trig signal. Both pre-fault and fault values are presented as RMS phase values with amplitude and argument.

38.5.7 Disturbance recorder

38.5.7.1 Storage and data format

When a recording is made, the recorded data is stored temporarily in an area for uncompressed data. Data compression is run as a background task.A compression algorithm with 100% recording and upload data accuracy is used. This gives a data compression factor of maximum two times, depending on the shape of the analogue signal wave form. The compression factor for the binary signals depends on how often signal transitions occur and how the signals are grouped when the compression is performed.The compression time is approximately twice the length of the recording. When the compression is completed the data is stored in an other area of the non-volatile memory.

A disturbance recording is stored as two files, a header file and a data file. The header file has information about the following:

- Station name, object name and unit name
- Recording sequence number
- Date and time for the trig of the disturbance
- Pre-fault and fault RMS values
- Signal identifier for the selected binary and analogue signals
- Activated trigger and its value
- Status of analogue inputs including trig functions
- Status of binary input signals
- Recording times
- Sampling rate

The RMS values for currents and voltages during the pre-fault and fault periods are calculated in the terminal.

The data file consists of the compressed data from the recorded analogue and digital signals.

The data format of the header and data files that will be used is the REVAL format, REVAL.HDR and REVAL.DAT. The two files can be retrieved and visualized with RECOM and REVAL.

Since data for one disturbance is collected in different parts of the terminal, all recordings must be erased when parameters are changed.

38.5.7.2 Memory capacity

In the memory area for uncompressed data maximum four recordings with maximum time settings can be stored.

The memory capacity for storage of compressed data is approximately 10 seconds for recordings with full capacity, i.e. 48 binary signals and 10 analogue signals.

38.6 Function block

The following function blocks can be visualized in the CAP configuration tool:

- 1 no block for general functionality
- 3 nos blocks, each for 16 binary inputs
- 10 nos blocks, each for one analogue input

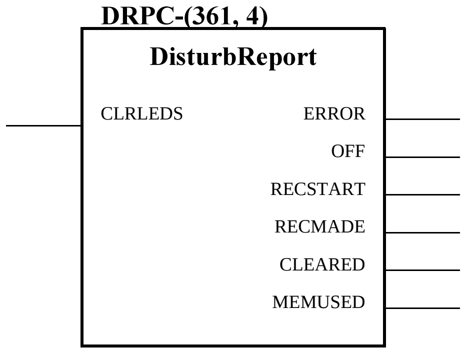


Fig. 116 General function block

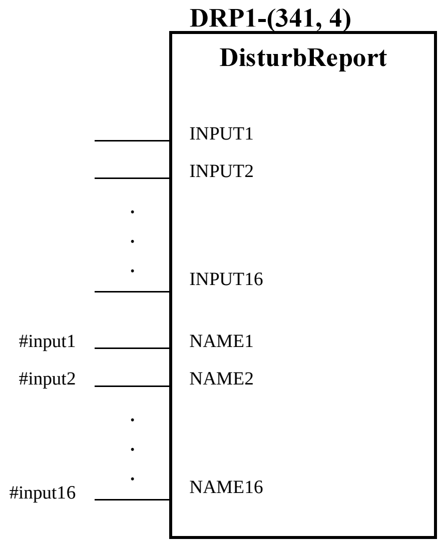


Fig. 117 Function block 1 for binary inputs

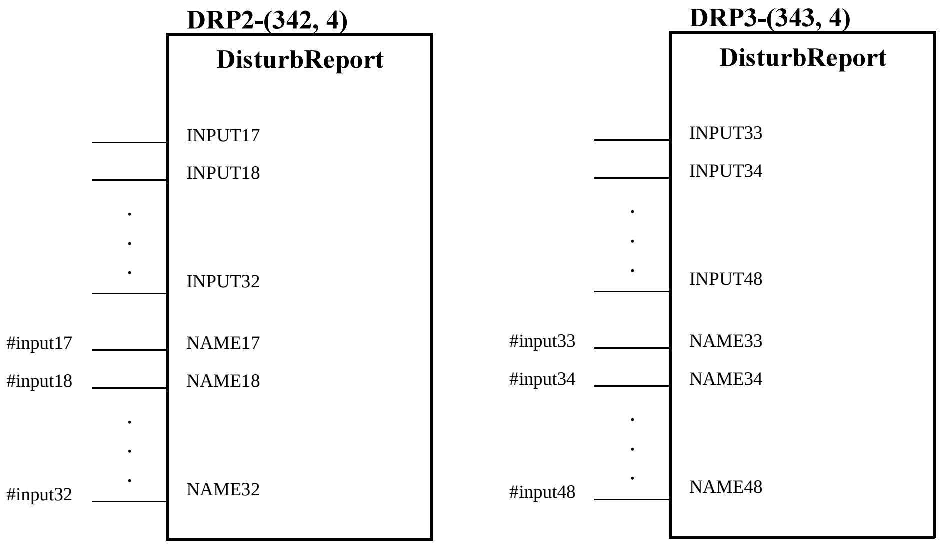


Fig. 118 Function block 2 and 3 for binary inputs

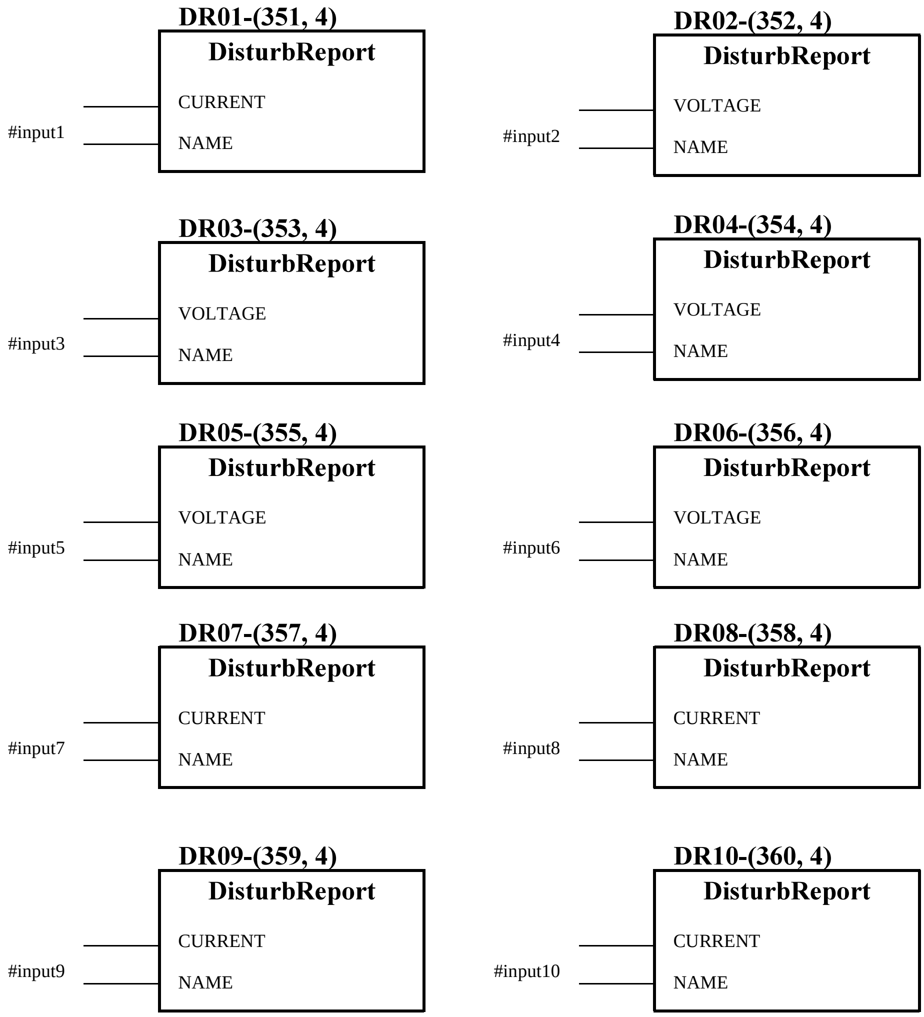


Fig. 119 Function blocks for analogue inputs

38.7 Input and output signals

38.7.1 Input signals

The following signals and parameters are inputs to the disturbance report object. Only the analogue input parameters are specific for the disturbance recorder and the trip values function and are thus only available when any of these options is installed.

- CLRLEDS This binary signal is used to clear the built-in HMI LEDs.
- INPUTx These input signals are used to select the binary input signals that will be recorded. The signals can be any binary signal in the terminal, binary input signals or internally generated within the terminal.
- NAMEx User assigned name of the binary input signal.
- VOLTAGE This input signal is used to select a voltage signal that will be recorded by the function. The selected signal cannot be generated, e.g. a calculated value, in the RET521 terminal and must be connected directly to a voltage input of the terminal.
- CURRENT This input signal is used to select a current signal that will be recorded by the function. The selected signal cannot be generated, e.g. a calculated value, in the RET521 terminal and must be connected directly to a current input of the terminal.
- NAME User assigned name of the analogue input signal.

38.7.2 Output signals

The following signals are output signals of the disturbance report function block.

- OFF Disturbance report operation during normal condition is turned off.
- RECSTART This signal is set when a disturbance recording has been started, i.e. a recording is currently performed.
- RECMADE This output signal is set when a disturbance recording has been completed, i.e. a disturbance has been recorded, compressed and stored to a file in non-volatile memory.
- CLEARED This signal is set when all recorded disturbances in the disturbance report are cleared.
- MEMUSED This output signal is set when the memory usage is over 80% of the available memory assigned to the disturbance recorder function.
- ERROR This output signal is set to indicate an internal error of the disturbance report function.

38.8 Setting parameters and ranges

38.8.1 Description of parameters

38.8.1.1 General

- Operation Defines if the disturbance report function is turned on or off.
- PostRetrig Defines if a new recording can be started during the post-fault period of a recording or not.
- SequenceNo Sequence number of the recorded disturbance.
- tPre Defines the pre-fault recording time, i.e. the length of the recorded time period prior to the start of a disturbance recording.
- tPost Defines the post-fault recording time, i.e. the length of the recorded time period after the trig condition has reset.
- tLim Defines the maximum length of a disturbance. The pre-fault period is not included in this limit.
- SamplingRate Defines the rate used to sample the binary and analogue input signals.
- FreqSource Defines which analogue input signal that should be input to the line frequency calculation of the trip values function. This signal will also be used as reference when the phase angles are calculated.

Description	Name	Unit	Range	Step	Default
Operation	Operation	0 = Off 1 = On	0 - 1	1	1
Retrig during post fault	PostRetrig	0 = Off 1 = On	0 - 1	1	0
Sequence number	SequenceNo	-	0 - 255	1	0
Pre-fault recording time	tPre	s	0.05 - 0.30	0.01 s	0.05 s
Post-fault recording time	tPost	s	0.1 - 5.0	0.1 s	0.5 s
Limit time	tLim	s	0.5 - 6.0	0.1 s	1.0 s
Sampling rate	Samplin-gRate	Hz	1000/1200	-	1000/1200
Line frequency source	FreqSource	-	0 - 10 [1)]	1	0

1) Function block number for analogue channels (DR01........DR10)

38.8.1.2 Binary signals

- TrigOperation Defines if the binary input signal may trig the disturbance recorder.
- TrigLevel Defines if the binary trig operation will trig on a transition from low to high or on a transition from high to low.
- IndicationMask This parameter defines if the binary signal will be shown on the built-in HMI when the indications are scrolled (auto indications).
- SetLED Defines if the selected binary signal will set the red LED of the built-in HMI when active.

Description	Name	Unit	Range	Step	Default
Trig operation	TrigOperation	0 = Off 1 = On	0 - 1	1	0
Trig level	TrigLevel	0 = Trig on 1 1 = Trig on 0	0 - 1	1	0
HMI indication mask	IndicationMask	0 = Masked 1 = Show	0 - 1	1	0
Set red led	SetLED	0 = Off 1 = On	0 - 1	1	0

38.8.1.3 Analogue signals

- Operation Defines if the connected analogue input signal will be recorded during a disturbance.
- NominalValue Defines the nominal value of the input signal. This value is used to calculate the absolute limits used by the under and over trig functions.
- <TrigOperation Defines if the analogue signal may generate an under trig condition used to start a disturbance recording.
- >TrigOperation Defines if the analogue signal may generate an over trig condition used to start a disturbance recording.
- <TrigLevel Under trig level, relative the rated value of the analogue input signal.
- >TrigLevel Over trig level, relative the rated value of the analogue input signal.

All the binary and analogue settings are set for each selected input signal, i.e. every signal has its own unique settings according to above. The general settings above apply to a single disturbance recording.

Description	Name	Unit	Range	Step	Default
Operation	Operation	0 = Off 1 = On	0 - 1	1	0
Nominal value	NominalValue	kV (U) A (I)	0.0 - 999999.9	0.1	1000
Under trig operation	<TrigOperation	0 = Off 1 = On	0 - 1	1	0
Over trig operation	>TrigOperation	0 = Off 1 = On	0 - 1	1	0
Under trig level	<TrigLevel	%	0 - 200	1%	50%
Over trig level	>TrigLevel	%	0 - 5000	1%	200%

38.9 Service value report

Table 122:

Parameter:	Range:	Step:	Description:
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active

Table 122:

Parameter:	Range:	Step:	Description:
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
Memory Used	0 - 100		Memory used[a]

a. Rounded up to nearest integer.

39 Monitoring of DC analogue measurements

39.1 Application

Alarm limits can be set and used as triggers, i.e. to generate trip signals. The software functions to support presentation of measured values are always present in the terminal. In order to retrieve actual values, however, the terminal must be equipped with the appropriate hardware measuring module(s).

Use the DC monitoring function to measure and process signals from different measuring transducers. Many devices used in process control uses low currents, usually in the range 4-20 mA or 0-20 mA to represent low frequency, near dc signals. The terminal can be equipped with analogue inputs for such signals, function blocks MI11-MI16, in the mA range.

39.2 Function block

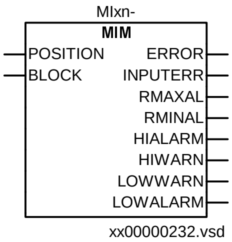


Fig. 120 A MIM module (mA input module) has six input channels. Each channel has a function block, MIxn-, where x=1 (for a RET terminal) is the number of the MIM module, and n=(1-6) is the number of the channel.

39.3 Input and output signals

Table 123: Input signals for the MIM (MIxn-) function block

Signal	Description
POSITION	I/O module slot position connector. Only present in first instance of block for each present input module.
BLOCK	Block value updating

Table 124: Output signals for the MIM (MIxn-) function block

Signal	Description
ERROR	Module fail. Only present in first instance of block for each present input module.
INPUTERR	Input error
RMAXAL	Upper range limit reached
HIALARM	Input high alarm limit reached
HIWARN	Input high warning limit reached
LOWWARN	Input low warning limit reached
LOWALARM	Input low alarm limit reached
RMINAL	Lower range limit reached

39.4 Setting parameters

Setting table for a generic mA input module MIM

Table 125: Module parameter

Parameter	Range	Default	Unit	Description
SampRate	5-255 Step: 1	5	Hz	Sampling Rate for mA Input Module x

Table 126: Input n, where n = 1 - 6

Parameter	Range	Default	Unit	Description
Name	0-13	MIx*n* -Value	Char	User defined name for input *n* in module x. String length up to 13 characters, all characters available on the HMI can be used
Operation	Off, On	Off	-	Input *n*
Calib	Off, On	On	-	Set to ’On’ to use production calibration for Input *n*
ChSign	Off, On	Off	-	Set to ’On’ if sign of Input *n* shall be changed
Unit	0-5	Unit *n*	Char	State a 5 character unit name for Input *n*
Hysteres	0.0-20.0 Step: 0.1	1.0	mA	Alarm hysteresis for Input *n*
EnAlRem	Off, On	Off	-	Immediate event when an alarm is removed for Input *n*
I_Max	-25.00-25.00 Step: 0.01	20.00	mA	Max current of transducer to Input *n*
I_Min	-25.00-25.00 Step: 0.01	4.00	mA	Min current of transducer to Input *n*
EnAlarm	Off, On	Off	-	Set to ’On’ to activate alarm supervision for Input *n*
HiAlarm	-25.00-25.00 Step: 0.01	19.00	mA	High Alarm level for Input *n*
HiWarn	-25.00-25.00 Step: 0.01	18.00	mA	High Warning level for Input *n*
LowWarn	-25.00-25.00 Step: 0.01	6.00	mA	Low warning level for Input *n*

Parameter	Range	Default	Unit	Description
LowAlarm	-25.00-25.00 Step: 0.01	5.00	mA	Low Alarm level for Input *n*
RepInt	0-3600 Step: 1	0	s	Time between reports for Input *n*
EnDeadB	Off, On	Off	-	Enable amplitude dead band supervision for Input *n*
DeadBand	0.00-20.00 Step: 0.01	1.00	mA	Amplitude dead band for Input *n*
EnIDeadB	Off, On	Off	-	Enable integrating dead band supervision for Input *n*
IDeadB	0.00-1000.00 Step: 0.01	2.00	mA	Integrating dead band for Input *n*
EnDeadBP	Off, On	Off	-	Enable periodic dead band reporting Input *n*
MaxValue	-1000.00-1000.00 Step: 0.01	20.00	-	Max primary value corr. to I_Max, Input *n*. It determines the maximum value of the measuring transducer primary measuring quantity, which corresponds to the maximum permitted input current I_Max
MinValue	-1000.00-1000.00 Step: 0.01	4.00	-	Min primary value corr. to I_Min, Input 1. It determines the minimum value of the measuring transducer primary measuring quantity, which corresponds to the minimum permitted input current I_Min

39.5 Technical data

Table 127: mA measuring function (MIM)

Function	Setting range	Accuracy
mA measuring function	+/- 5, +/- 10, +/- 20 mA 0-5, 0-10, 0-20, 4-20 mA	+/- 0.1% of set value +/- 0.005 mA
Max current of transducer to input	(-25.00 to +25.00) mA in steps of 0.01	
Min current of transducer to input	(-25.00 to +25.00) mA in steps of 0.01	
High alarm level for input	(-25.00 to +25.00) mA in steps of 0.01	
High warning level for input	(-25.00 to +25.00) mA in steps of 0.01	
Low warning level for input	(-25.00 to +25.00) mA in steps of 0.01	
Low alarm level for input	(-25.00 to +25.00) mA in steps of 0.01	
Alarm hysteresis for input	(0-20) mA in steps of 1	
Amplitude dead band for input	(0-20) mA in steps of 1	
Integrating dead band for input	(0.00-1000.00) mA in steps of 0.01	

40 Remote communication (RC)

40.1 Summary of application

The remote communication can be used for different purposes to enable better access to the information stored in the terminals.

The remote communication can be used with a station monitoring system (SMS) or with computerized substation control system (SCS). Normally, SPA communication is used for SMS and LON communication for SCS. SPA communication is also applied when using the front communication port, but for this purpose, no special Remote communication function is required in the terminal. Only the software in the PC and a special cable for front connection is needed.

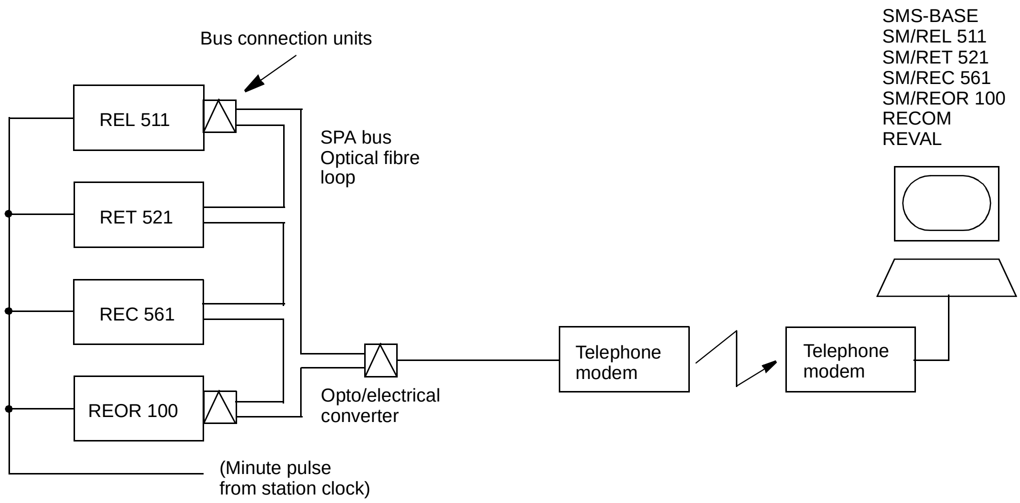


Fig. 121 Example of SPA communication structure

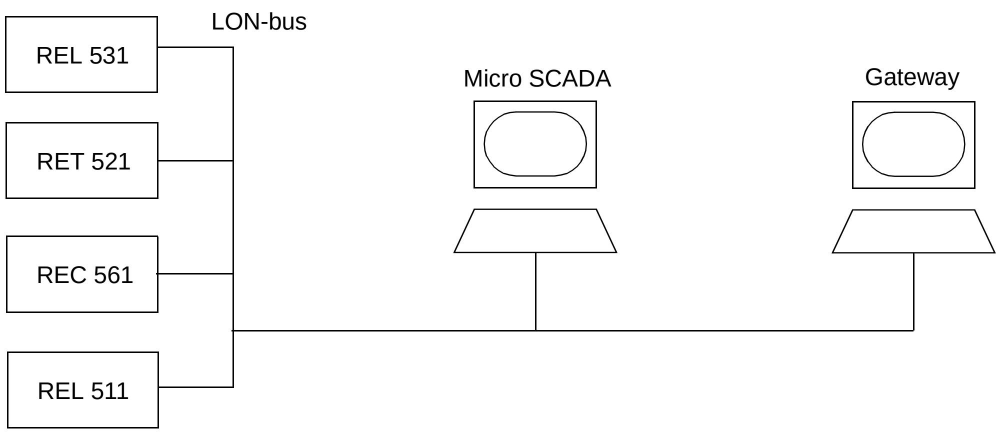


Fig. 122 Example of LON communication structure

40.2 Summary of function

All remote to and from the terminal (including front communication) uses either the SPA bus V 2.4 protocol or the LonTalk protocol.

The remote communication uses optical fibres for transfer of data within a station. The principle of two independent communication ports is used. For this reason, two serial ports for connection of optical fibres are optionally available in the terminal, one for LON communication and one for SPA communication.

40.2.1 SPA operation

The SPA protocol is an ASCII based protocol for serial communication. The communication is based on a master - slave principle, where the terminal is the slave and the PC is the master. Only one master can be applied on each application. A program is needed in the master computer for interpretation of the SPA bus codes and for translation of the settings sent to the terminal. This program is called PST. For configuration CAP program is required.

40.2.2 LON operation

The LON protocol is specified in the LonTALKProtocol Specification Version 3 from Echelon Corporation. This protocol is designed for communication in control networks and is a pier-to-pier protocol where all the devices connected to the network can communicate with each other directly.

40.3 Description of logic

The remote communication uses optical fibres for transfer of data within the station. For this purpose two serial ports for connection of optical fibres are optionally available on the rear of the terminal. One is intended for SPA communication and the other for LON communication. The principle of two independent communication channels is used.

40.3.1 SPA communication

When communicating locally with a PC in the station using the rear SPA port, the only hardware needed for a station monitoring system is:

- Optical fibres
- Opto/electrical converter
- PC

When communicating remotely with a PC using the rear SPA port, the same hardware plus a telephone modem is required.

Depending on the functional requirements all or part of the following software packages can be used for SPA communication:

- CAP 540, configuration and programming tool package.
- RECOM, program for collection of disturbance files. Not required for front communication.
- REVAL, program for visualization of disturbance data. Communication controlled by RECOM.

There are two parameters, that can be set for remote communication. These two are the “slave number” and “baud rate”. These can for obvious reasons only be set on the built-in HMI.

40.3.2 LON communication

The hardware needed for applying LON communication depends on the application, but one very central unit is the LON Star Coupler and optical fibres connecting the star coupler to the terminals.

The LNT, LON Network Tool is used to set the communication parameters. This is a software tool, that is applied as one node on the LON bus.In order to communicate via LON, the terminals need to know which node addresses the other connected terminals have and which network variable selectors should be used. This is organized by the LNT. The node address is transferred to the LNT via the built-in HMI or the LNT can scan the communication network for new nodes.

The speed of the communication is set to default 1,25 Mbits/s. This can be changed by the LNT. If the communication stops, caused by setting of illegal communication parameters or by other disturbance, the parameters can be re-set to default values on the built-in HMI.

40.4 Setting parameters and ranges

40.4.1 SPA communication

Parameter:	Setting range:	Description:
Rear:		
SlaveNo	(1 - 899)	SPA-bus identification number
BaudRate	300, 1200, 2400, 4800, 9600, 19200, 38400 Baud	Communication speed
RemoteChActgrp	Open, Block	Open=Access right to change between active groups (both rear ports)
RemoteChSet	Open, Block	Open=Access right to change any parameter (both rear ports)
Front:		
SlaveNo	(1 - 899)	SPA-bus identification number
BaudRate	300, 1200, 2400, 4800, 9600, 19200, 38400 Baud	Communication speed

40.4.2 LON communication

There are a number of session timers which can be set via the built-in HMI.These settings are only for advanced users and should only be changed after recommendation from ABB Automation Products AB.

Table 128: Session timers

Parameter	Default value	Description
SessionTmo	20s	Timeout value for the session
RetryTmo	2000 ms	Triggers a retransmission of the message if the message or ACK/NACK is missing when time is out.
IdleAckCycle	5s	Periocity for cyclic idle channel alive transmissions and retransmission of ACK when lost.
BusyAckTmo	300ms	ACK delay time upon received message. Sender can bypass the delay by flagging a message for immediate ACK.
ErrNackCycle	500ms	Periocity value for cyclic NACK transmission during network congestion

The chapter “Design description”

This chapter describes the protection terminal hardware design and each module. This chapter also contains terminal diagrams and technical data.

HW-description RET 521 313

Hardware design 313

Hardware architecture 313
Hardware modules 313
Optional modules 314

Technical data 315

Block diagram 317

Terminal diagrams 319

Hardware and data 319
RET 521 terminal diagram 320
DC-switch 321
Analogue input module 322
Binary in/out module 325
Binary in/out module with test switch RTXP 24 internal star-point 326
Binary in 16 module 327
Binary out module 328
Binary out module with test switch RTXP 24 internal star-point.................. 329
mA input module 330

HW-modules 331

Numerical module (NUM) 331

Hardware design 331
Technical specifications 331
Block diagram 332

Compact backplane module (CBM) 333

Hardware design 333
Technical specifications 333
Block diagram 335

Combination Extension backplane Module (CEM) 335

Hardware design 335
Technical specifications 336
Block diagram 337

Power Supply Module (PSM) 337

Hardware design 337
Block diagram 338

Analogue input module (AIM)...339

Hardware design 339
Technical specifications 339
Transformer board 339
A/D-conversion board 340
Block diagram for the A/D-conversion board 340

mA input module (MIM)...340

Hardware design 340
Technical specifications 341
Block diagram 341

Binary input module (BIM)...342

Hardware design 342
Technical specifications 343
Block diagram 344

Binary output module (BOM)...345

Hardware design 345
Technical data...345
Block diagram 346

Binary In/Out Module (IOM) 346

Hardware design 346
Technical data...347
Block diagram 347

HW-description RET 521

1 Hardware design

The RET521 follows the 6U Eurocard industry mechanical standard with a passive backplane and a number of slots. The backplane supports two kinds of modules, standard CompactPCI modules and specific ABB Automation Technology Products AB modules based on the CAN bus.

All modules are designed for low power dissipation (no fans), EMC safety (both immunity and emission) and good environmental resistance. That gives high reliability and safe system also under disturbed and rugged conditions.

1.1 Hardware architecture

RET 521 consists of a number of different modules. These modules communicate through the PCI bus or the CAN bus. The PCI bus is used for modules which need extra high transfer rate. Modules with low and medium data rate use the CAN bus.

The local HMI unit communicates directly with the NUM module through two serial channels. Remote HMI is connected via the SPA bus or the LON bus.

1.2 Hardware modules

The basic configuration of the RET 521 consist of the following modules:

- CBM, Combined Backplane Module. The backplane has 8 slots for CompactPCI modules and 4 slots for specific ABB Automation Technology Products AB modules. One slot is designed for the power supply module.
- CEM, Combination Extension Backplane Module. The CEM is an addition to the CBM and is mounted on the CBM module. All communication with the RCAN based ABB printed circuit boards are handled inside this module.
- AIM, Analog Input Module. CompactPCI module with 10 high performance analogue input channels. The module consists of transformers, analogue to digital converters and a signal processor. Main functions in the software are:
  - time stamping of all values
  - filtering and calibration adjustments of analog inputs
  - self supervision

- NUM, Numerical Module. Main CPU module based on a high performance. Fits into the specific system slot in the backplane. The module may carry a mezzanine card, according to the PMC (PCI Mezzanine Card) standard, see SLM module. The software system is running under a real time operating system. Main functions in the software are:
  - administration of the CompactPCI bus
  - administration of the CAN bus
  - supervision of all modules included in the rack
  - control error handling
  - control the I/O system
  - handle local HMI
  - handle front LED-HMI
  - handle remote HMI (communication via SPA and LON bus)
  - RET521 function execution
- PSM, power supply module. DC/DC converter that support the electronics with +/-12V, +5V and +3,3V. The module can provide up to 50W. Supervision of all voltages are implemented. The module includes one relay output for the “Internal Fail“ signal.
- HMI, human machine interface. Local HMI panel located at the front of the RET 521 terminal.
- LED-HMI with 18 three colour leds for indication purposes. LED-HMI panel located at the front of the RET 521 terminal.

1.2.1 Optional modules

- SLM, Serial channel and LON channel Module. A mezzanine card for the NUM module, follows the PMC standard. Communication module with two optical interfaces. One for SPA bus and one for the LON bus.
- BIM, Binary input module. CAN based module with 16 optical isolated binary inputs. Main functions in the software are:
  - time stamping of all events
  - filtering of binary inputs
  - possibility to have any input as time synchronizing input using galvanic minutepulse
  - self supervision
- BOM, Binary output module. CAN based module with 24 relay outputs. 24 single-output relays or 12 freely contacts for “select before execute” output relays. Main functions in the software are:
  - time stamping of all event
  - self supervision

- IOM, Input and output module. CAN based module with 8 optical isolated binary inputs and 12 relay outputs. Main functions in the software are:
  - time stamping of all events
  - filtering of binary inputs
  - possibility to have any input as time synchronizing input using galvanic minutepulse
  - self supervision
- MIM, Milliampere input module. CAN based module with 6 optically isolated low speed analog inputs. All channels are factory calibrated. Main functions in the software are
  - time stamping of all events
  - filtering and calibration adjustments of analog inputs
  - programmable alarm levels
  - self supervision

2 Technical data

Table 1: Electromagnetic compatibility (EMC), immunity tests

Test	Type test values	Reference standards
1 MHz burst disturbance	2,5 kV	IEC 60255-22-1, Class III
Electrostatic discharge Direct application	8 kV, air discharge 6 kV, contact discharge	IEC 60255-22-2, Class III
Fast transient disturbance	4 kV	IEC 60255-22-4, Class A
Surge immunity test	1-2 kV, 1,2/50 µs, high energy	IEC 60255-22-5
Power frequency immunity test	100-300 V, 50 Hz	IEC 60255-22-7, Class A
Power frequency magnetic field test	1000 A/m, 3 sec.	IEC 61000-4-8, Class V
Radiated electromagnetic field disturbance	10 V/m, (80-1000) MHz	IEC 60255-22-3
Radiated electromagnetic field disturbance	10 V/m, (80-1000) MHz, (1,4-2,0)GHz	IEC 61000-4-3, Class 3
Radiated electromagnetic field disturbance	10 V/m, 27, 80, 150, 450, 900 MHz	IEEE/ANSI C37.90.2
Conducted electromagnetic field disturbance	10 V (0,15-80) MHz	IEC 60255-22-6

Table 2: Electromagnetic compatibility (EMC), emission tests

Test	Type test values	Reference standards
Electromagnetic emission, radiated	30-1000 MHz	IEC 60255-25
Electromagnetic emission, conducted	0,15 - 30 MHz	IEC 60255-25

Table 3: Insulation tests

Test	Type test values	Reference standards
Dielectric test	2,0 kV ac 1 min	IEC 60255-5
Impulse voltage test	5 kV, 1,2/50 μs, 0,5 J	IEC 60255-5
Insulation resistance	> 100 Mohm at 500 V dc	IEC 60255-5

Table 4: CE-mark

Test	Reference standards
Immunity	EN 61000-6-2
Emissivity	EN 61000-6-4
Low voltage directive	EN 50178

Table 5: Mechanical tests

Test	Type test values	Reference standards
Vibration	Class I	IEC 60255-21-1
Shock and bump	Class I	IEC 60255-21-2
Seismic	Class I	IEC 60255-21-3

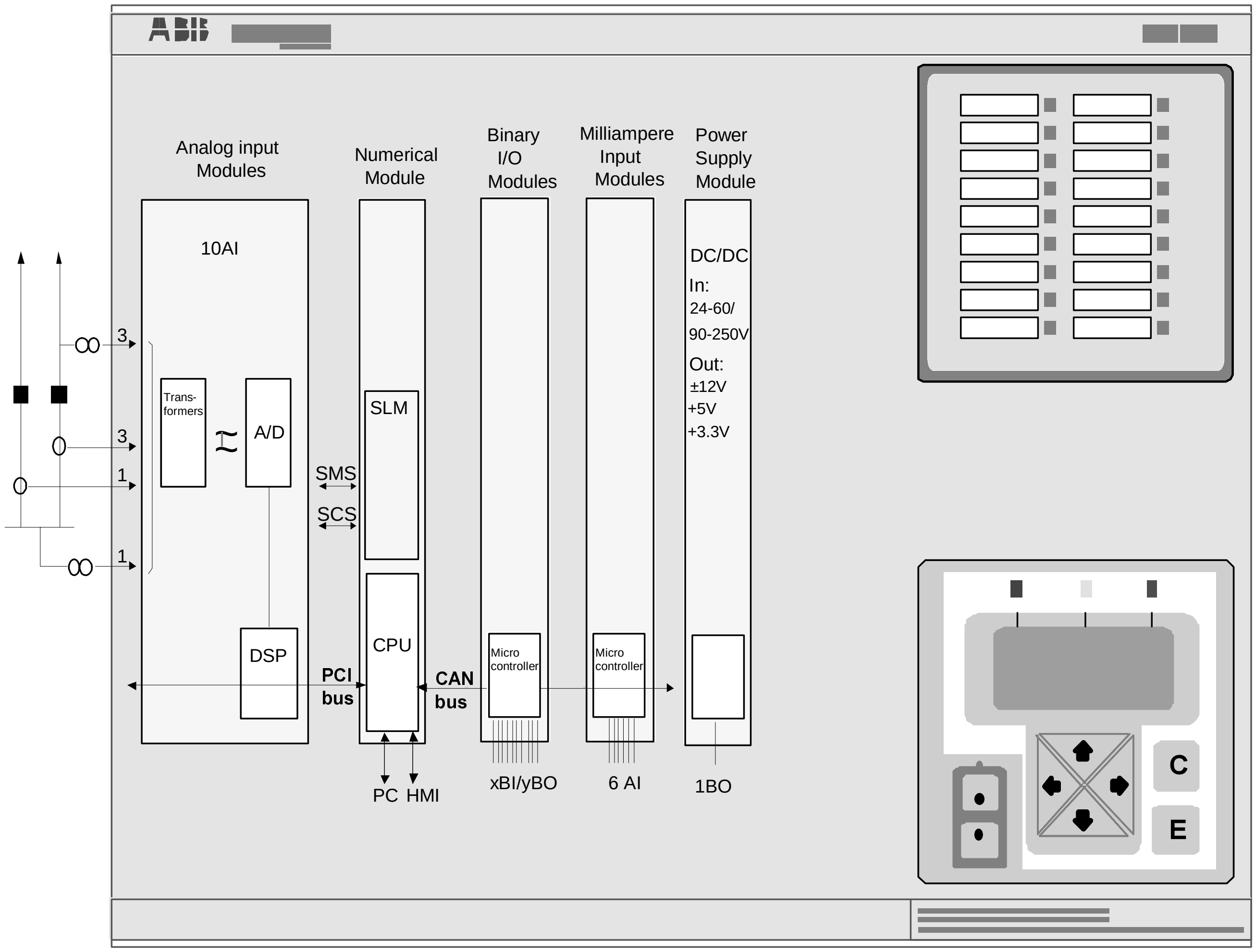
Table 6: Connection system

Connector type	Rated voltage	Maximum square area	Maximum load continuous	Maximum load 1 s
Voltage connectors	250 V AC	2,5 mm^2 2 x 1 mm^2	10 A	30 A
Current connectors	250 V AC	4 mm^2	20 A	500 A

Table 7: Additional general data

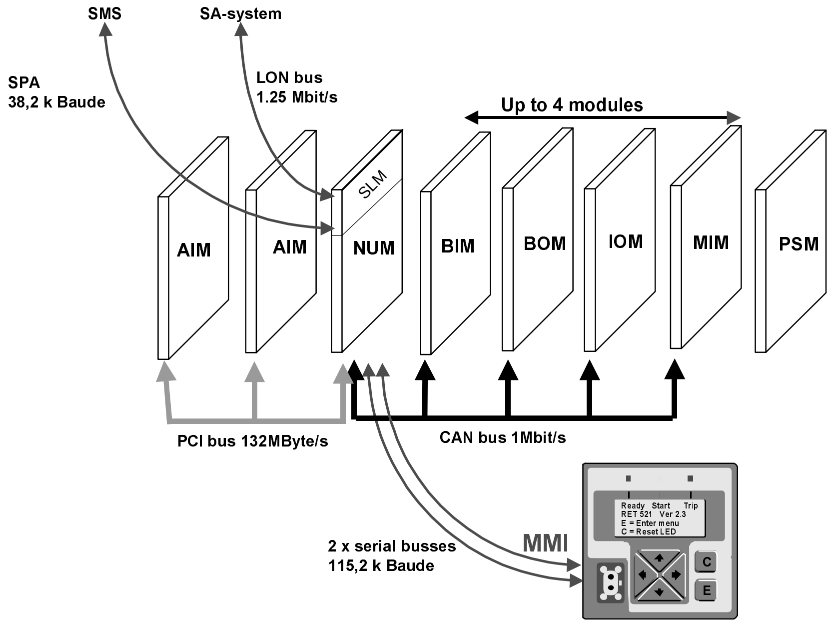
Operating temperature	-5°C to +55°C
Storage temperature	-40°C to +70°C
Dimensions Width Height Depth	 336 mm (3/4 of 19”) 6U = 266 mm 245 mm

3 Block diagram



en03000165.vsd

Fig. 1 Internal hardware structure of the RET521 platform

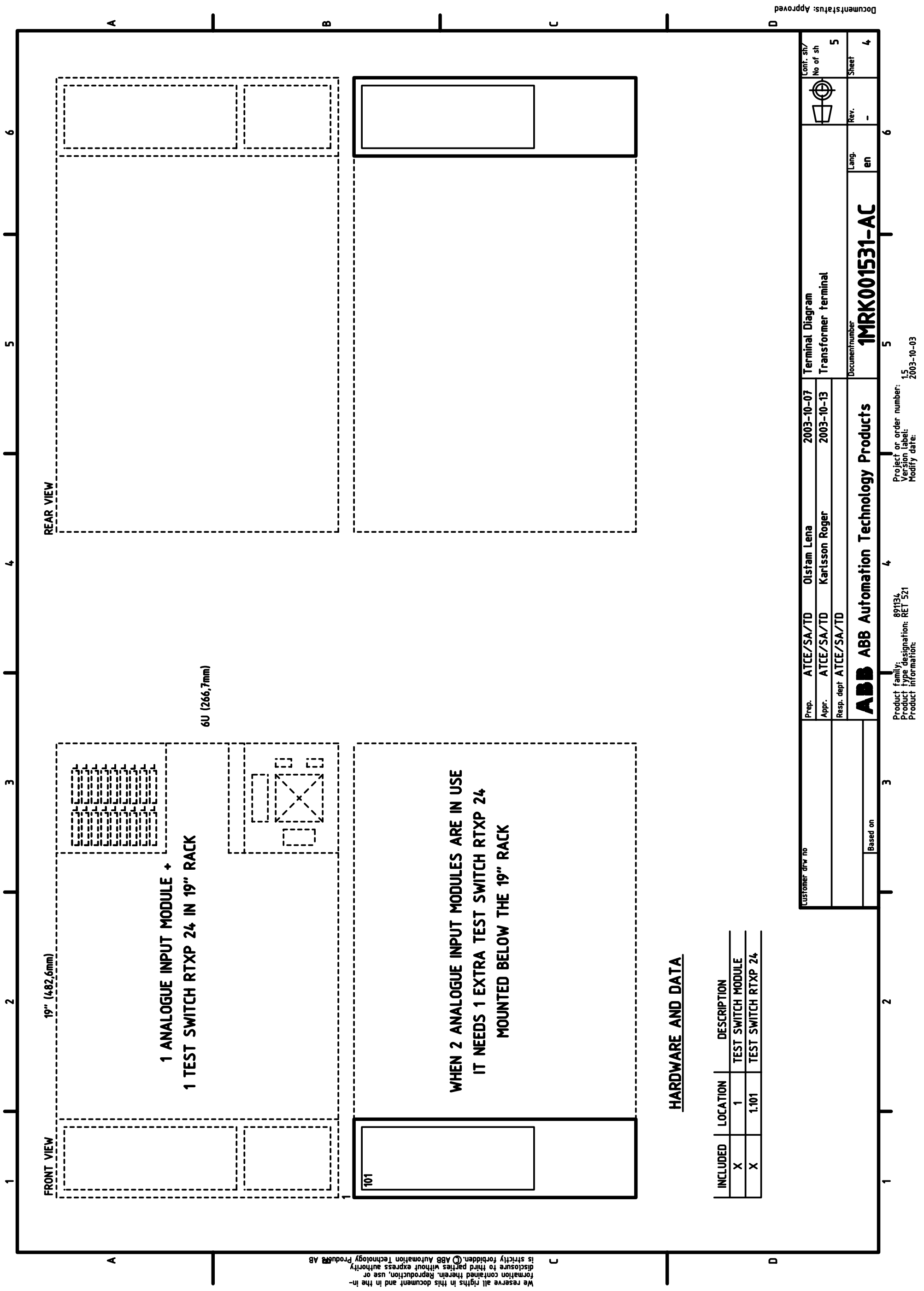


en01000100.vsd

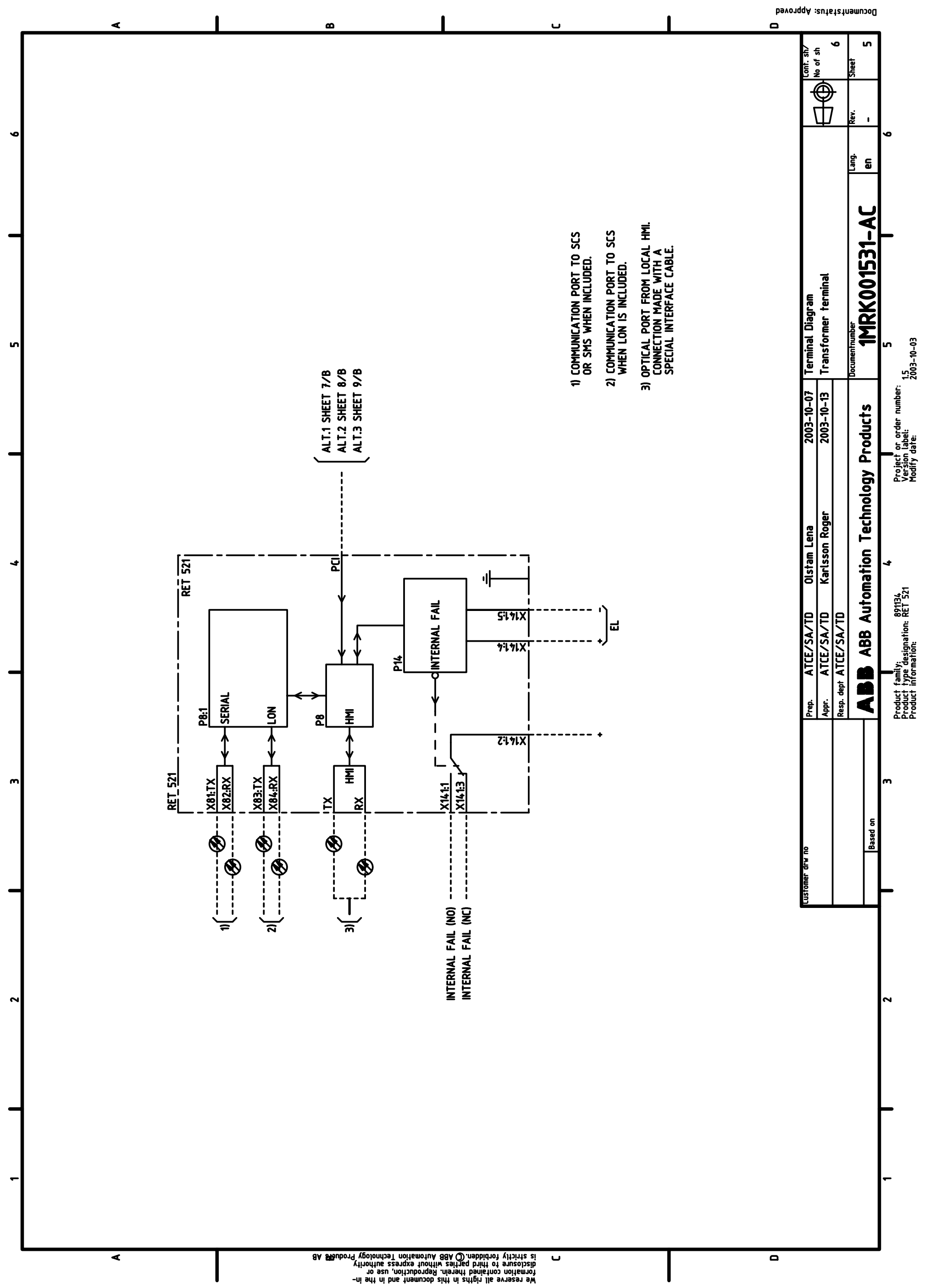
Fig. 2 Internal and external communications busses

4 Terminal diagrams

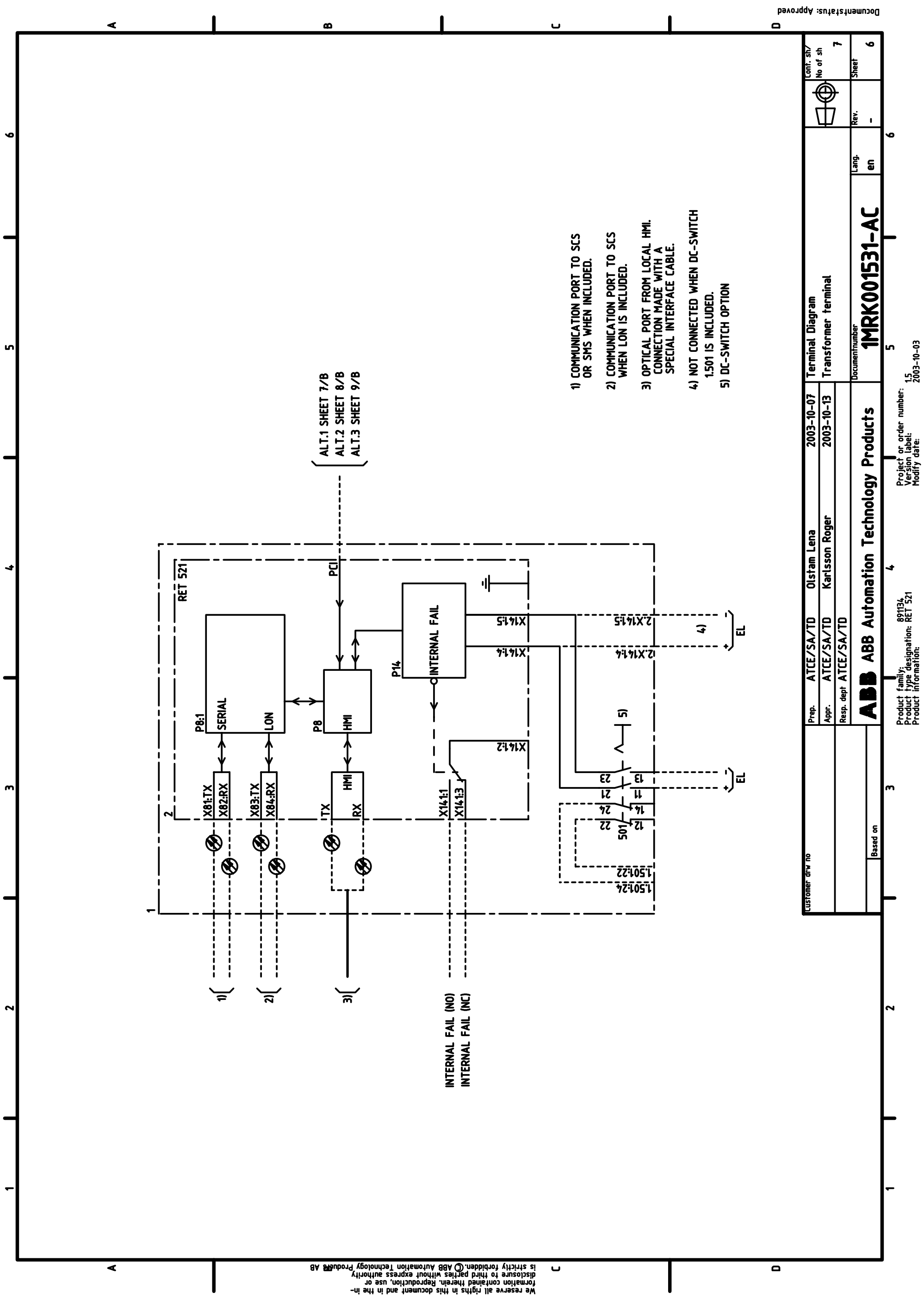
4.1 Hardware and data



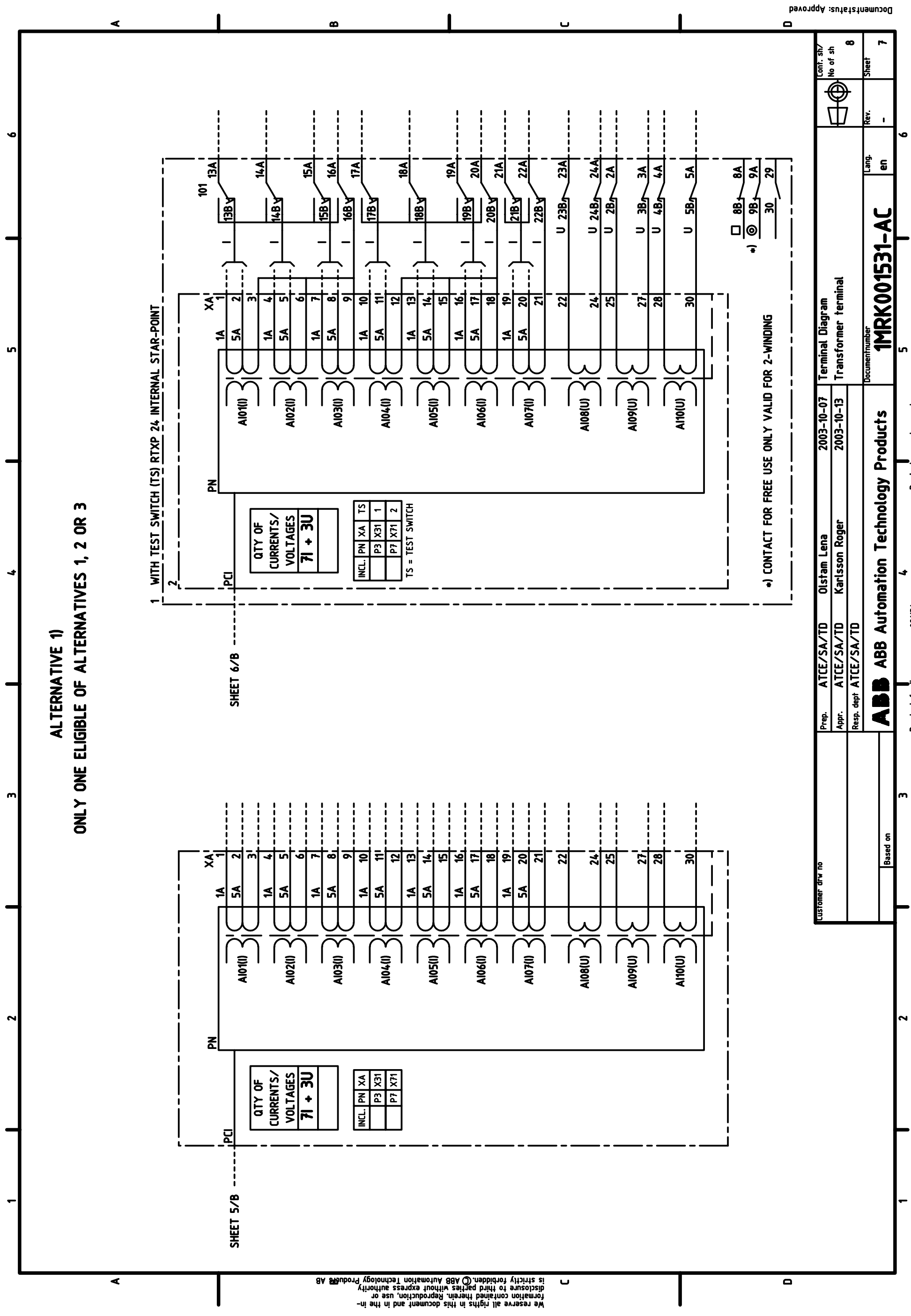
4.2 RET 521 terminal diagram



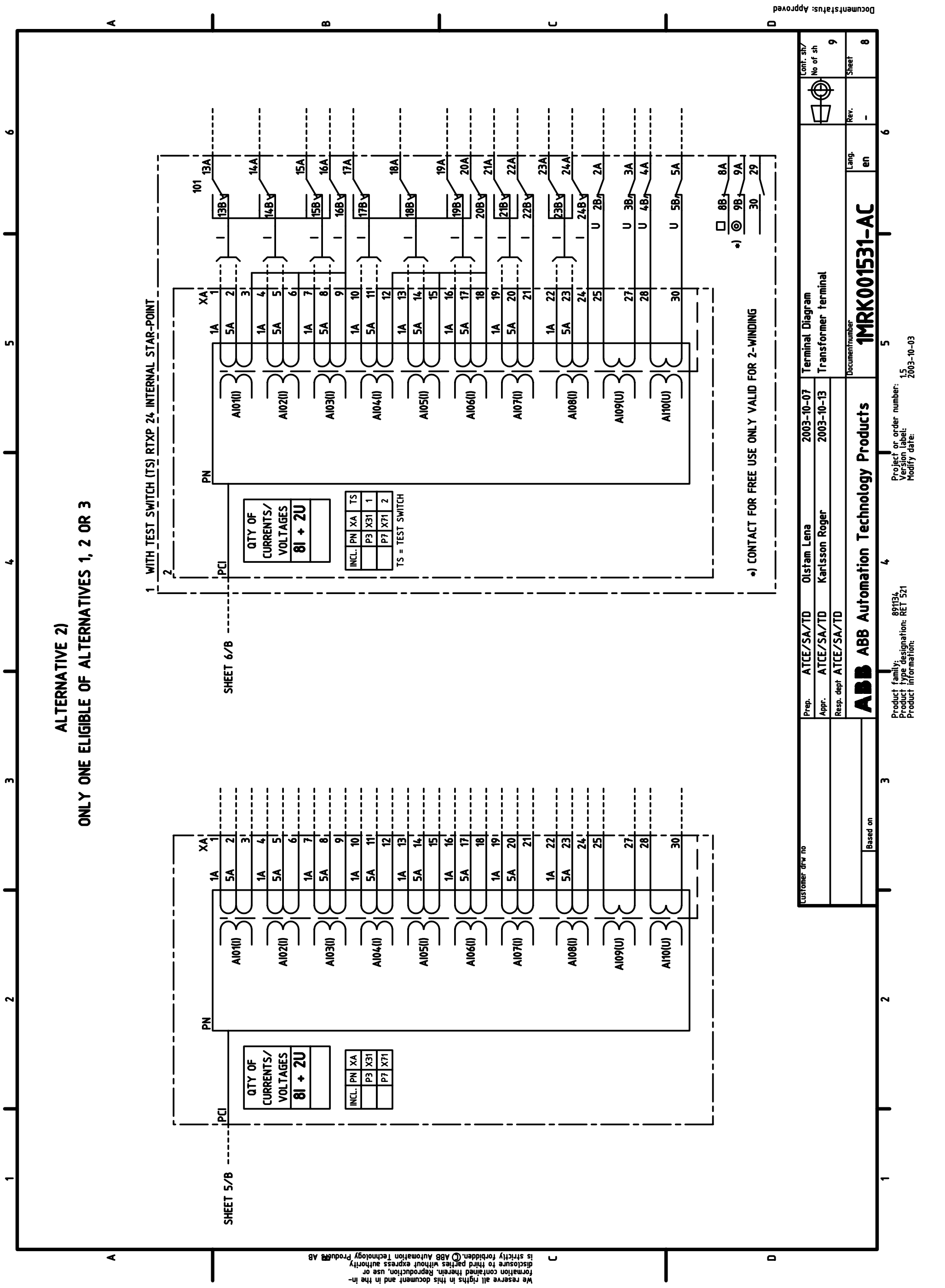
4.3 DC-switch


Documentstatus: Approved
ALT.1 SHEET 7/8
ALT.2 SHEET 8/8
ALT.3 SHEET 9/8
1) COMMUNICATION PORT TO SCS OR SMS WHEN INCLUDED.
2) COMMUNICATION PORT TO SCS WHEN LON IS INCLUDED.
3) OPTICAL PORT FROM LOCAL HMI. CONNECTION MADE WITH A SPECIAL INTERFACE CABLE.
4) NOT CONNECTED WHEN DC-SWITCH 1.501 IS INCLUDED.
5) DC-SWITCH OPTION
RET 521
PCI
INTERNAL FAIL
P14
SERIAL
LON
P8:1
P8
HMI
X81:TX
X82:RX
X83:TX
X84:RX
TX
RX
X14:1
X14:3
X14:2
X14:4
X14:5
2.X14:5
2.X14:4
EL
1.501:22
1.501:24
501
INTERNAL FAIL (NO)
INTERNAL FAIL (NC)
Terminal Diagram
Transformer terminal
1MRK001531-AC
ABB Automation Technology Products
Olstam Lena
Karlsson Roger
ATCE/SA/TD
2003-10-07
2003-10-13
Project or order number: 1.5
Modify date: 2003-10-03
Product type designation: RET 521

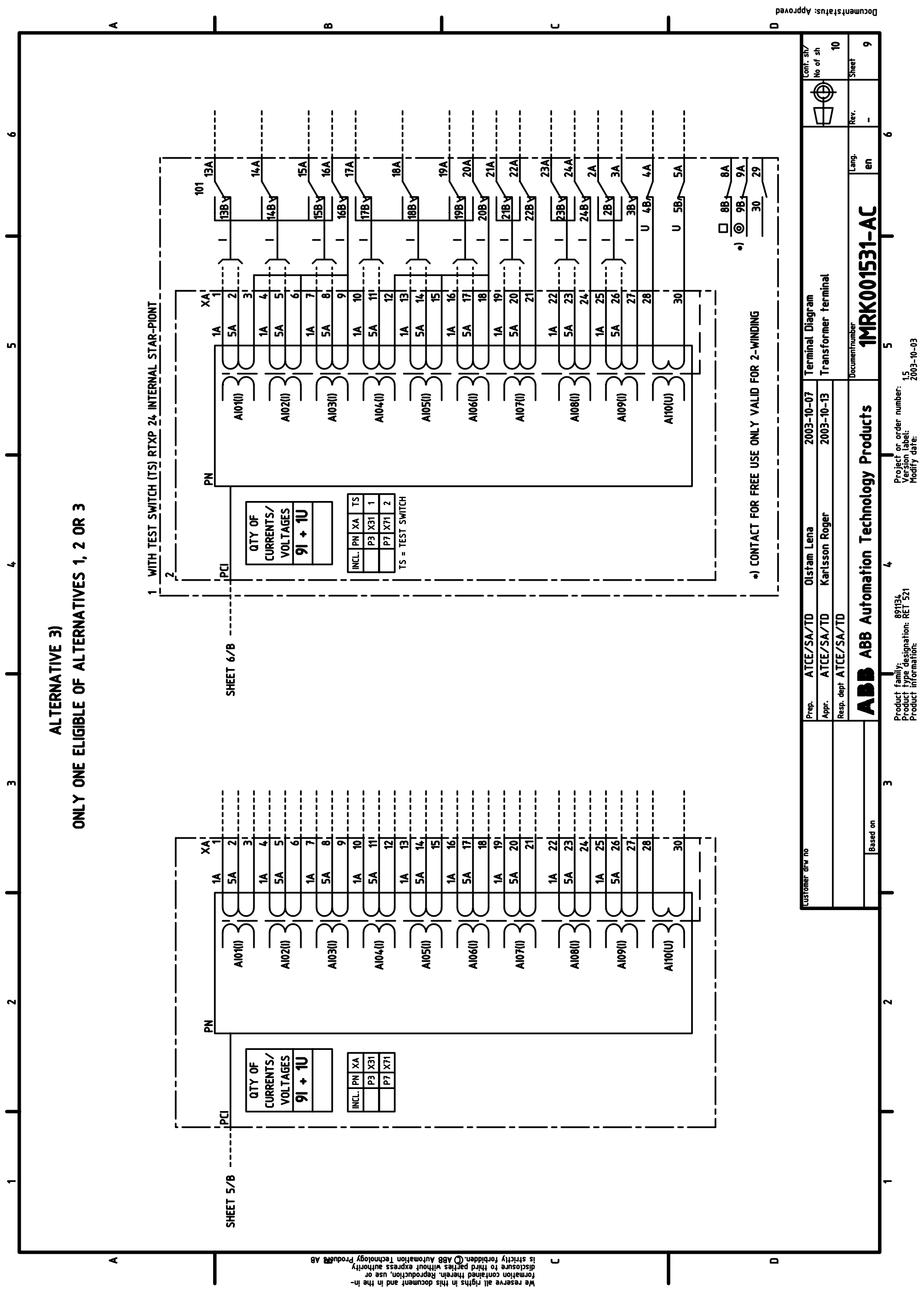
4.4 Analogue input module



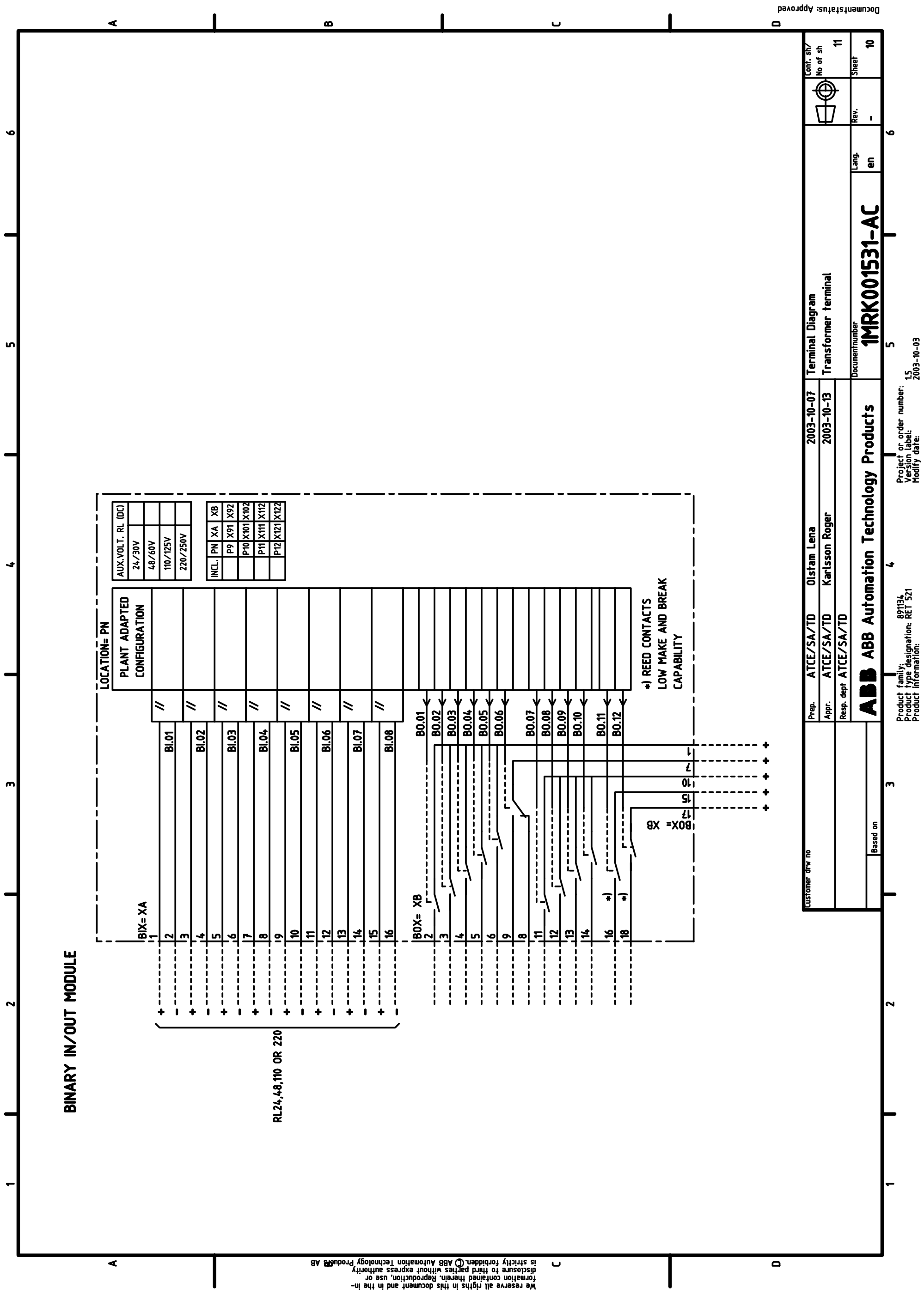
Analogue input module (cont'd)



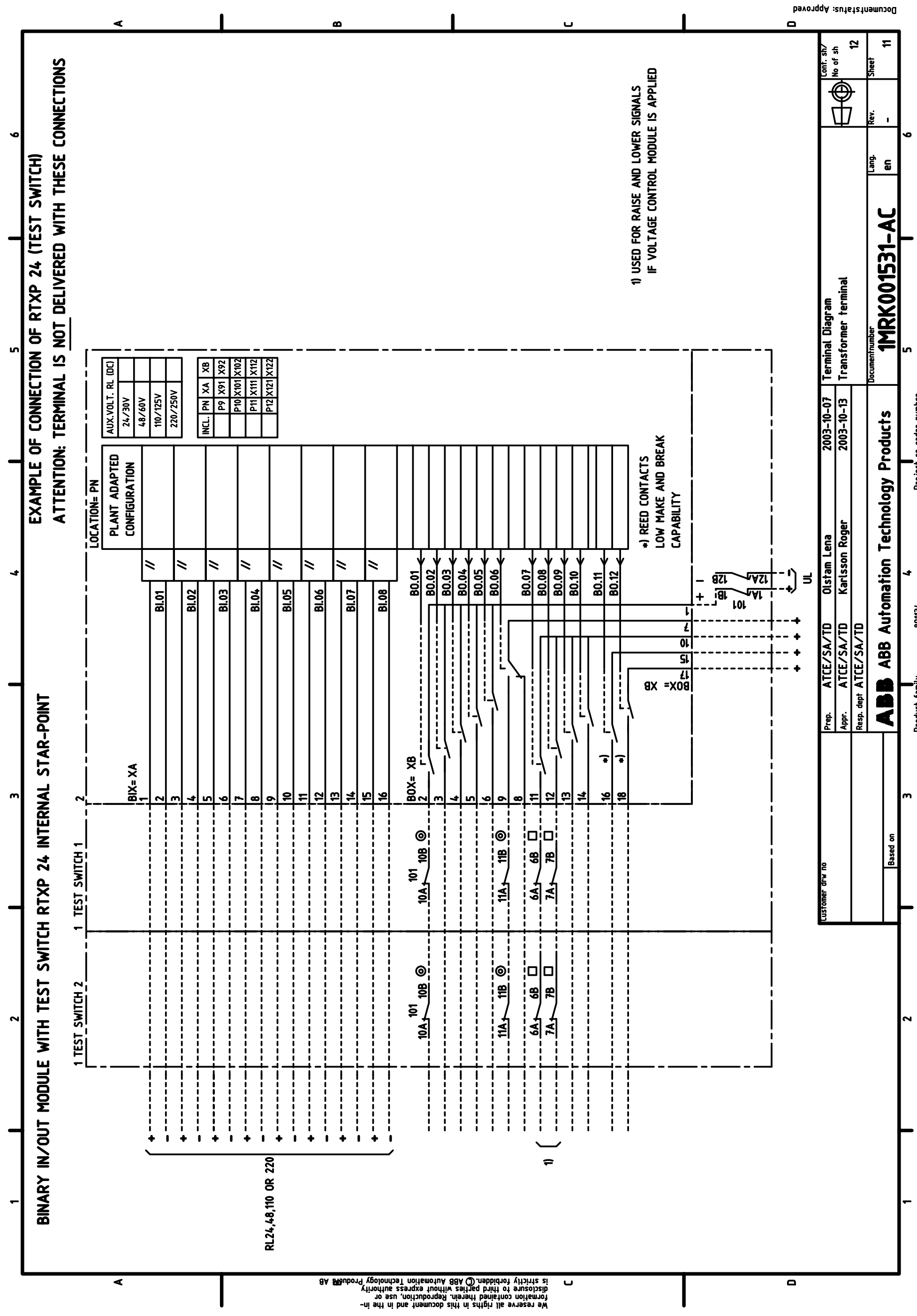
Analogue input module (cont'd)



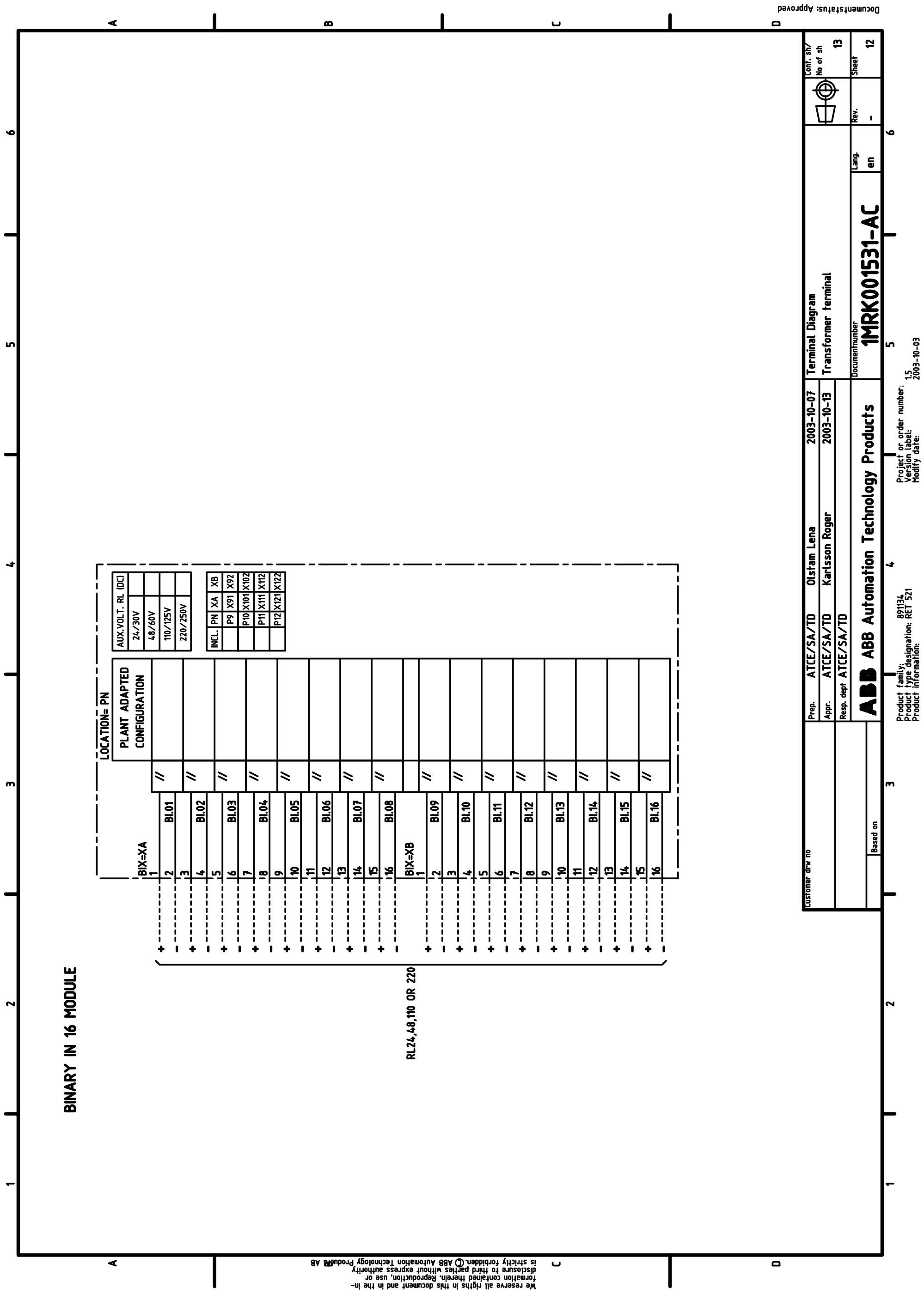
4.5 Binary in/out module



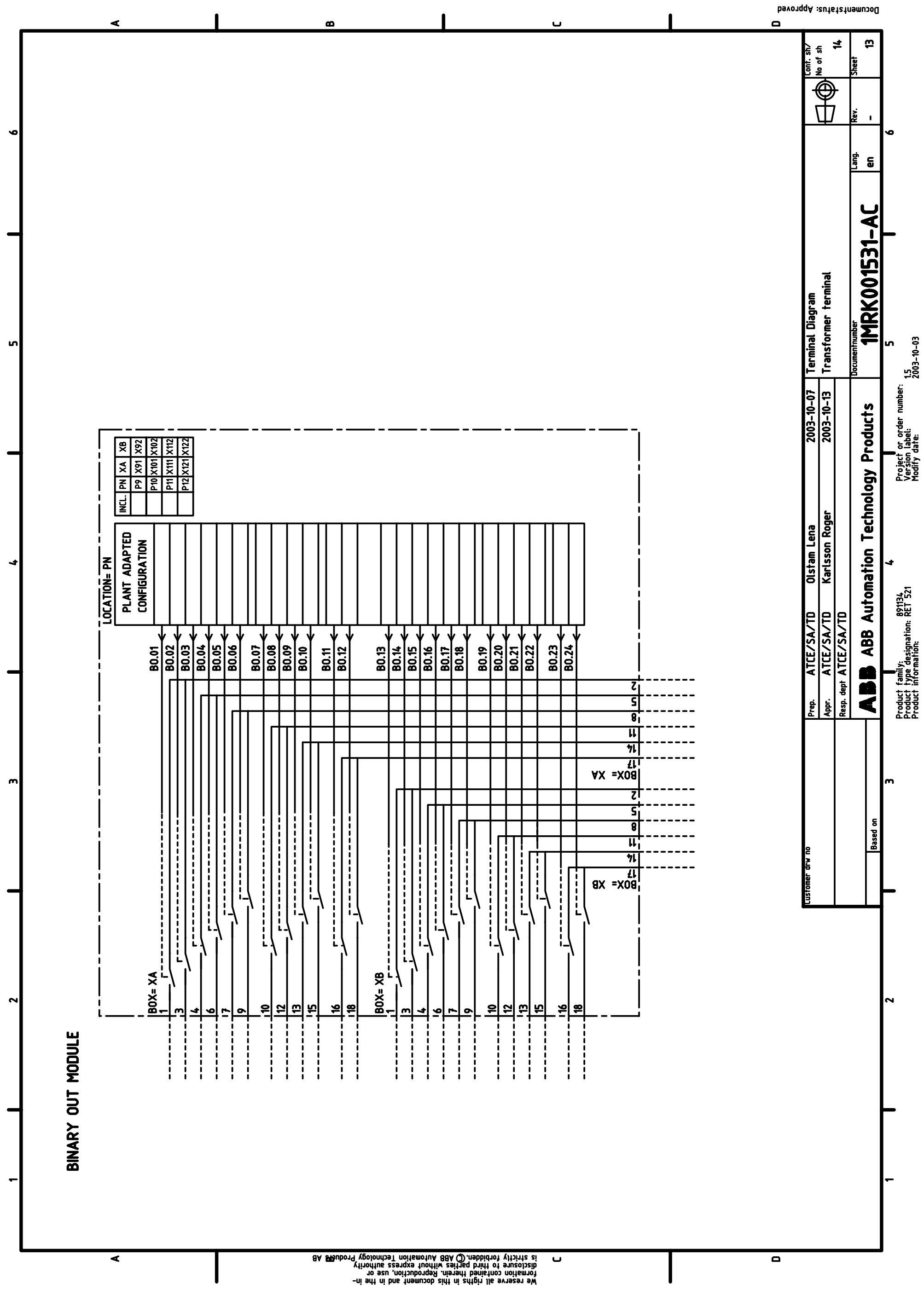
4.6 Binary in/out module with test switch RTXP 24 internal star-point



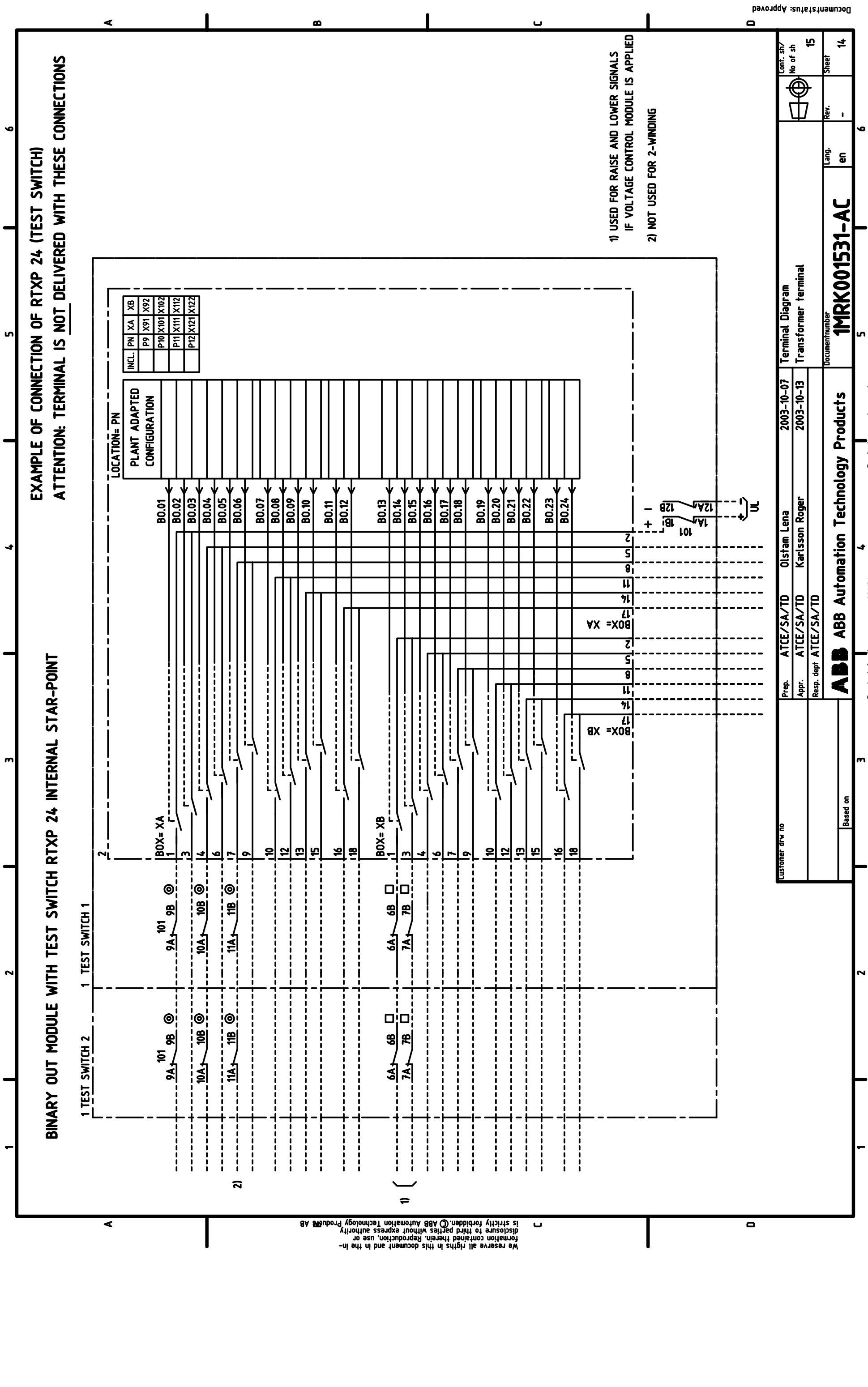
4.7 Binary in 16 module



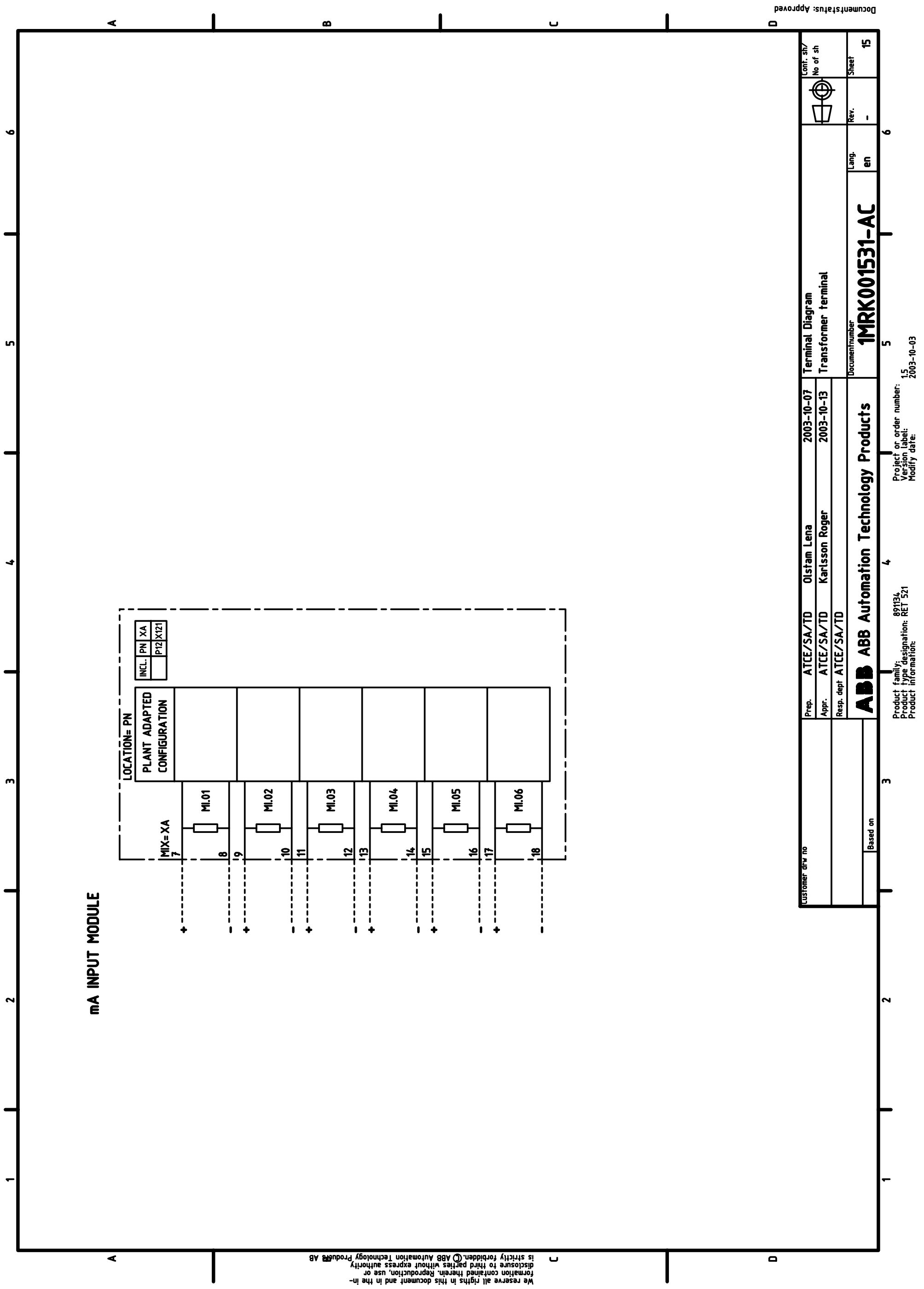
4.8 Binary out module



4.9 Binary out module with test switch RTXP 24 internal star-point



4.10 mA input module



HW-modules

5 Numerical module (NUM)

5.1 Hardware design

The NUM, NUmerical Module is a high performance, standard off-the-shelf compact-PCI CPU module. It uses the 6U-format on the board and takes one slot in height.

For communication with high speed modules ex. analog input modules and high speed serial interfaces the NUM is equipped with a Compact PCI bus. The NUM is the compact PCI system card i.e. it controls busmastering, clockdistribution and receives interrupts.

NUM is equipped with a PMC slot (32-bit IEEE P1386.1 compliant) in which as an option a daughtercard may be mounted e.g. an SLM for SPA and LON.

To reduce busloading of the compactPCI bus in the backplane the NUM has one internal PCI bus for internal recourses and the PMC slot and external PCI accesses through the backplane are buffered in a PCI/PCI bridge. If this division of the bus was not done there could not be eight slots on the bus since the CompactPCI standard only allows eight loads.

The application code and configuration data is stored in flash memory using a flash file system. During power up the application code is moved to and then executed from the DRAM. The code is stored in the flash memory because its nonvolatile and executed in DRAM because of the DRAMs higher performance.

The NUM is equipped with a real time clock. It uses a battery for power backup of the real time clock and this has to be changed on regular bases e.g. 5 years. This is only necessary when no time synchronization is used.

All the communication not possible with a standard CPU-module is added on the CEM.

No fans are used on this standard module since the power dissipation is low.

5.2 Technical specifications

The NUM conforms to the CompactPCI Specification revision 2.0.

Take care when using PMC modules as to how much current they require, especially from the +5V supply.

5.3 Block diagram

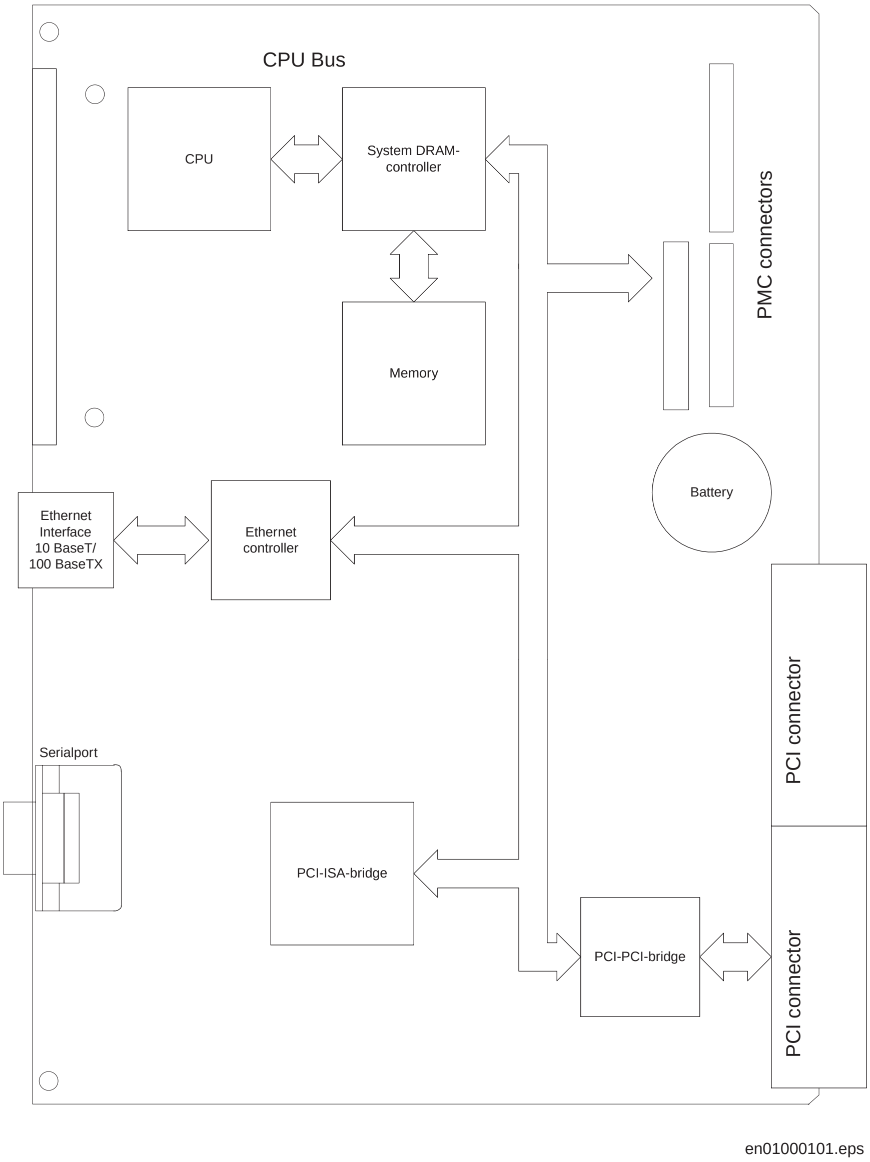


Fig. 3 NUmerical Module blockdiagram (actual placement of components differ)

6 Compact backplane module (CBM)

6.1 Hardware design

CBM is a backplane that has 8 CompactPCI connectors and 4 connectors for RCAN based ABB boards. One of the CompactPCI connectors have a special use since it hosts the CEM and is therefore mounted on the opposite side of the backplane. For the compact PCI slots a 220pin 2mm Hard Metric connector is used. The RCAN based ABB boards uses a 3 row, 96 pin standard Euro-connector. There is a need for some signals to be present in both connector types. For this purpose some of the User defined part of the CompactPCI connector is used. There are no user pins use on the system-slot (for the CPU-module).

The CompactPCI specification gives the possibility for a 3.3V OR 5V signaling in the backplane. The CBM backplane and connected modules must be 5V PCI-compatible.

Some pins on the CompactPCI connector is connected to the RCAN bus, to be able to communicate with RCAN based modules.

For identification in production and field upgrades the CBM is equipped with two IDchips with the contents of a factory programmed unique serialnumber and during production it is programmed with article number, hardware version and final test date. One ID contains backplane data and the other contains product data.

For the power supply there is a 3 row, 96 pin, Euro-connector.

For powerdegradation early warning there is a signal, ACFail.

If a modules selftest discovers an error it informs other modules through the Internal Fail signal.

6.2 Technical specifications

Table 8: Mounted connectors

Function	Connector identifier
Compact PCI	X1-8 (where X2 is mounted on the opposite side for CEM)
RCAN based	X9-12
Power supply	X14
MMI connector	X30

Table 9: The buses in the backplane are connected to the following connectors.

Bus	Connectors
Compact PCI	X1-8 (X8 according to v2.1 where no user pins are used, rest is according to v1.0 of the CompactCPI-standard)
RCAN	X1-7,9-12,14
MMI display and keyboard interface	X1-7,9-12
MMI optical communi-cation interface	X1-7,9-12

Table 10: Special signals

Signal	Description	Connector
PRST	System reset	X1-7,9-12,14
AC_FAIL_N	Power supply degradation early warning	X1-7,9-12,14
INTERNAL_FAIL_N	Module failure broadcast signal	X1-7,9-12,14
PPS, MPPS, CMPPS	Timesyncronisation	X1-7,9-12,14
SYS_ID	Electronic ID	X1-7,9-12,14

Impedance matching: Every signal is impedancematched to 65 Ohm +/-10%, calculated for a bare PCB.

6.3 Block diagram

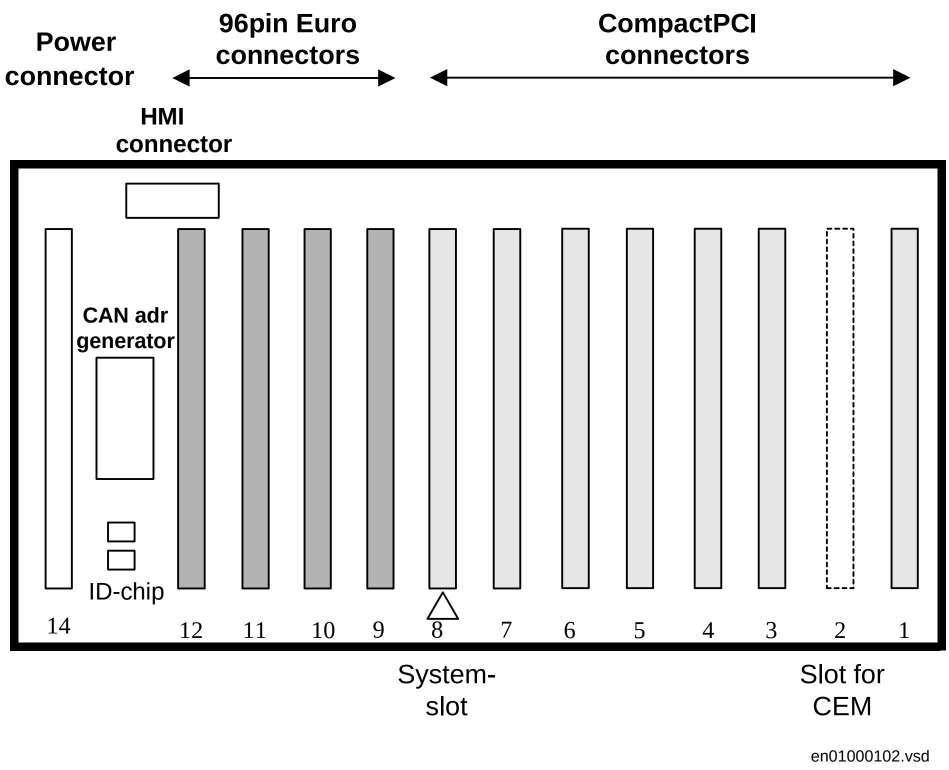


Fig. 4 Connectors on the 3/4 backplane as seen from the connector side

7 Combination Extension backplane Module (CEM)

7.1 Hardware design

CEM is an addition to the CBM and is mounted on the CompactPCI-connector X2 placed on the opposite side of the CBM. For the compact PCI slot a 220pin 2mm Hard Metric connector is used. All communication between the RCAN based ABB boards are handled inside the CEM.

There are also two asynchronous serial ports. One for the HMI-display and keyboard and one for the HMI optical interface.

For identification in production and field upgrades the CEM is equipped with two IDchips with the contents of a factory programmed unique serialnumber and during production it is programmed with article number, hardware version and final test date. One ID contains CEM data and the other contains the data about the standard CPU-module, NUM. It also handles the common ID-signal SYS_ID in the same way.

The CEM also handles the powerdegradation early warning signal, ACFail, and present this as an interrupt to the CPU-module.

If a modules selftest discovers an error it informs other modules through the Internal Fail signal. Since there is no direct connection to the CPU-module the CEM also handles this signal.

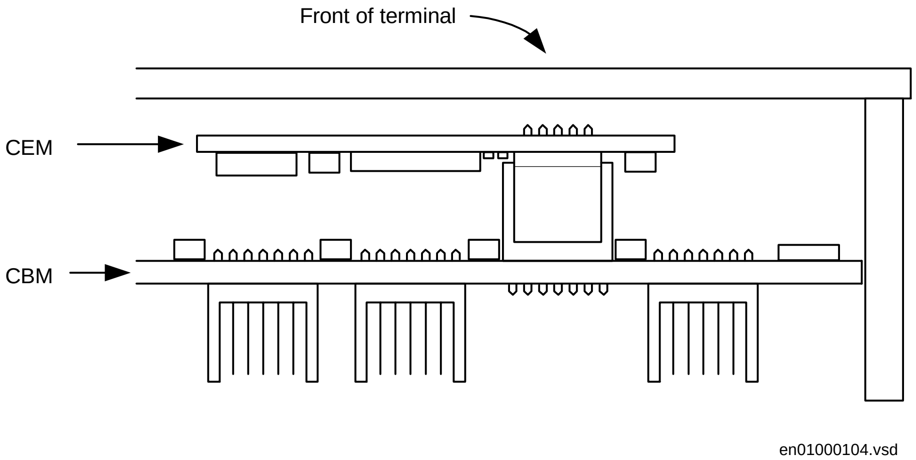


Fig. 5 CBM and CEM seen from the top of the terminal

7.2 Technical specifications

CEM uses the CompactPCI specification revision 1.0 where user pins are available.

Table 11: Resources

Function	Description
Serial I/O	HMI display and keyboard interface
Serial I/O	HMI optical communication interface
RCAN interface	Communication with all RCAN based modules on the backplane, CBM.
ID chips	Handling of the three ID-signals.

Table 12: Special signals

Signal	Description
PRST	System reset
AC_FAIL_N	Power supply degradation early warning

Table 12: Special signals

Signal	Description
INTERNAL_FAIL_N	Module failure broadcast signal
SYS_ID	Electronic ID
RCAN_ID	Rack information ID. Slot numbers

7.3 Block diagram

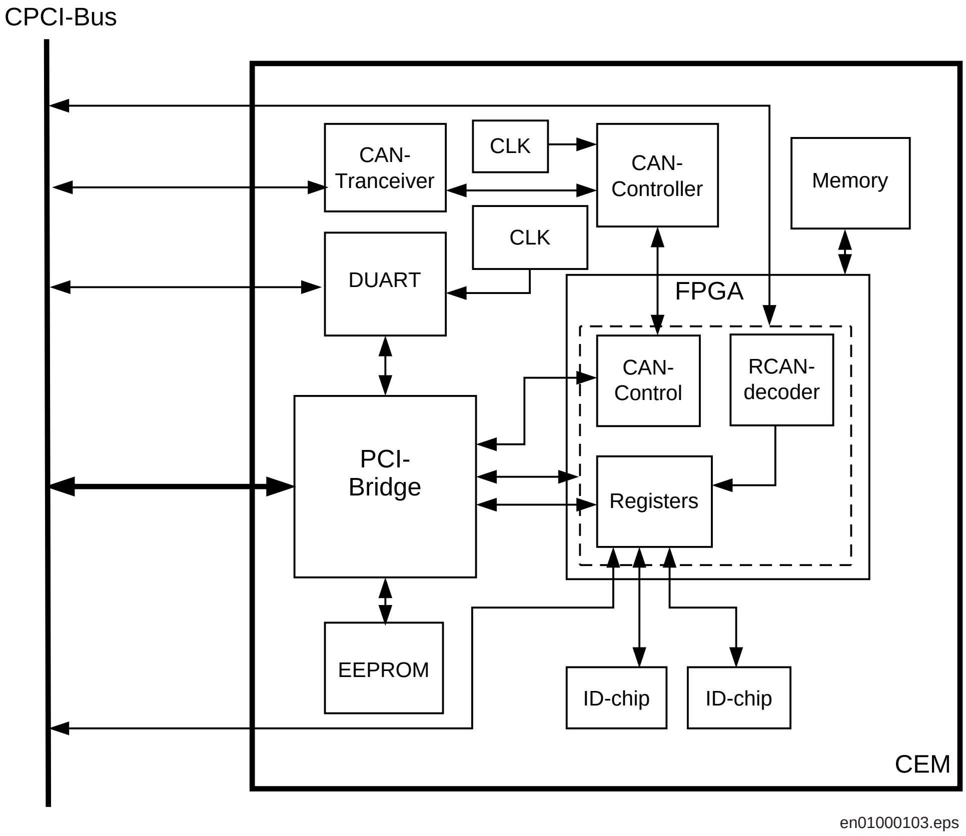


Fig. 6 CEM block diagram

8 Power Supply Module (PSM)

8.1 Hardware design

There are two different types of power supply modules. The power supply module contains a built-in, self-regulated DC/DC converter that provides full isolation between the terminal and the external battery system.

The PSM, converts an input voltage range from 24 to 60 V or 90 to 250 V, including a ±20% tolerance on the EL voltage.

The output voltages are +3.3, +5, +12 and -12 V and the module can provide 50W.

8.2 Block diagram

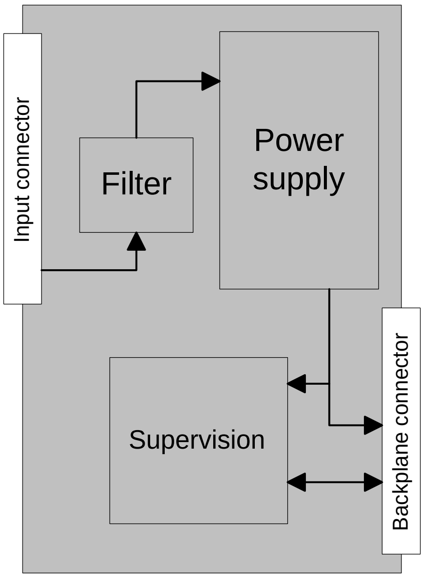


Fig. 7 Block diagram for the PSM.

9 Analogue input module (AIM)

9.1 Hardware design

The analogue input module (AIM) consists of two connectors for the external connections and two printed board assemblies; transformer board and A/D board.

Current and voltage input transformers are mounted on the transformer board. The transformers form an insulating barrier between the external wiring and the A/D-conversion board, and adapt the values of the measuring quantities to the input circuits of the A/D-conversion board. Maximum ten transformers can be mounted on the transformer board. The design is made for mounting of a current transformer alternatively a voltage transformer in all of the transformer places.

The other printed board assembly is the A/D-conversion board. Over a contact socket strip on the transformer board and a contact pin strip on the A/D board the signals from the transformers are transmitted to input channels of the A/D board. This board is mainly filtering and converting analogue to digital signals. The transmission of data between the A/D board of the analogue input module and the numerical module is done on a backplane board with a CompactPCI bus. The A/D board has ten measuring channels. The channels are equipped with components for current measuring alternatively voltage measuring.

The printed circuit board assemblies and the external connectors are attached with screws to a common mounting plate. The primary windings of the transformers are connected to the external connectors with cables.

Variants of the analogue input module are provided with components for time-synchronization. The time-synchronization components are located on the A/D board. An external synchronization pulse from a synchronization device will be used to get the same time everywhere in the system when the modules are distributed.

9.2 Technical specifications

9.2.1 Transformer board

Toroidal type of transformers are used as current input transformers and EI 38 type of transformers are used as voltage input transformers. The current transformers have windings for both 1A and 5A rated current. The voltage transformers are covering a rated range from 57,7V to 120V. The process interface of the external connector has screw terminals for maximum one conductor with the area 4mm^2 alternatively two conductors with the area 2,5 mm^2.

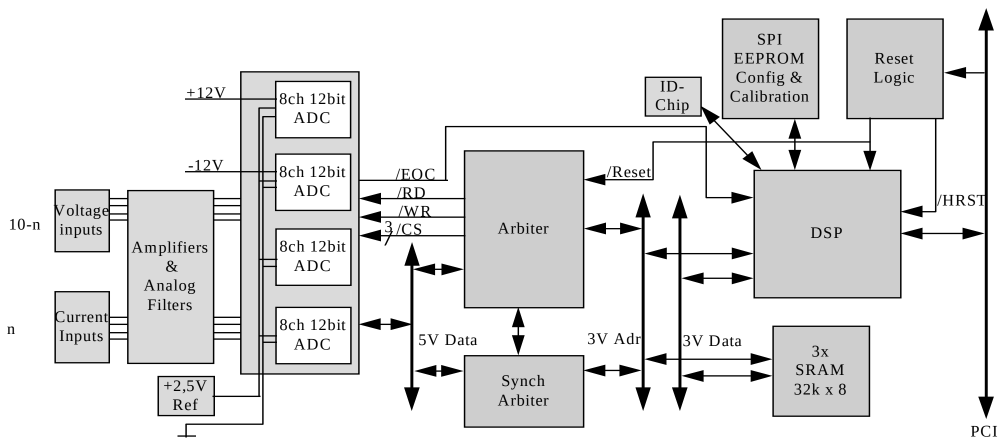
9.2.2 A/D-conversion board

The signals from the transformer board are amplified and filtered with a bandwidth of 10kHz on two ranges for each channel and converted with a resolution of 12 bits. The results, from the conversion on the two ranges, are combined into a single 24bit word and filtered in two cascaded decimation filters programmed into a digital signal processor (DSP).

The numerical filters are of finite impulse response type, giving a linear phase response and appropriate anti aliasing with a cut-off at 2300/2760Hz and 500/600Hz respectively, at 50/60 Hz rated frequency.

High accuracy is obtained by a calibration process and internal supervision of all vital functions is implemented.

9.3 Block diagram for the A/D-conversion board



10 mA input module (MIM)

10.1 Hardware design

The Milliampere Input Module has six independent analogue channels with separated protection, filtering, reference, A/D-conversion and optical isolation for each input making them galvanic isolated from each other and from the rest of the module.

The differential analogue inputs measure DC and low frequency currents in range of up to +/- 20mA. The A/D converter has a digital filter with selectable filter frequency. All inputs are calibrated separately and stored in a non-volatile memory and the module will self-calibrate if the temperature should start to drift. This module communicates, like the other I/O- modules, with the Main Processing Module via the CAN-bus.

10.2 Technical specifications

Table 13: Energizing quantities, rated values and limits

Quantity:	Rated value:	Nominal range:
mA input module		
input range	± 5, ± 10, ± 20 mA 0-5, 0-10, 0-20, 4-20 mA	± 10 %
input resistance	R_{in} = 194 Ohm	
power consumption		
each mA-board	≤ 4 W	
each mA input	≤ 0,1 W	

10.3 Block diagram

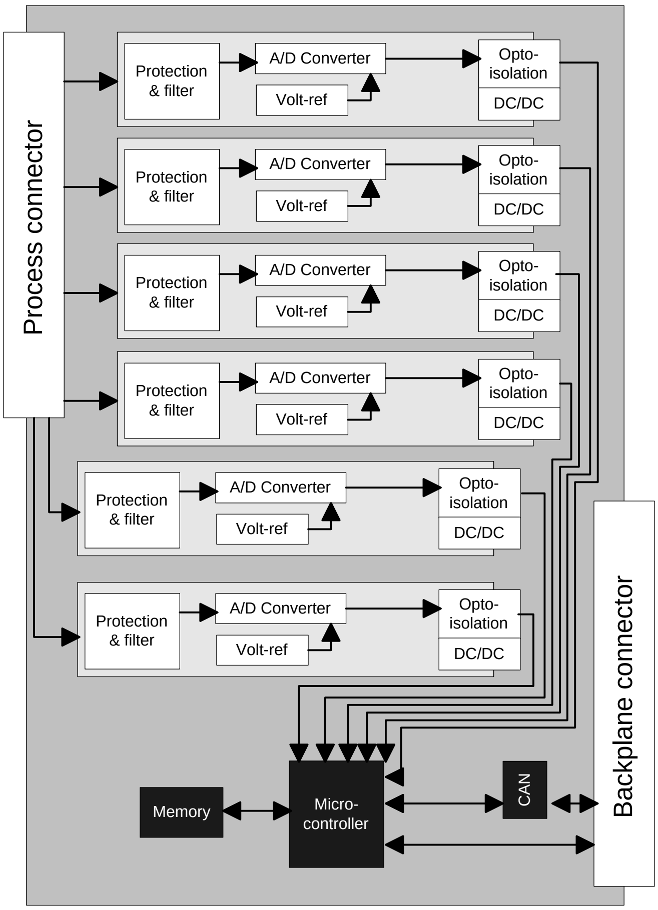


Fig. 8 Block diagram of the Milliampere Input Module

11 Binary input module (BIM)

11.1 Hardware design

In RET521 the number of inputs or outputs can be selected in a variety of combinations. There are no basic I/O configuration of the terminal. Many signals are available for signalling purposes in the terminal, and all are freely programmable. The voltage level of the input modules is selectable at order RL48, 110, or 220 (48/60 V ±20%, 110/125 V ±20% or 220/250 V ±20%). The Binary input module are also available in an RL 24 version (24/30 V ±20%).

The Binary input module contains 16 optical isolated binary inputs. The binary inputs are freely programmable and can be used for the input logical signals to any of the functions. They can also be included in the disturbance recording and event-recording functions. This enables the extensive monitoring and evaluation of operation for the terminal and for all associated electrical circuits. You can select the voltage level of the Binary input modules (RL24, 48, 110, or 220) at order.

Fig. 9 shows the operating characteristics of the binary inputs of the three voltage levels.

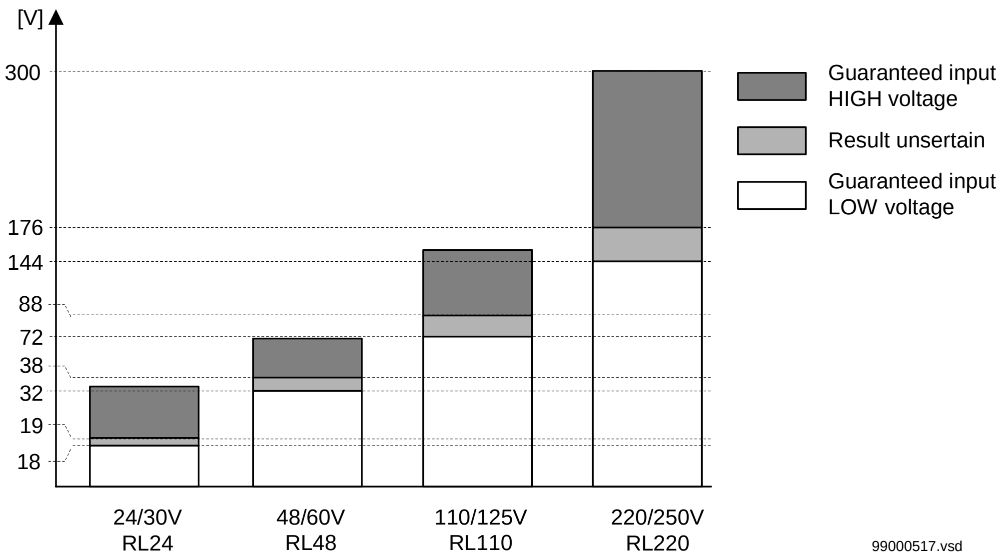


Fig. 9 Voltage dependence for the binary inputs

This module communicates with the NUmerical Module via the CAN-bus on the backplane.

The design of all binary inputs enables the burn off of the oxide of the relay contact connected to the input, despite the low, steady-state power consumption, which is shown in Fig. 10.

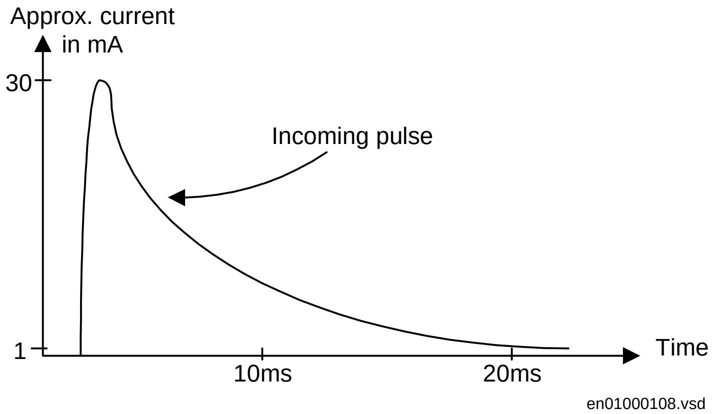


Fig. 10 Current through the relay contact

11.2 Technical specifications

Table 14: Energizing quantities, rated values and limits

Quantity	Rated value	Nominal range
Binary input module		
dc voltage RL	RL24 = (24/30)V	± 20 %
	RL48 = (48/60)V	± 20 %
	RL110 = (110/125)V	± 20 %
	RL220 = (220/250)V	± 20 %
power consumption		
each input-board	≤ 0,5 W	
RL24 = (24/30)V	max. 0,05 W/input	
RL48 = (48/60)V	max. 0,1 W/input	
RL110 = (110/125)V	max. 0,2 W/input	
RL220 = (220/250)V	max. 0,4 W/input	

11.3 Block diagram

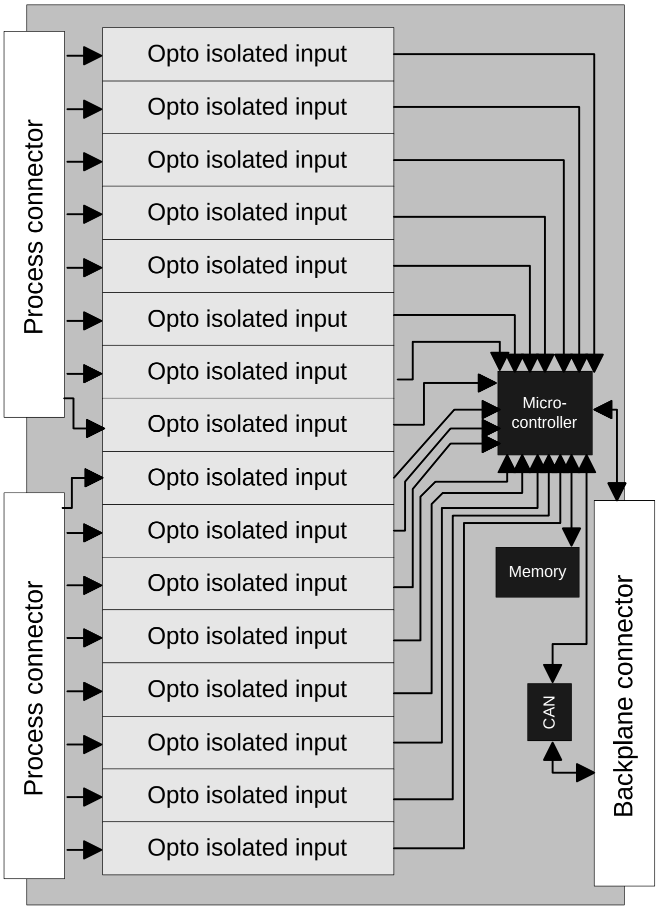


Fig. 11 Block diagram of the Binary input

12 Binary output module (BOM)

12.1 Hardware design

The Binary output module has either 24 single-output relays or 12 command-output relays. They are grouped together as can be seen in the block diagram below. All the output relays have contacts with a high switching capacity (Trip and signal relays).

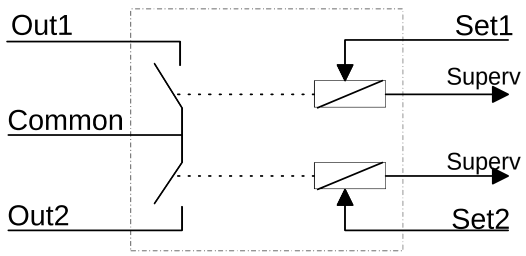


Fig. 12 One of twelve binary output groups

12.2 Technical data

Quantity:	Rated value:	Nominal range:
Binary output module power consumption each output-board each output relay	 ≤ 1,0 W ≤ 0,25 W	

12.3 Block diagram

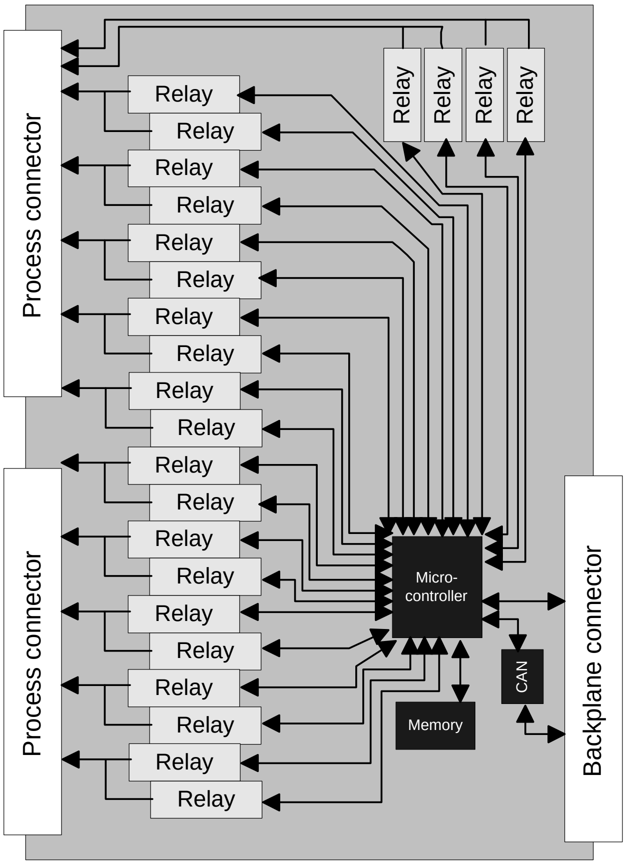


Fig. 13 Block diagram of the Binary Output Module

13 Binary In/Out Module (IOM)

13.1 Hardware design

The Binary in/out module contains eight optical isolated binary inputs and twelve binary output contacts. Ten of the output relays have contacts with a high-switching capacity (Trip and signal relays). The remaining two relays are of reed type and for signalling purpose only. The relays are grouped together as can be seen in the terminal diagram.

The voltage level of the output moduleis selectable at order RL48, 110 or 220 (48/60 V ±20%, 110/125 V ±20% or 220/250 V ±20%).

13.2 Technical data

Quantity:	Rated value:	Nominal range:
Binary output (8)/output (12) module DC voltage RL	 RL = 24/30 V RL = 48/60 V URL = 110/125 V RL = 220/250 V	 ±20% ±20% ±20% ±20%
power consumption each I/O board each output relay RL = 24/30 V RL = 48/60 V RL = 110/ 125 V RL = 220/250 V	 ≤ 1W ≤ 0,15 W max. 0,05 W/input max. 0,1 W/input max. 0,2 W/input max. 0,4 W/input	

13.3 Block diagram

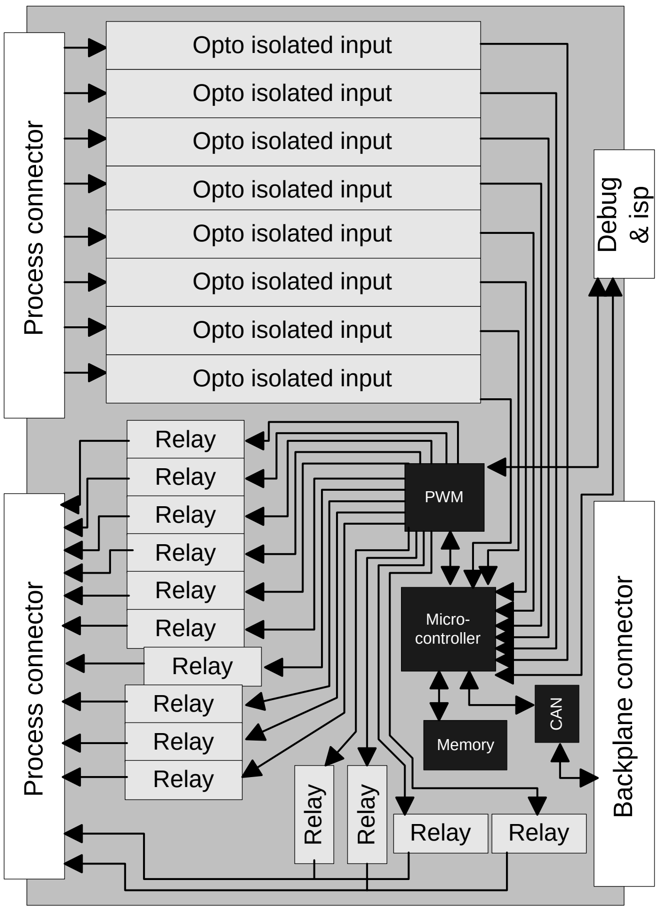


Fig. 14 Block diagram for the binary input/output module

Referenced publications

No applicable publications available.

Numerics

2-nd harmonic restrain *126*
3-winding power transformers *114*

A

A/D-conversion board *331*, *332*
AIM, Analog Input Module *305*
AIMx function block *53*
Always *126*
Ampere-turn balance *112*
Analogue input module (AIM) *53*, *55*, *331*
analogue input module (AIM) *53*
Analogue signal trig *284*
AND *82*
Annn-INPUTm *82*
Annn-NOUT *82*
Annn-OUT *82*
ASCII based protocol *300*

B

battery-backed RTC *35*
baud rate *300*
bias characteristics *128*
BIM, Binary input module *306*
binary in/out module *338*
binary input *33*
Binary input module (BIM) *53*, *57*, *334*
Binary output module *337*
Binary output module (BOM) *54*, *58*
Binary signal trig *284*
BOM, Binary output module *306*
BOUND *274*
breaker-and-a-half configuration *117*
British Standard BS 171 *109*
built-in HMI *36*
Built-in real time clock *29*
built-in real time clock (RTC) *33*
built-in supervisory functions *29*
busmastering *323*

C

calculation of an appropriate bias *119*
Calculation of Differential Current *179*
Calculation of fundamental harmonic differential currents *112*
Calculation of IEC inverse delay *160*, *194*
Calculation of IEC inverse delays *146*
calendar *33*
calibration process *332*
CAN based module *307*
CAN bus *305*
CAN bus slot *53*
CANPx-MIM1 *30*
CANPx-YYYn *30*
CAP 531 Configuration tool *32*
CAP 531 configuration tool *50*, *273*
Causes for error signals *38*
CBM, Combined Backplane Module *305*
CDxx-OUT1 *92*
CDxx-OUT16 *92*
CDxx-signal name *93*
Check of synchronisation signals *38*
clearing of disturbance reports *31*
clock and calendar *33*
clockdistribution *323*
CMxx-signal name *94*
COARSE *36*
Coarse message *33*
CoarseTimeSrc *34*
communic. betw. ctrl. terminals *274*
Communication between terminals *93*, *274*
Compact PCI bus *323*
CompactPCI modules *305*
Configurable logic (CL) *80*

D

DC/DC converter *306*
Dd0 (and Yy0) *116*
definite delay *140*
Detection of inrush *124*
Detection of overexcitation magnetizing currents *126*
Determination of bias current *127*, *128*
Determination of differential (operate) currents *111*
Differential currents *118*
Differential protection (DIFP) *107*
differential protection (DIFP) *178*
DIFP logic diagram *135*
directional check *181*
Directional control *147*, *195*
Directional criterion *181*
Disturbance index *280*
Disturbance Overview *280*
Disturbance recording *280*
Disturbance Report *279*
Disturbance reports *17*
Double indication *274*
double indication *274*

E

Earth fault relays *186*
Earth fault time current protection (TEF) *154*, *185*
EI 38 type *331*
Elimination of zero-sequence currents *119*
EMC safety *305*
Error signals *37*
Eurocard industry mechanical standard *305*
Event function blocks *273*
Event recorder *280*
Events in a disturbance report *17*
Events transmitted to the SCS *17*
EVxx-signal name *275*
external earth fault *176*
External Earth Faults *180*
External time synchronization *29*
extremely inverse *140*
Extremely Inverse characteristics *144*, *191*

F

fault time *281*
faults in the terminal *31*
FIFO principle *31*, *281*
filtering and calibration adjustments *305*
Fine message *33*
FineTimeSrc *34*
Forward *195*
fundamental frequency differential currents *117*

G

General disturbance information *280*
General functionality *50*
group Yd1 *116*

H

Hardware design *305*
harmonic analysis *124*
heavy external faults *119*, *131*
HMI *30*

I

I/O hardware position (IOHW) *54*
I/O modules *53*
I/O system configuration *53*
I/O-system configuration (IOHW) *53*
identifiers *18*
IEC 255-4 *188*
IEC 76 standard *109*
IEC 76-4 (1976) *109*
Indications *280*
input resistance *333*
Input/output module (IOM) *54*, *59*
inrush magnetizing currents *119*, *121*
Inrush phenomenon *121*
Instantaneous differential currents *118*
instantaneous differential currents *112*
Intern Warning *30*
internal clock *17*
internal event list *32*
Internal events *17*, *29*, *32*
internal supervision *332*
InternFail *30*
InternSignals (INT) *32*
INTERVAL *274*
INTERVAL time *93*
INT--FAIL *33*
INT--NUMFAIL *33*
INT--NUMWARN *33*
INT--SETCHGD *33*
INT--WARNING *33*
inverse delay *140*
Inverter (INV) *81*
IOM *338*
IOM, Input and output module *307*
IOxx function block *53*
IVnn-INPUT *81*
IVnn-OUT *81*

L

limit time *283*
loaded power transformer *111*
Logarithmic Curves *193*
Logic diagram
  directional TOC (lowset stage only) *151*
  nondirectional TOC *150*
logic Inverter (INV *81*
LON *298*
LON bus *93*, *274*
LON channel Module *306*
LON communication *299*
LON Network Tool *274*, *301*
LON Star Coupler *301*
long-time inverse *140*
Long-time Inverse characteristics *145*
Longtime Inverse characteristics *192*
LonTalk protocol *299*
LonTALKProtocol Specification *300*

M

mA input module (MIM) *54*, *60*, *329*, *332*
Main CPU *306*
Manual trig *284*
maximum sensitivity *132*
Memory capacity *285*
mezzanine card *306*
midposition suppression *274*
MIM, Milliampere input module *307*
MINSYNC *36*
minute pulses *34*
MODE input *92*
MOF *84*
MOL *84*
MOVE *84*
MOVE function blocks *80*
Multiple Command *92*

N

neutral voltage protection *206*
No events *273*
Non-directional earth fault protection *156*, *187*
non-volatile cyclic memory *281*
normal inverse *140*
Normal Inverse curves *142*, *189*
NUM module *305*
NUM, Numerical Module *306*
numerical filters *332*
Numerical module (NUM) *323*
numerical module status *31*
NUM-modFail *30*
NUM-modWarning *30*

O

OnChange *273*
On-Load Tap-Changer (OLTC) *116*
On-Load-Tap-Chager (OLTC) *178*
Onnn-INPUTm *81*
Onnn-NOUT *81*
Onnn-OUT *81*

OnReset *273*
OnSet *273*
optical fibres *300*
opto/electrical converter *300*
OR *81*
overexcitation magnetizing currents *119*
overvoltage protection *203*

P
passive backplane *305*
PCI bus *305*
PCI bus slot *53*
PCIPx-AIMn *30*
peak flux density *123*
phase-to-phase *206*
pier-to-pier protocol *300*
PMC slot *323*
post fault time *281*
post-fault tim *283*
Power transformer connection groups *110*
Power transformer turns-ratio *115*
pre-fault buffer *283*
pre-fault time *281*, *283*
primary winding *109*
protection algorithm *127*
PSM, power supply module *306*
Pulse *83*

R
RCA *182*, *187*
Real Time Clock *30*
recorded disturbance *282*
Recording times *282*
Relay Characteristic Angle *182*
Relay Characteristic Angles *187*
Relay Operate Angles *187*
remote communication *298*
Remote communication (RC) *298*
Remote HMI *305*
residual voltage protection *205*, *206*
Restricted earth fault protection (REF) *174*
Reverse *195*
ROA *182*, *187*

S
SA *298*
Sampling rate *285*
saturating condition *123*
SCADA *298*
search for an external fault *132*
secondary winding *109*
self supervision *305*
Self-supervision signals *30*
self-supervision summary *31*
serial buses *33*
serial ports *33*
SET-PULSE time *50*
Setting date and time *37*
setting restriction *41*
signal processor (DSP) *332*
Single Command *92*
Single/three-phase time undervoltage protection (TUV) *212*
slave number *300*
SM/RET 521 *31*
SMS *298*
SMS (Station Monitoring System) *37*
SPA *298*
SPA bu *305*
SPA bus V 2.4 protocol *299*
SPA communication *300*
SPA port *300*
SPA/VDEW-6 bus *306*
speed of the communication *301*
Stability of differential protection *131*
staring date and tim *33*
Start and stop of recording *283*
station master clock *34*
station monitoring system *300*
Station Monitoring System (SMS) *273*
Storage and data format *285*
Substation Control System (SCS) *32*
supervisory functions *29*
Swedish Standard SS 427 01 0 *109*
synchronisation message *33*
SYNSOURC *36*

T
T configuration *117*
technical data *333*, *335*
Terminal identification *17*, *20*
tertiary winding *109*
The 90 degrees connection *148*
Thermal overload protection (THOL) *218*
Three/phase time overcurrent protection (TOC) *139*
time characteristic
    Definite *188*
    Inverse *188*
Time characteristics *140*
time characteristics *188*
Time function block *39*
time pulse circuit *50*
Time source configuration alternatives *35*
time stamping *305*
Time Sync *31*
Time synchronisation *32*, *33*
Timer *82*
TIME-RTCERR *37*
TIME-SYNCERR *37*
TMnn-T *82*, *83*
Toroidal type *331*
total number of taps *116*
TPnn-INPUT *83*
TPnn-OUT *83*
transient condition *121*
trip logic block *50*
Trip values *280*
Tripping logic (TR) *50*
TRxx-(....,..) *50*

U
Unrestrained (instantaneous) differential protection *131*
unwanted operations *111*
Using front-connected PC *31*
Using SCS *32*
Using the built-in HMI *30*

V
VDEW-6 bus *305*
very inverse *140*
Very Inverse curves *143*, *190*, *207*

W
waveform analysis *125*
waveform check *125*

Z
zero sequence current *111*
zero sequence currents *119*, *187*

Customer feedback report

Product:

ABB Automation Technology Products AB would appreciate your comments on this product. Please grade the following questions by selecting one alternative per category. Your answer will enables us to improve our products.

How do you grade the quality of the product?

	Excellent				Poor
Total impression	☐	☐	☐	☐	☐
Useability	☐	☐	☐	☐	☐
Functionality	☐	☐	☐	☐	☐
Human-machine interface	☐	☐	☐	☐	☐

Comments: ______________________________

How do you grade the quality of the documentation?

	Excellent				Poor
Total impression	☐	☐	☐	☐	☐
Layout	☐	☐	☐	☐	☐
Illustrations	☐	☐	☐	☐	☐
Readability	☐	☐	☐	☐	☐
Easy to find	☐	☐	☐	☐	☐
Content structure	☐	☐	☐	☐	☐

Comments: ______________________________

Remove from binder

Customer feedback report

Suggestions for improvments:

Remove from binder

Please send this report to:

ABB Automation Technology Products AB
Substation Automation
ATCE/SA, Support Line
SE-721 59 Västerås
Sweden
Facsimile: + 46 (0) 21 14 69 18

Description Example Config no1 (1MRK 001 536-22)

Description	Work Sheet No
List of Content	Sheet No 01
Short Configuration Description	Sheet No 02
Configuration of Current & Voltage Signals	Sheet No 03
Differential Protection Function	Sheet No 04
HV Protection Functions	Sheet No 05
LV Protection Functions	Sheet No 06
Tripping Logic	Sheet No 07
Voltage Control Function	Sheet No 08
Configuration of Binary Input/Output Module	Sheet No 09
Configuration of Disturbance Report	Sheet No 10 & 11
Subsidary Configuration	Sheet No 12
Configuration of Event Reporting via LON bus	Sheet No 13 to 18

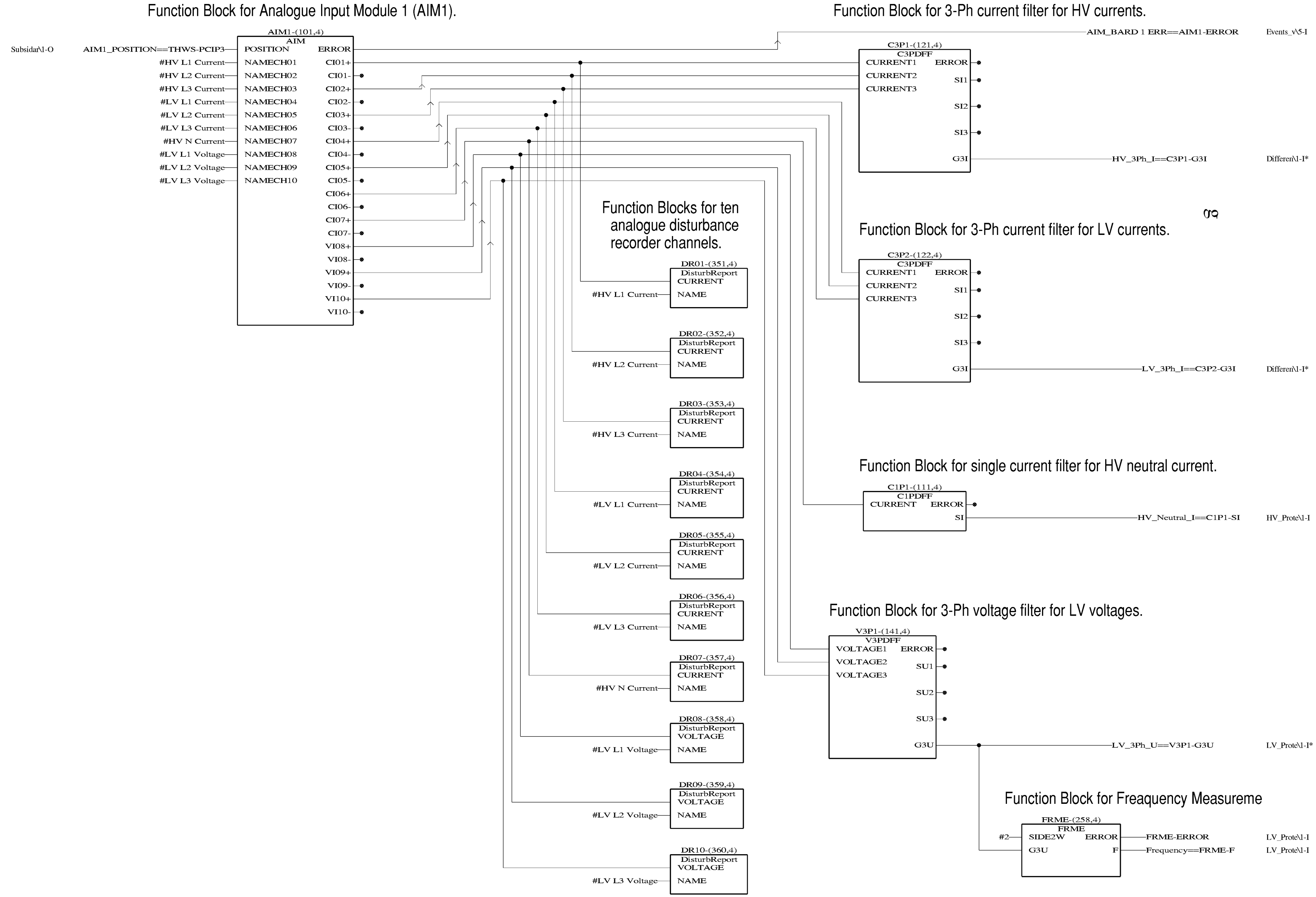
Prepared		02-04-15	RET 521 2p4
Approved	Birger Hillström	02-04-20	ABB Autom. Techn. Prod. AB
Rev Ind	Reg nr	Resp dep SA/ATA	Rev Ind
Based on	Pcl	Example 1	Overall_ Sheet 1/2

Short configuration description

The example configuration No 1 is made for protection and control of a two winding power transformer.
In the RET 521 terminal the following hardware modules are included: one AIM (7I+3U) & one IOM.
It is assumed that analogue inputs are connected to the following order: HV_IL1, HV_IL2, HV_IL3, LV_IL1, LV_IL2, LV_IL3, HV Neutral Current, LV_UL1, LV_UL2 & LV_UL3.
The following protection and control function are included in the configuration:
Transformer bias differential protection (87T & 87H); HV restricted earth fault protection (87N),
Directional 3-Ph OC protection (67); HV EF protection (50N, 51N); Thermal overload protection (49)
LV 3-Ph OC protection (50, 51); LV EF protection (50N, 51N); LV 3-Ph U< protection (27); LV 3-Ph U> protection (59);
Overexcitation protection (24) and LV side voltage control (90).
Individual tripping logic for CBs on both transformer sides are provided.

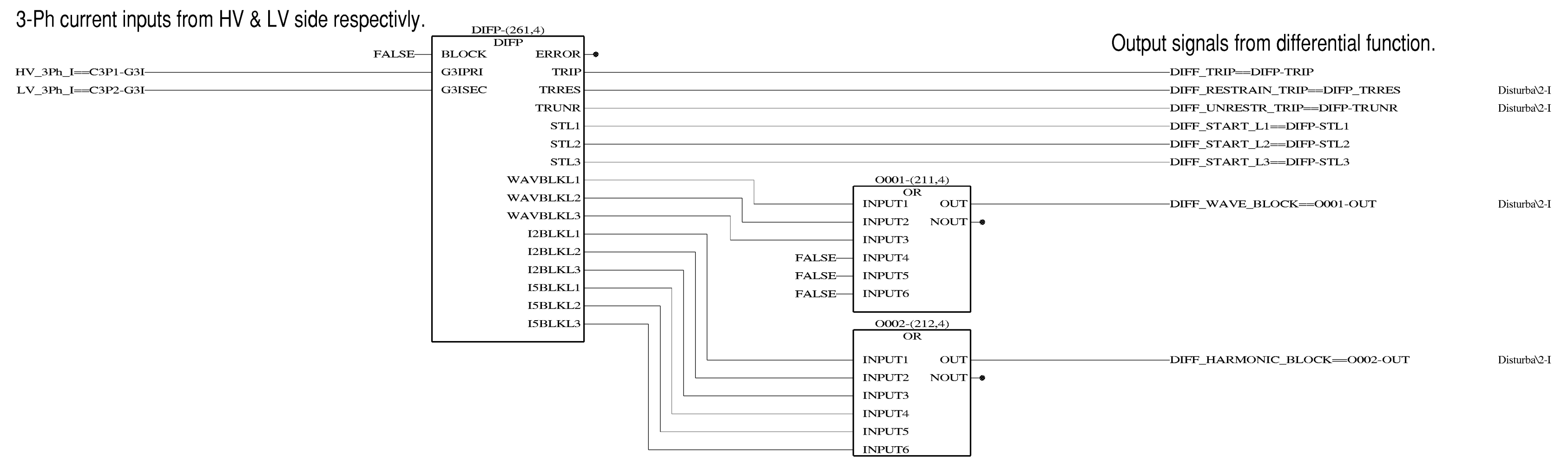
All 10 analogue input signals are connected to the disturbance recorder. In addition to that 48 binary signals are are connected to the disturbance recorder as well.

Finally binary events to the substation control system which will be automatically reported via LON bus are configured.

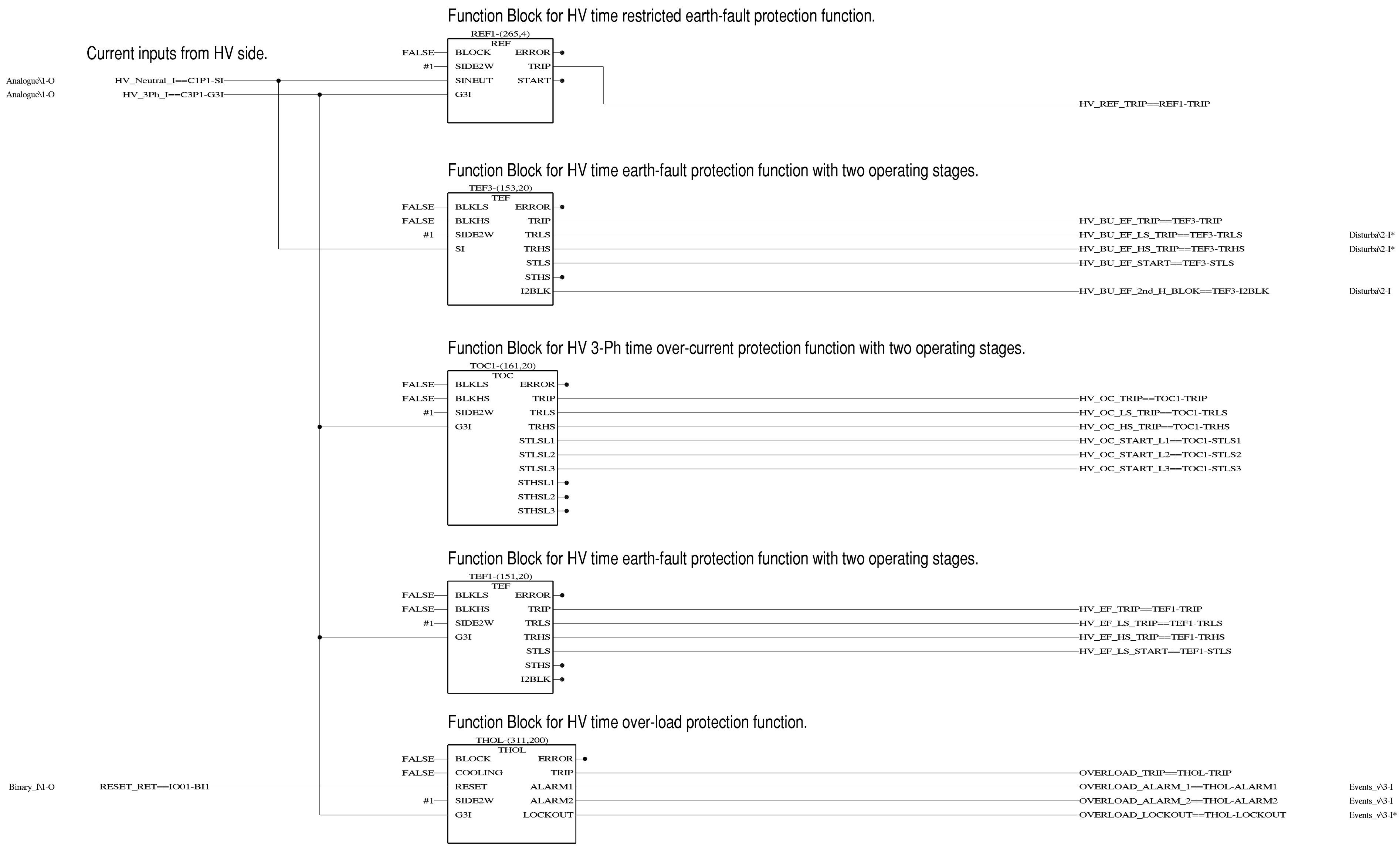


Prepared		02-04-15	RET 521 2p4	Analogue
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA Rev Ind
Rev Ind		Reg nr	ABB Autom. Techn. Prod. AB	Example 1 Sheet 1/1
Based on		Pcl		

Function Block for 2-winding differential protection function.

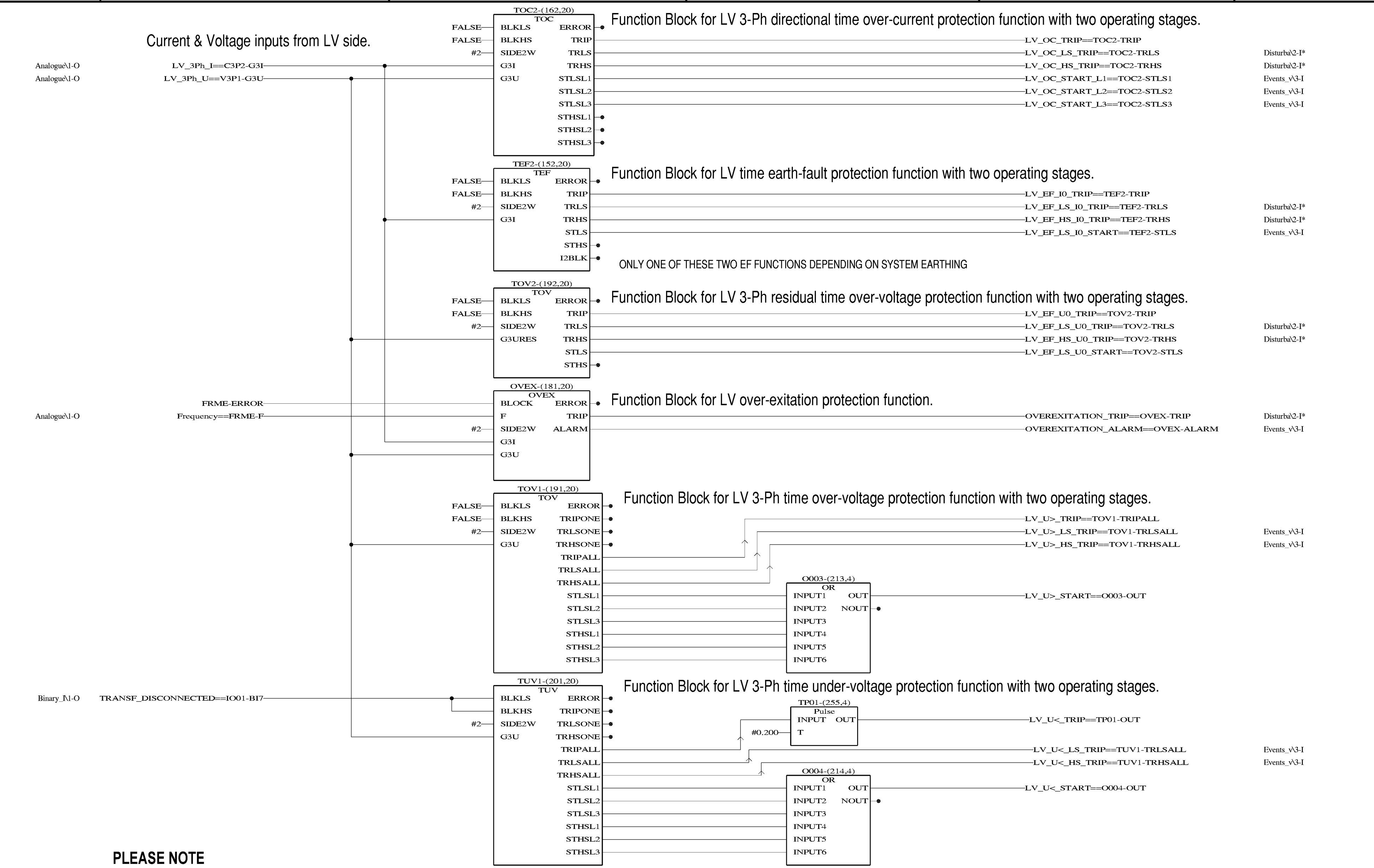


Rev Ind	Reg nr	Prepared	02-04-15	RET 521 2p4	Differen
Based on	Pcl	Approved Birger Hillström	02-04-20	ABB Autom. Techn. Prod. AB	Resp dep SA/ATA Rev Ind
				Example 1	Sheet 1/1



PLEASE NOTE that on all HV protection functions parameter SIDE2W must be set to value 1 in order to indicate to the respective function that it is connected to the HV (i.e. primary) side of the power transformer.

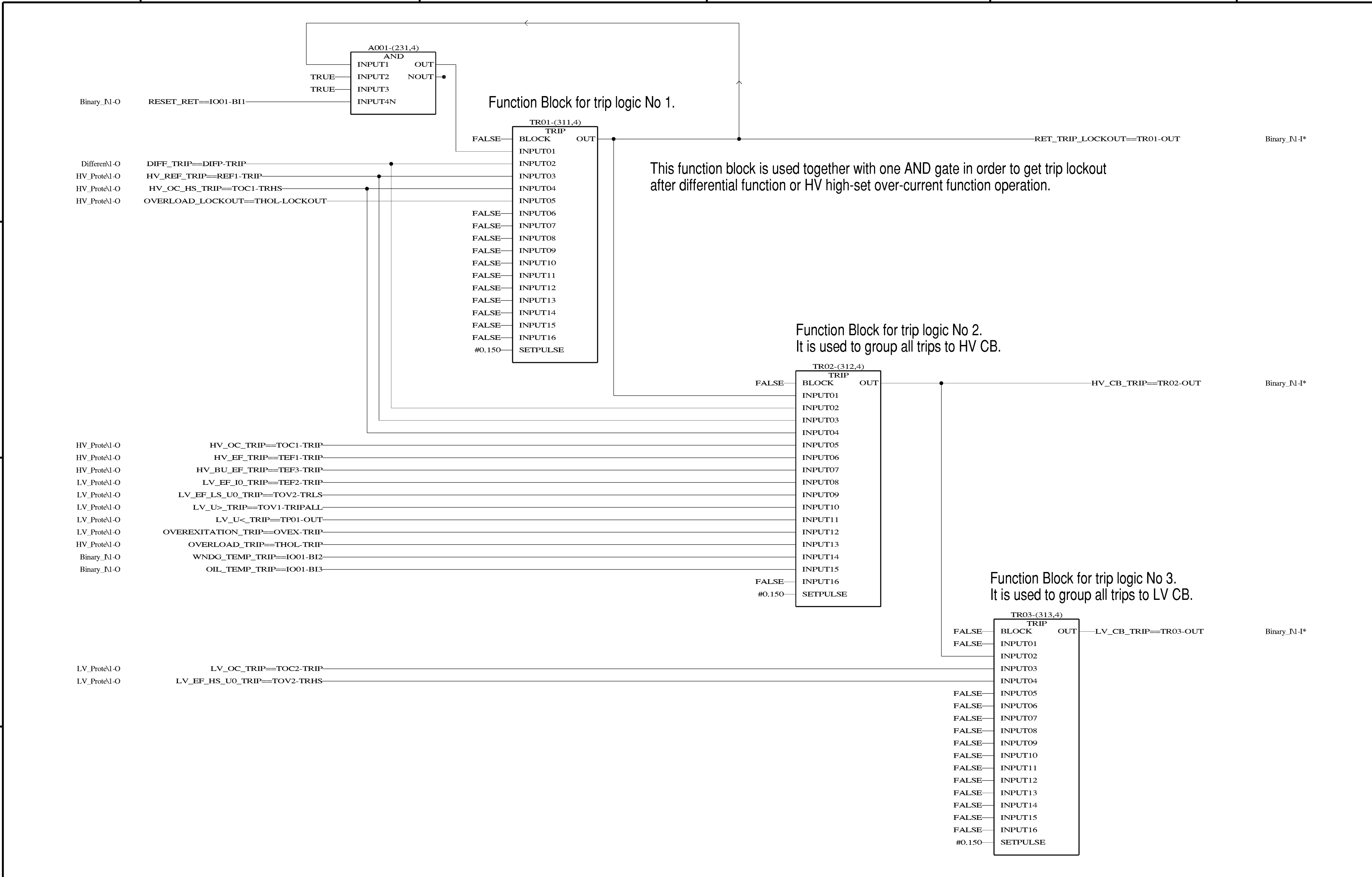
Prepared		02-04-15	RET 521 2p4	HV_Prote
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA · Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 1 · Sheet 1/1
Based on	Pcl			



PLEASE NOTE

that on all LV protection functions parameter SIDE2W must be set to value 2 in order to indicate to the respective function that it is connected to the LV (i.e. secondary) side of the power

Prepared		02-04-15	RET 521 2p4		LV_Prote
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 1	Sheet 1/1
Based on	Pcl				



Prepared		02-04-15	RET 521 2p4
Approved	Birger Hillström	02-04-20	
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB
Based on	Pcl		

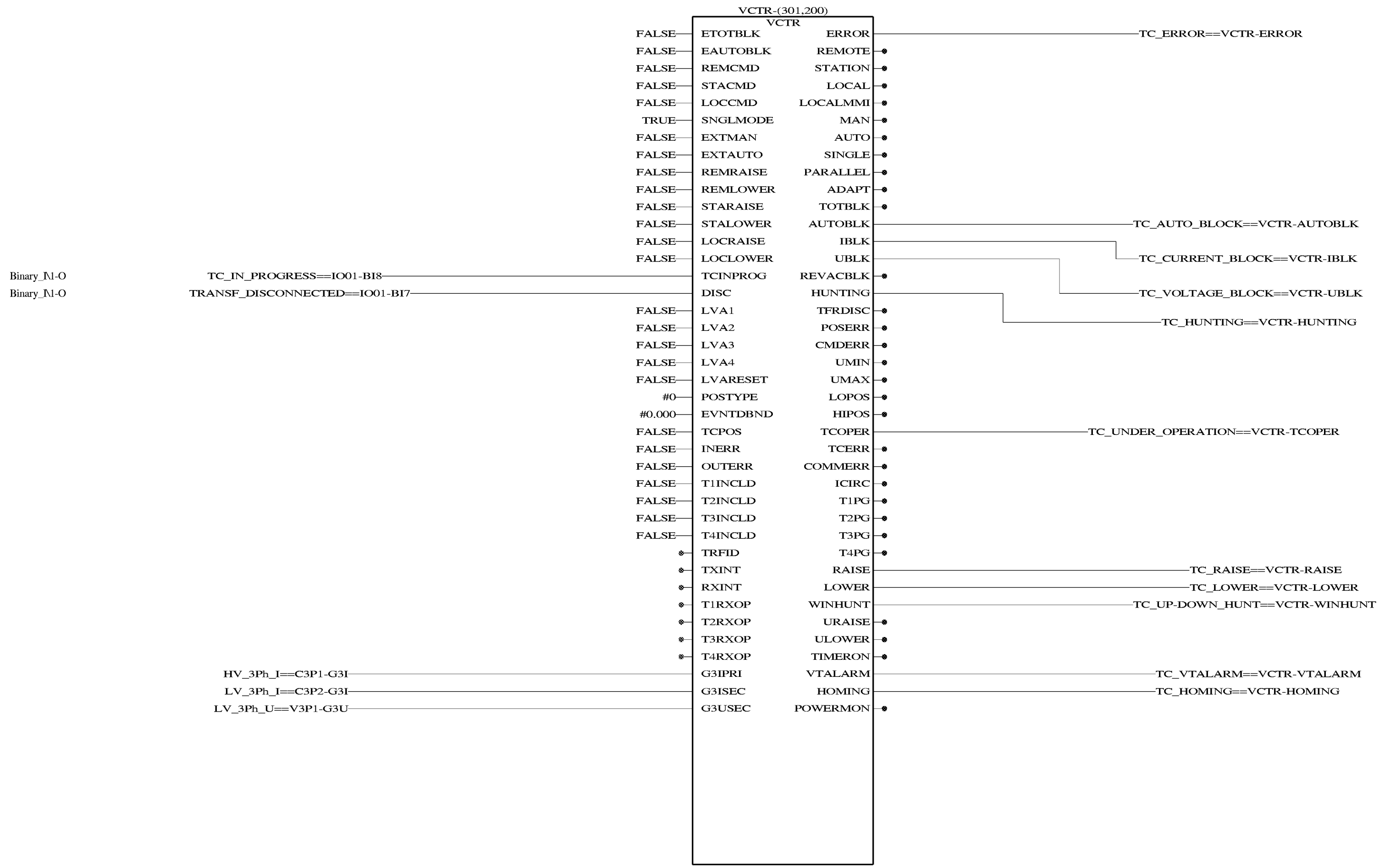
Trip_Log

Resp dep SA/ATA Rev Ind

Example 1

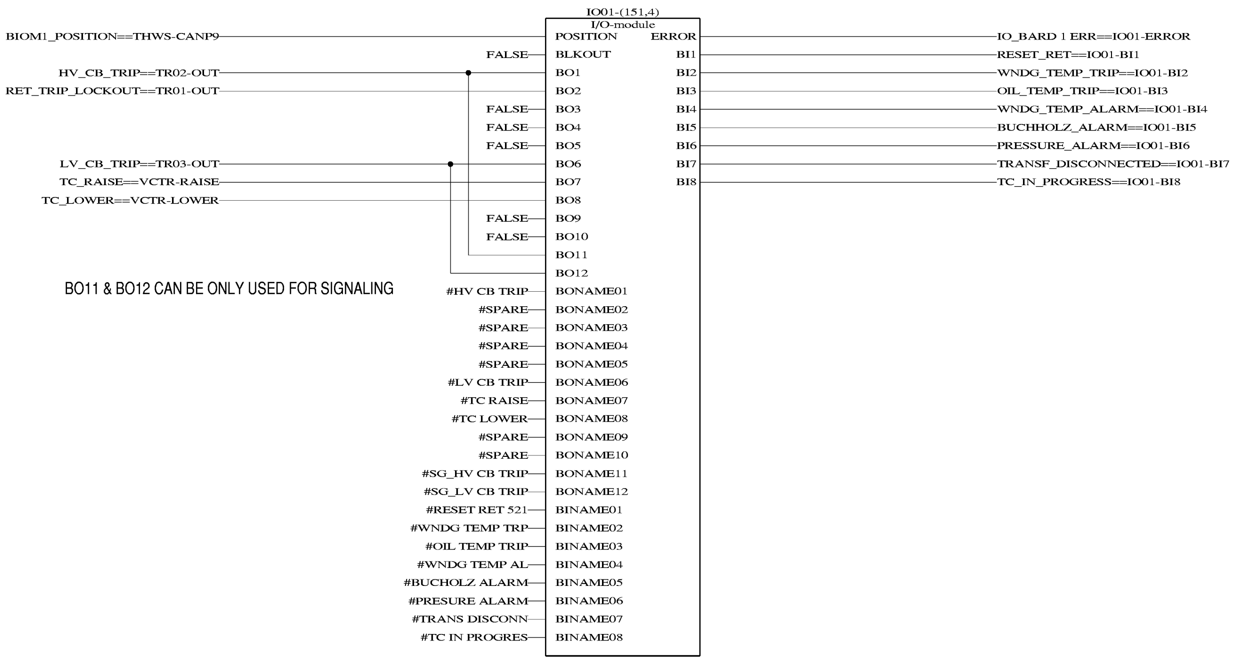
Sheet 1/1

Function Block for LV side voltage control function (i.e. tap changer control function).
VCTR for parallel operating transformers max 4 pieces



Prepared		02-04-15	RET 521 2p4		Voltage_
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 1	Sheet 1/1
Based on	Pcl				

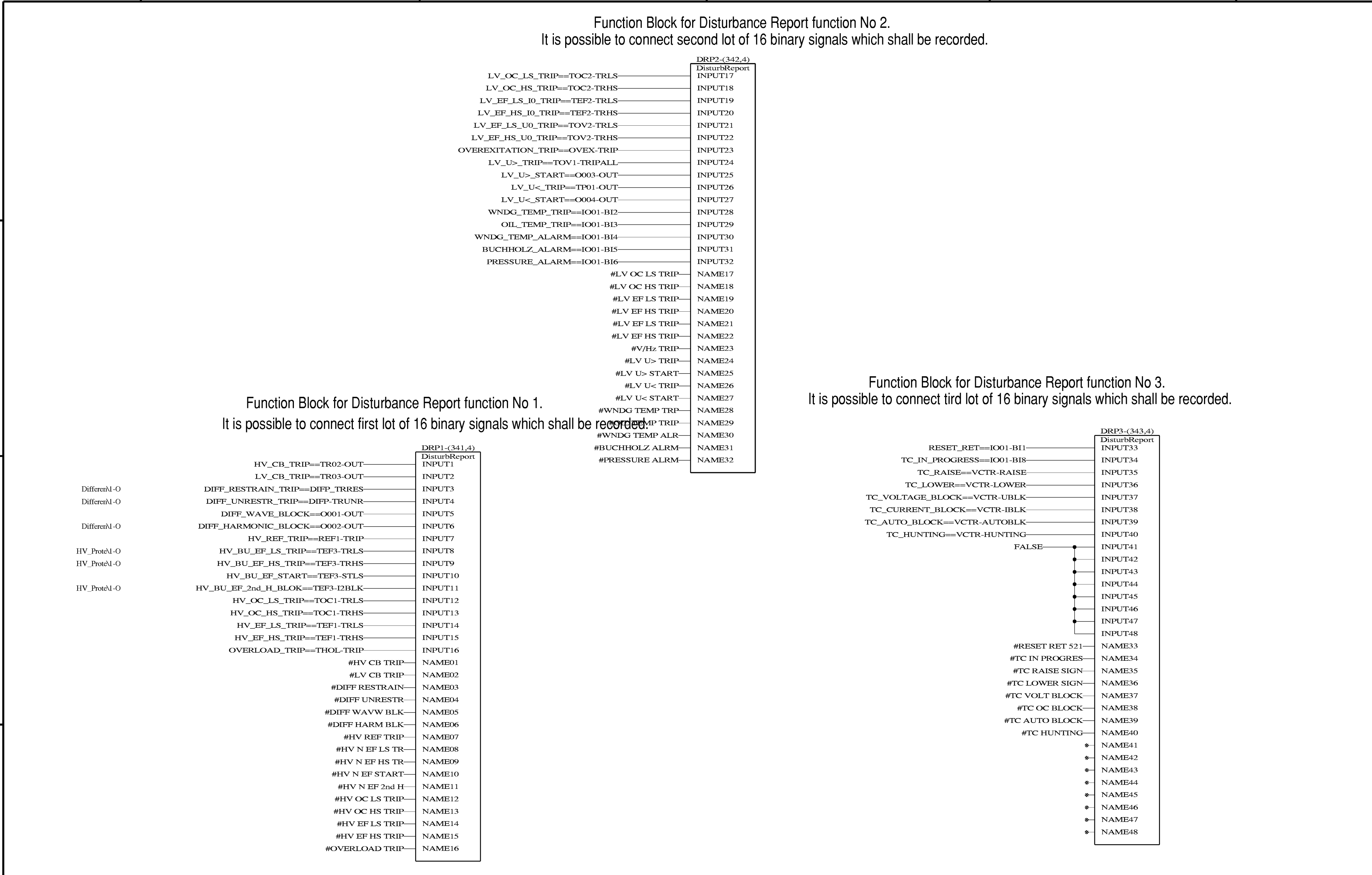
Function Block for Binary Input Output Module (IOM) with 8 optocoupler inputs and 12 contact outputs.



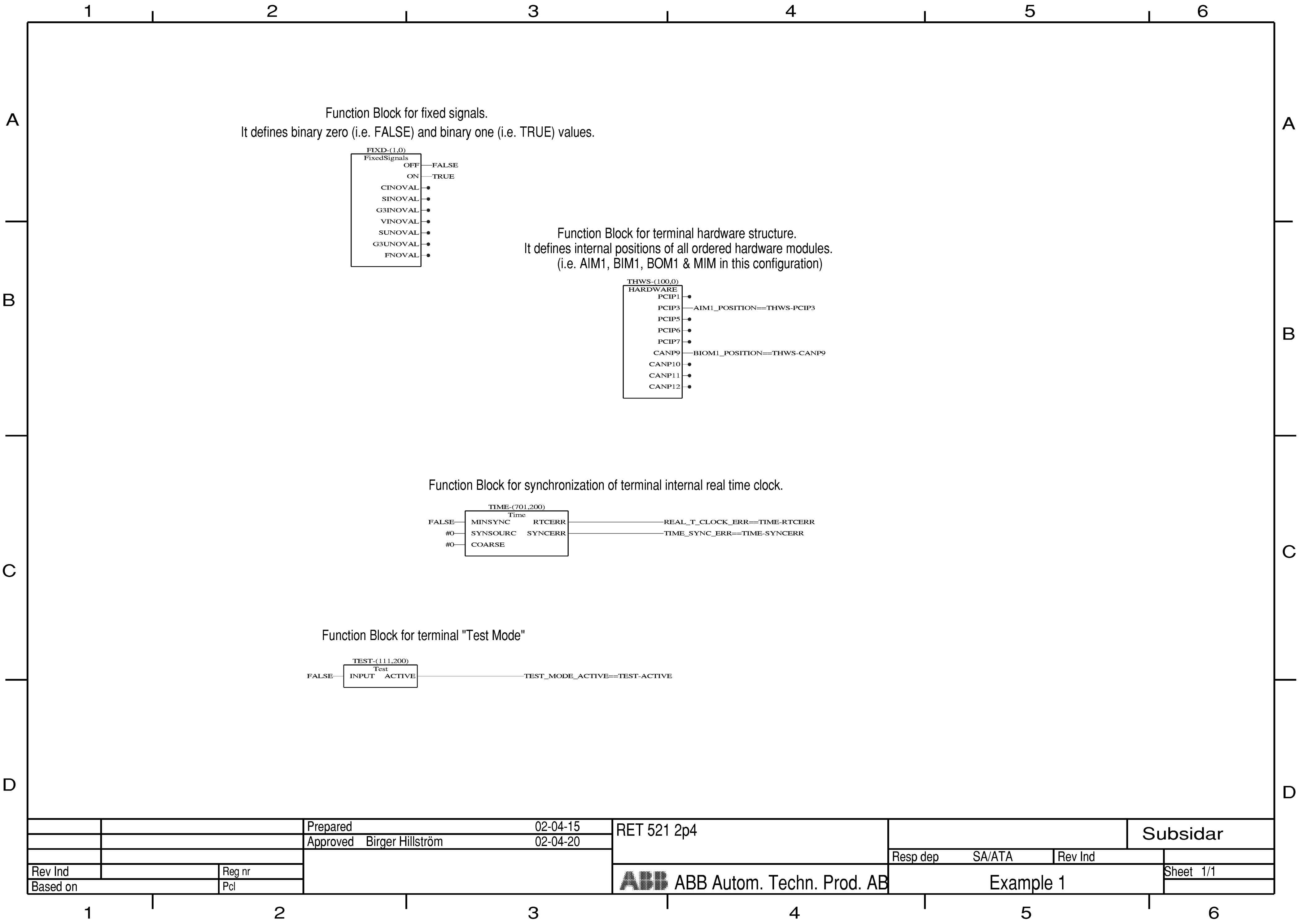
Prepared 02-04-15
Approved Birger Hillström 02-04-20
RET 521 2p4
Binary_I
Rev Ind
Reg nr
Based on
Pcl
ABB Autom. Techn. Prod. AB
Resp dep SA/ATA
Rev Ind
Example 1
Sheet 1/1

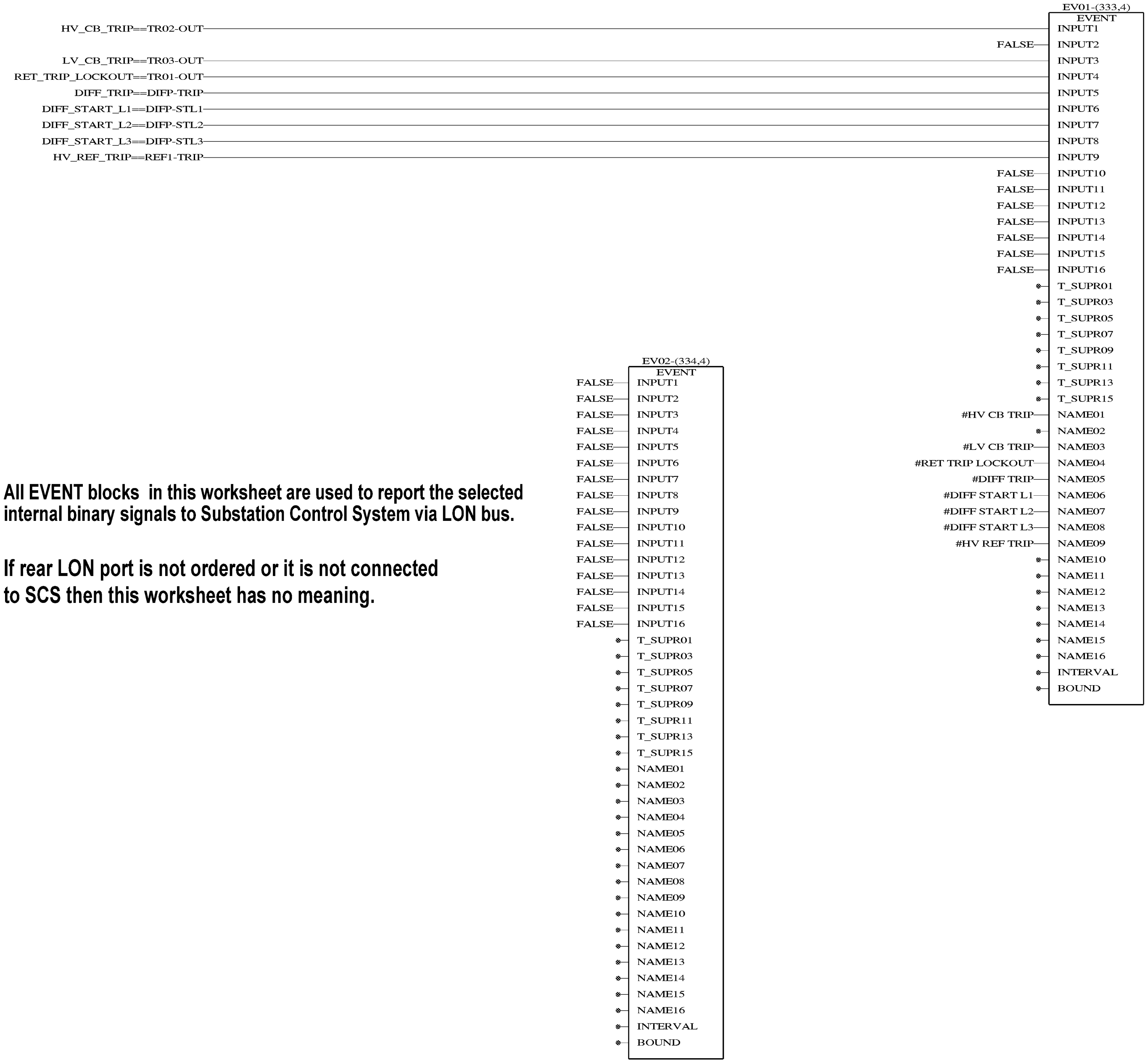
Function Block for Disturbance Report function.
It provides binary indication when new recording is made and when avaiable memory is used.

Rev Ind	Reg nr	Prepared	02-04-15	RET 521 2p4	Disturba
Based on	Pcl	Approved Birger Hillström	02-04-20	ABB Autom. Techn. Prod. AB	Resp dep SA/ATA Rev Ind
					Example 1 Sheet 1/2



Prepared		02-04-15	RET 521 2p4	Disturba
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA · Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 1 · Sheet 2/2
Based on	Pcl			

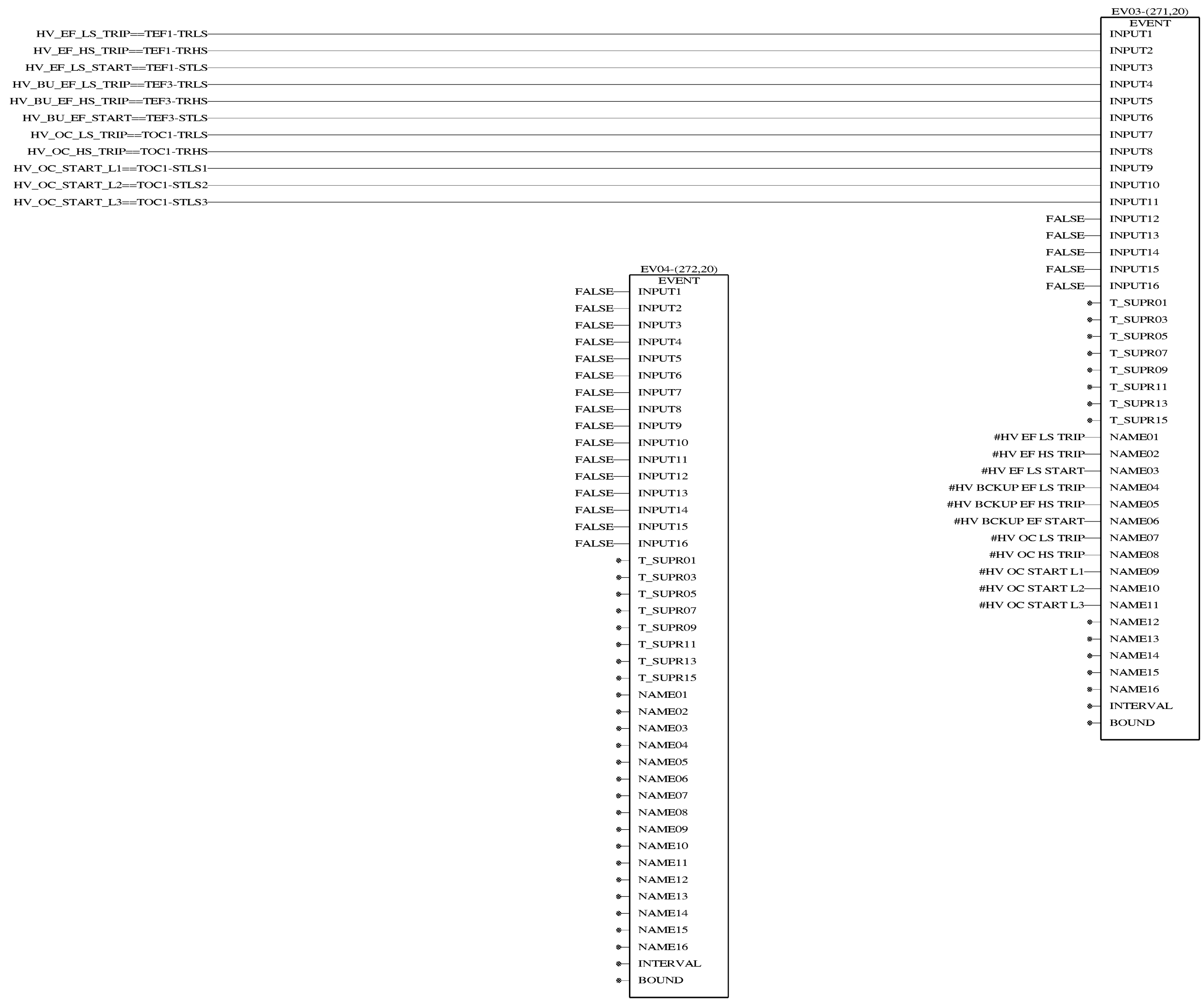

Function Block for fixed signals.
It defines binary zero (i.e. FALSE) and binary one (i.e. TRUE) values.
FIXD-(1,0)
FixedSignals
OFF
FALSE
ON
TRUE
CINOVAL
SINOVAL
G3INOVAL
VINOVAL
SUNOVAL
G3UNOVAL
FNOVAL
Function Block for terminal hardware structure.
It defines internal positions of all ordered hardware modules.
(i.e. AIM1, BIM1, BOM1 & MIM in this configuration)
THWS-(100,0)
HARDWARE
PCIP1
PCIP3
AIM1_POSITION==THWS-PCIP3
PCIP5
PCIP6
PCIP7
CANP9
BIOM1_POSITION==THWS-CANP9
CANP10
CANP11
CANP12
Function Block for synchronization of terminal internal real time clock.
TIME-(701,200)
Time
FALSE
MINSYNC
RTCERR
REAL_T_CLOCK_ERR==TIME-RTCERR
#0
SYNSOURC
SYNCERR
TIME_SYNC_ERR==TIME-SYNCERR
#0
COARSE
Function Block for terminal "Test Mode"
TEST-(111,200)
Test
FALSE
INPUT
ACTIVE
TEST_MODE_ACTIVE==TEST-ACTIVE
Prepared 02-04-15
Approved Birger Hillström 02-04-20
RET 521 2p4
Subsidar
Rev Ind
Reg nr
Based on
Pcl
Resp dep SA/ATA
Rev Ind
Sheet 1/1
ABB Autom. Techn. Prod. AB
Example 1



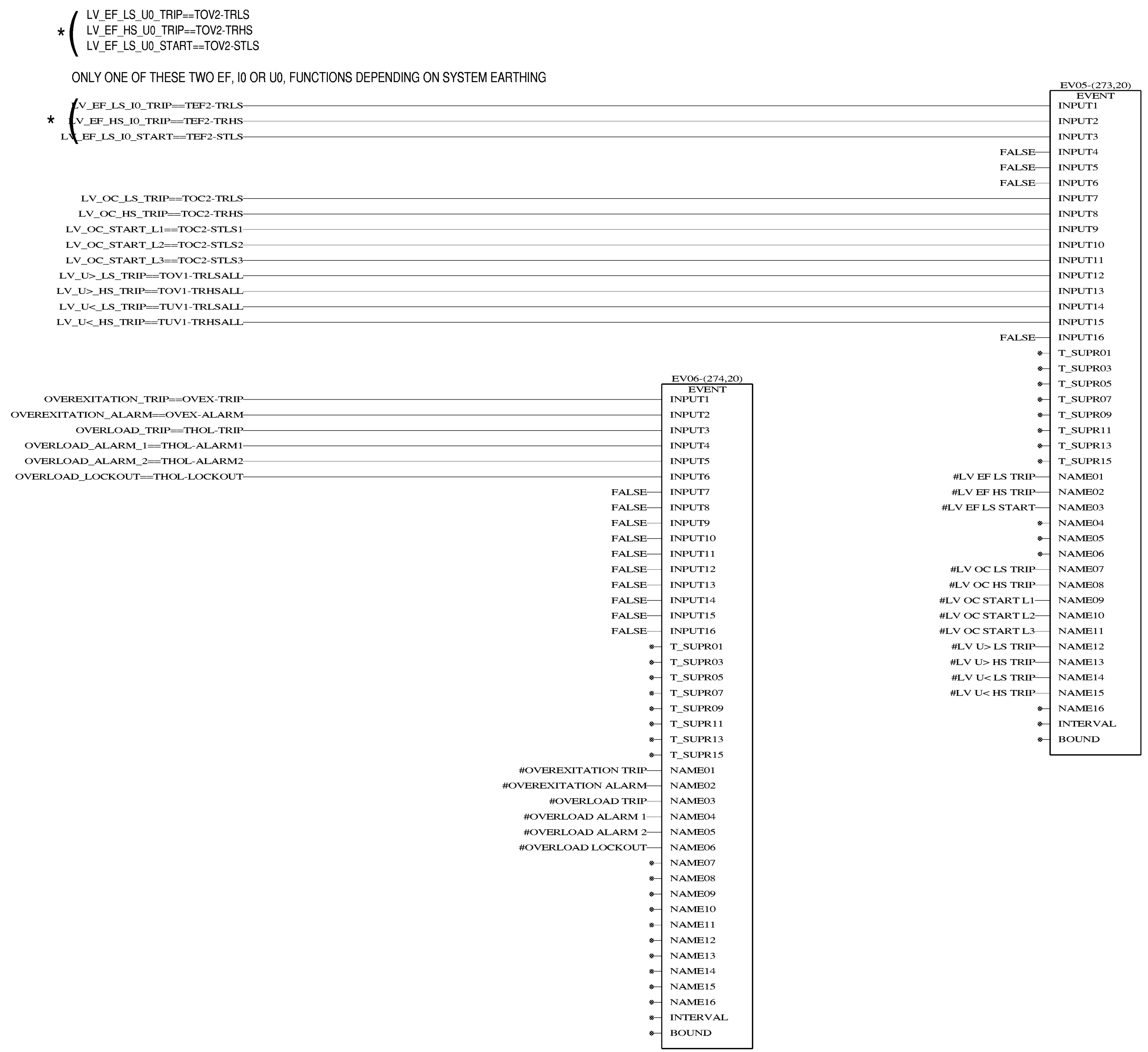
All EVENT blocks in this worksheet are used to report the selected internal binary signals to Substation Control System via LON bus.

If rear LON port is not ordered or it is not connected to SCS then this worksheet has no meaning.

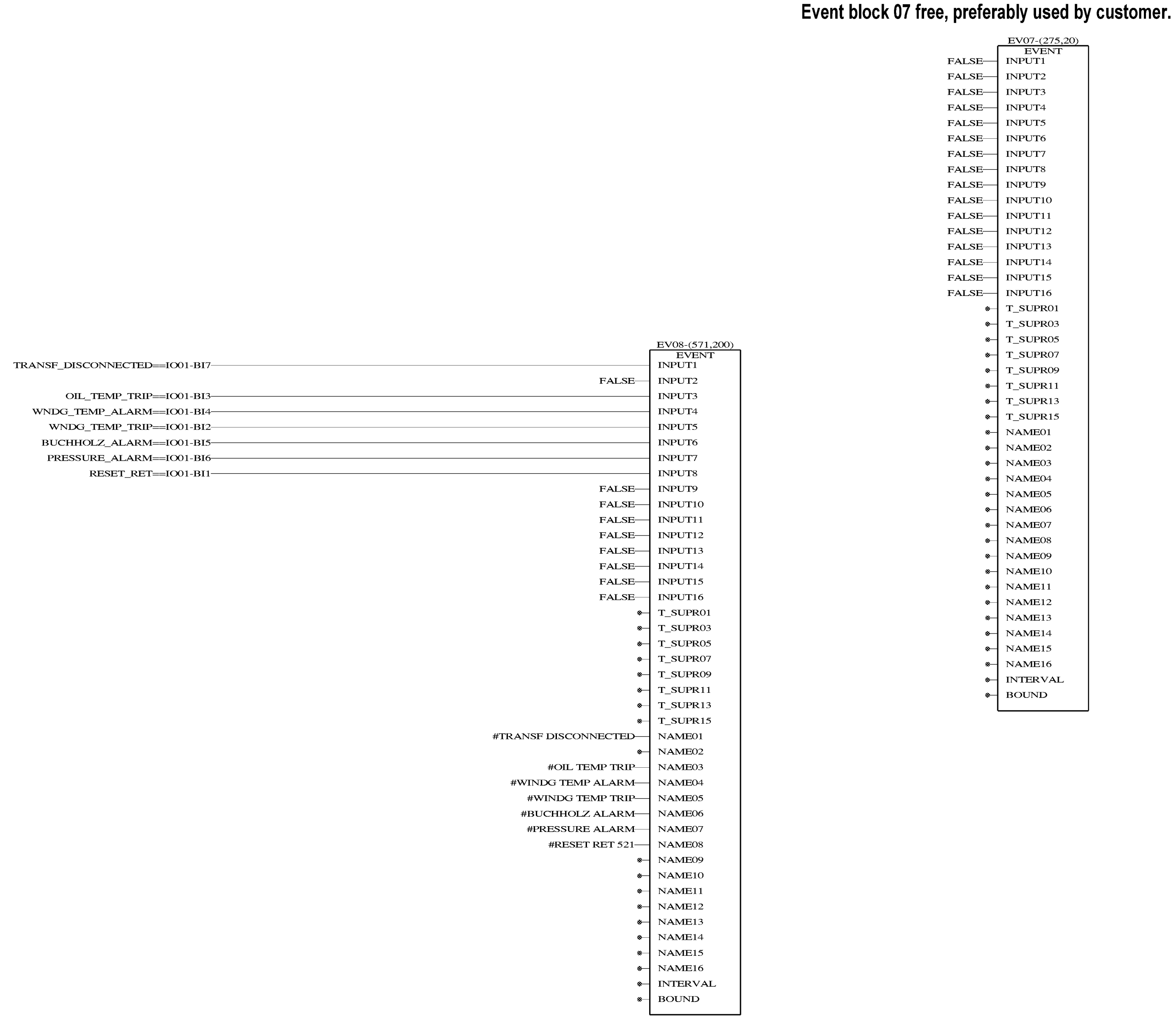
Prepared		02-04-15	RET 521 2p4	Events_v
Approved	Birger Hillström	02-04-20		
Rev Ind	Reg nr		Resp dep SA/ATA	Rev Ind
Based on	Pcl		ABB Autom. Techn. Prod. AB	Example 1
				Sheet 1/6



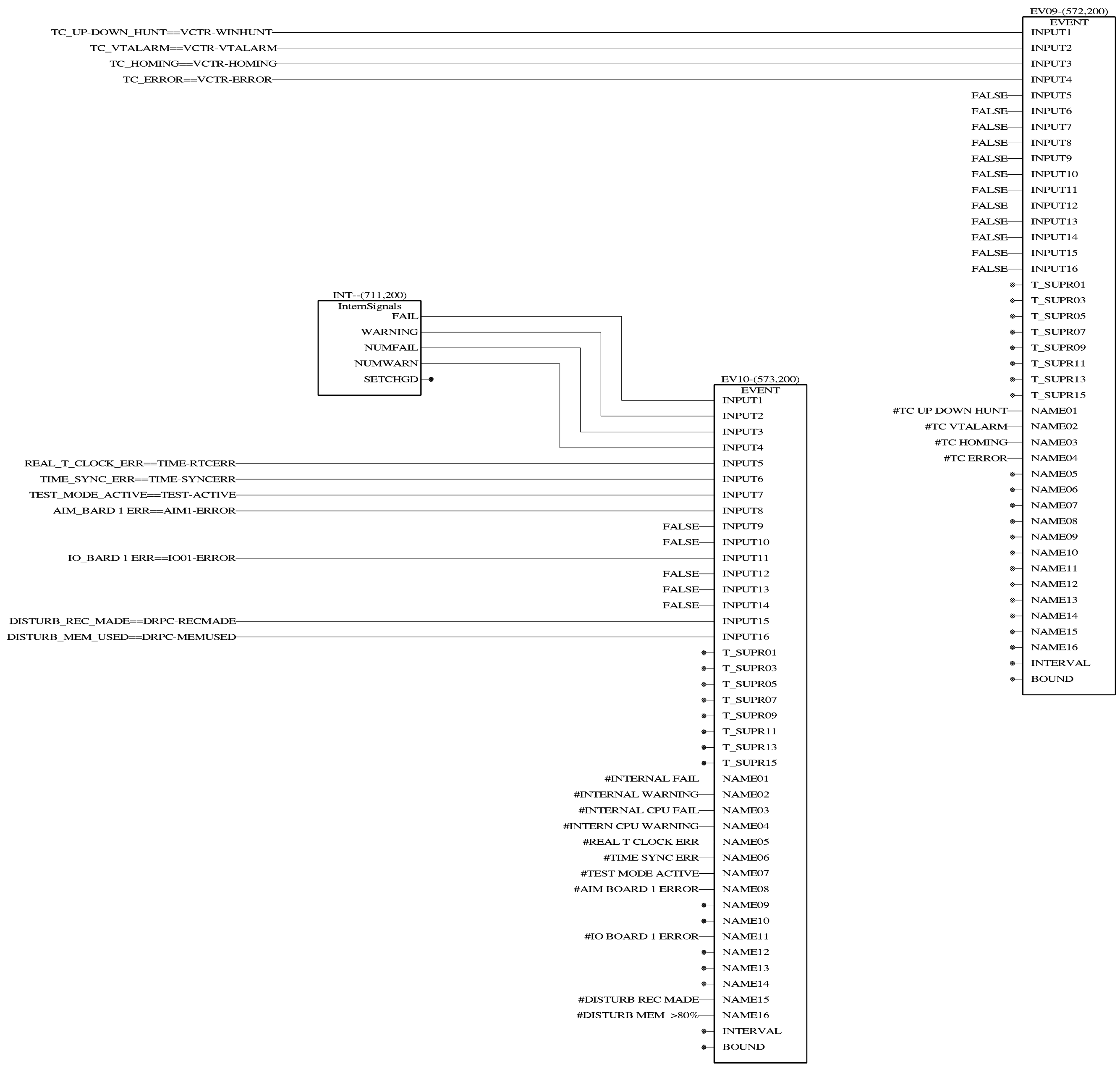
Prepared	02-04-15	RET 521 2p4	Events_v
Approved Birger Hillström	02-04-20		
Rev Ind / Reg nr		ABB Autom. Techn. Prod. AB	Resp dep SA/ATA, Rev Ind
Based on / Pcl			Example 1, Sheet 2/6



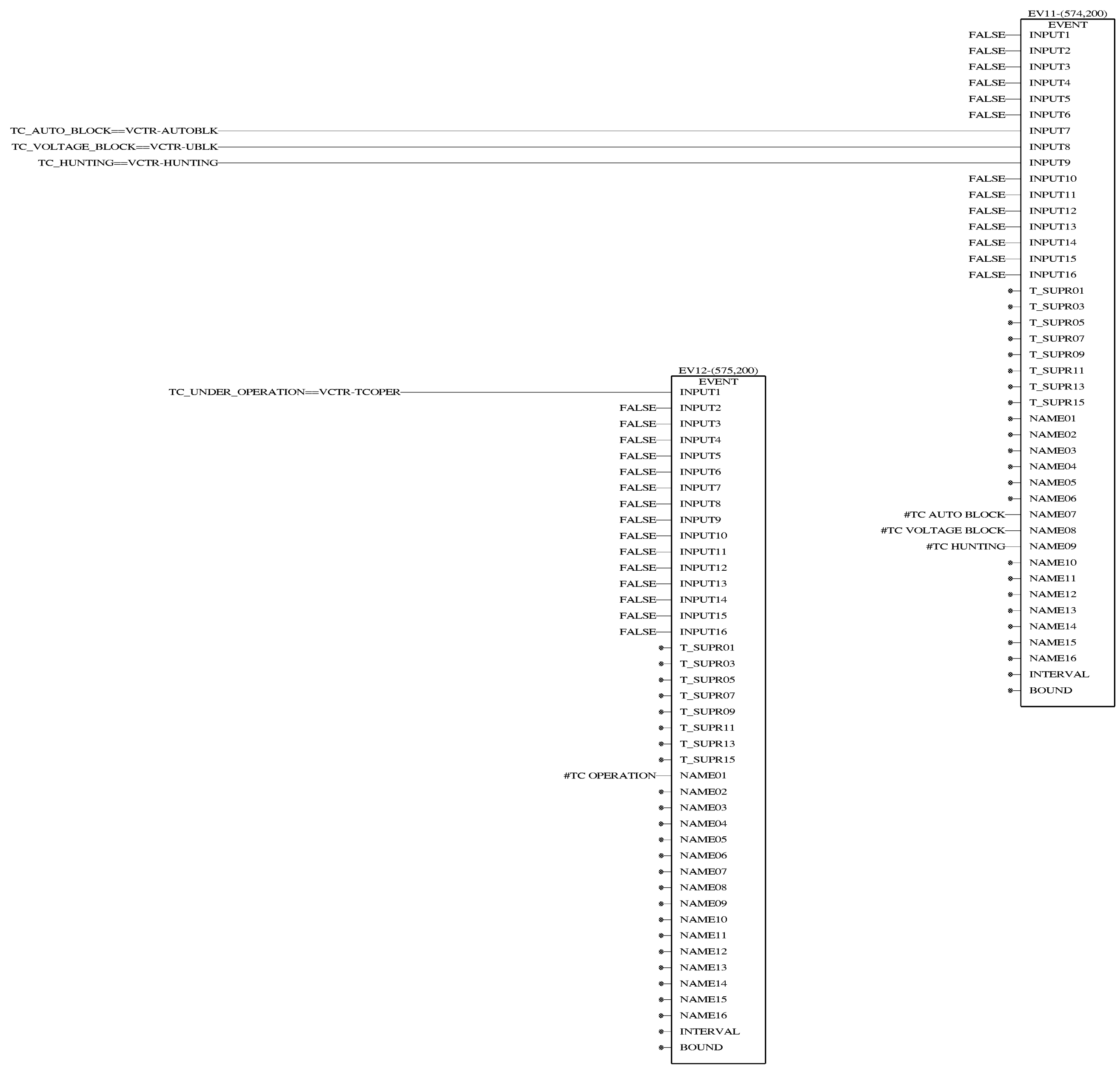
Prepared	02-04-15	RET 521 2p4	Events_v
Approved Birger Hillström	02-04-20		Resp dep SA/ATA Rev Ind
Rev Ind	Reg nr	ABB Autom. Techn. Prod. AB	Example 1
Based on	Pcl		Sheet 3/6



Prepared		02-04-15	RET 521 2p4	Events_v
Approved	Birger Hillström	02-04-20		
Rev Ind	Reg nr			Resp dep SA/ATA — Rev Ind
Based on	Pcl		ABB Autom. Techn. Prod. AB	Example 1 — Sheet 4/6



Prepared		02-04-15	RET 521 2p4		Events_v
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 1	Sheet 5/6
Based on	Pcl				



		Prepared	02-04-15	RET 521 2p4		Events_v
		Approved Birger Hillström	02-04-20			
					Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 1	Sheet 6/6
Based on	Pcl					

Description Example Config no 2 (1MRK 001 536-23)	Work Sheet No
List of Content	Sheet No 01
Short Configuration Description	Sheet No 02
Configuration of Current & Voltage Signals	Sheet No 03
Reading of Tap Position via mA input signal	Sheet No 04
Differential Protection Function	Sheet No 05
HV Protection Functions	Sheet No 06
LV Protection Functions	Sheet No 07 & 08
Tripping Logic	Sheet No 09
Voltage Control Function	Sheet No 10
Configuration of Binary Input/Output Module	Sheet No 11
Configuration of Disturbance Report	Sheet No 12 & 13
Subsidary Configuration	Sheet No 14 & 15
Configuration of Event Reporting via LON bus	Sheet No 16 to 21

Short configuration description

The example configuration No 2 is made for protection and control of a two winding power transformer.

In the RET 521 terminal the following hardware modules are included: one AIM (8I+2U), one IOM & one MIM.

It is assumed that 3-Ph HV currents are connected to analogue inputs 1, 2 & 3 and HV neutral current to analogue input 7; 3-Ph LV currents are connected to analogue inputs 4, 5 & 6 and LV neutral current to analogue input 8.

To the analogue input 9 LV phase-to-phase voltage (UL1-L2) is connected, while to input 10 LV open delta is connected.

The tap changer with 17 positions is located on the HV winding. Its position is monitored via 4-20mA analogue signal.

The following protection and control function are included in the configuration:

Transformer bias differential protection (87T & 87H); HV winding & LV winding restricted EF protection (87N)
HV & LV 3-Ph OC protection (50, 51); HV & LV EF protection (50N, 51N); LV Stand-by EF protection (50N, 51N);
HV thermal overload (49); LV U< protection (27); LV U> protection (59); LV Uo> protection (59N); Overexcitation protection (24) and LV side voltage control (90).

Individual tripping logic for CBs on both transformer sides are provided.

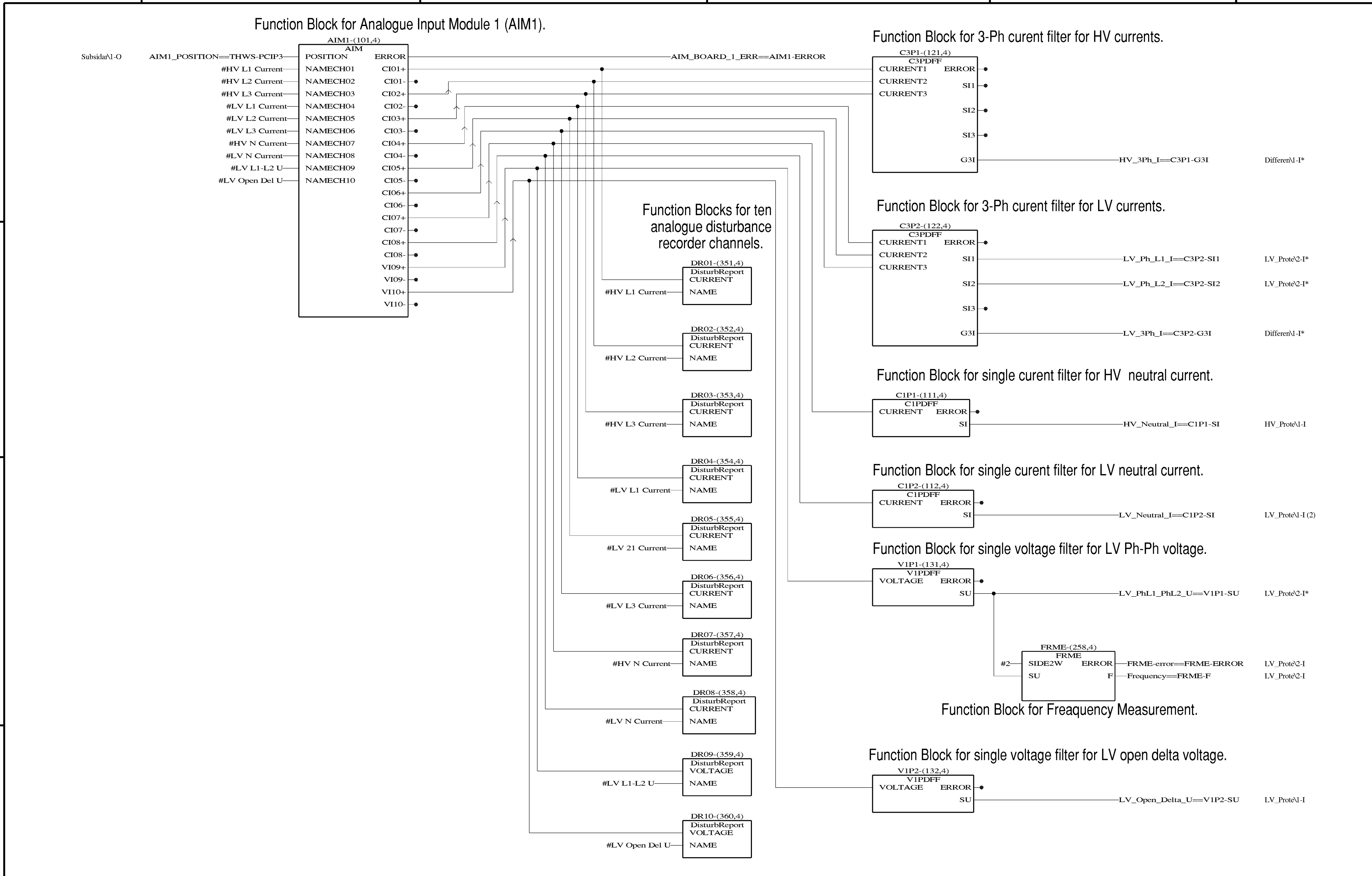
The tap changer with 17 positions is located on the HV winding. Its position is monitored via 4-20mA analogue signal.

All 10 analogue input signals are connected to the disturbance recorder. In addition to that 48 binary signals are connected to the disturbance recorder as well.

All required inputs and outputs from/to tap changer mechanism are configured.

Finally binary events to the substation control system which will be automatically reported via LON bus are configured.

Prepared		02-04-15	RET521 2p4	Overall_
Approved	Birger Hillström	02-04-20		
Rev Ind	Reg nr		Resp dep SA/ATA	Rev Ind
Based on	Pcl		ABB Autom. Techn. Prod. AB	Example 2	Sheet 2/2



Prepared		02-04-15	RET521 2p4
Approved	Birger Hillström	02-04-20	
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB
Based on	Pcl		

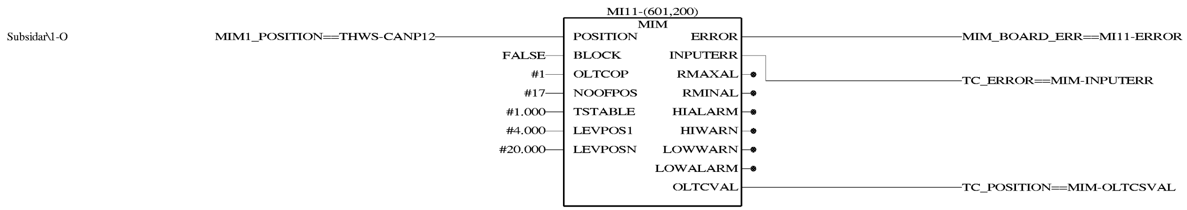
Analogue

Resp dep SA/ATA | Rev Ind

Example 2

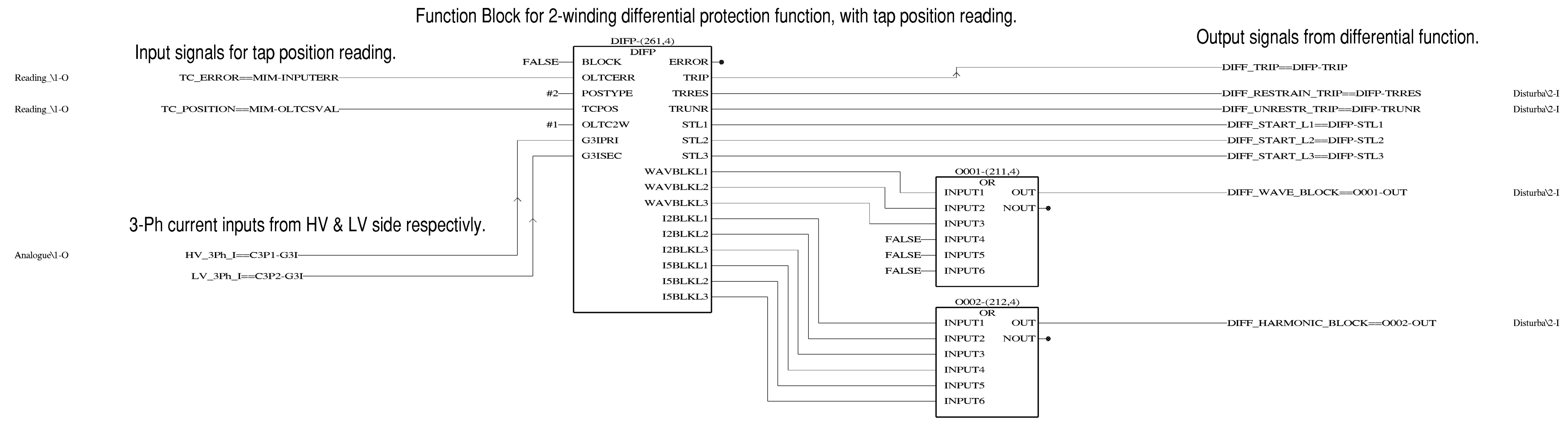
Sheet 1/1

Function Block for mA Input Module (MIM), input channel 1.

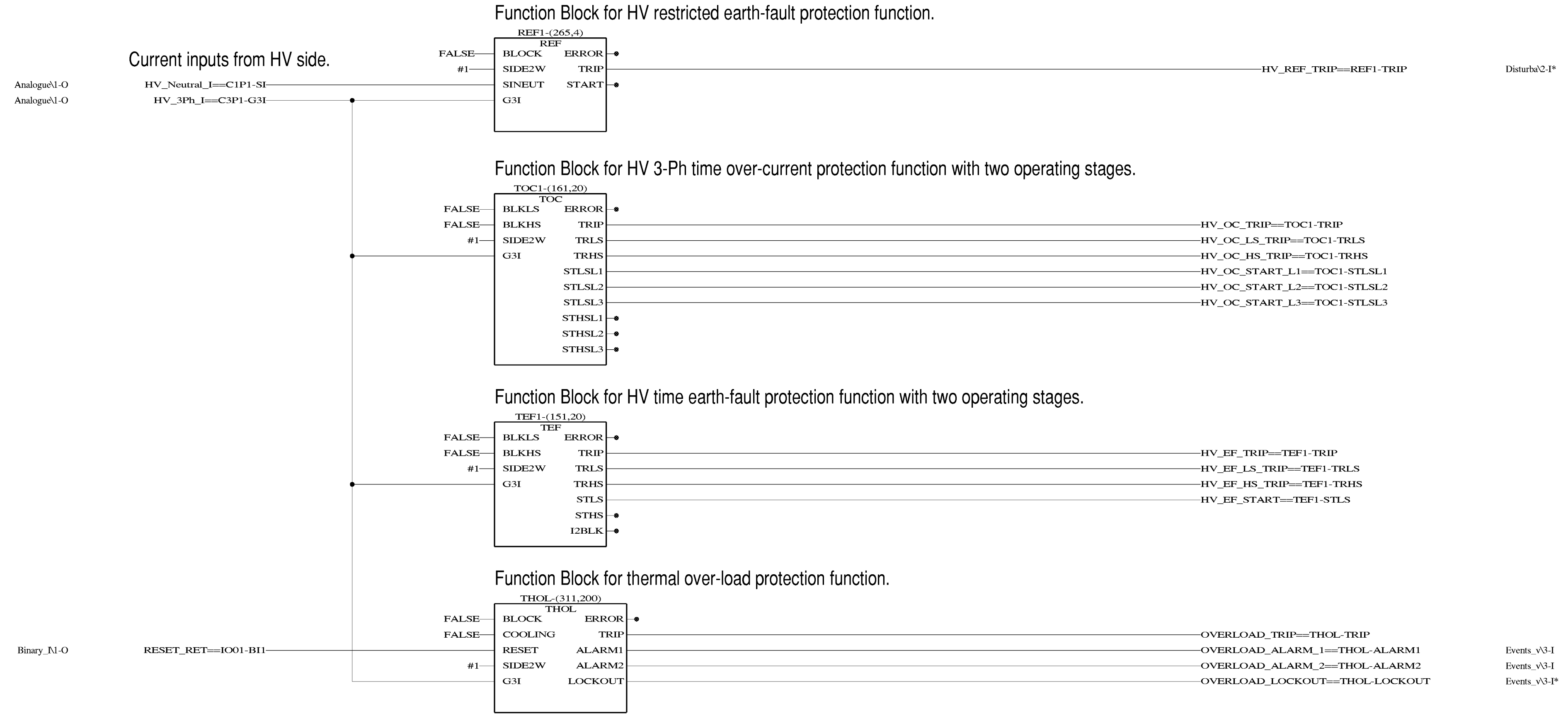


This function block is used here to convert 4-20mA input signal into 17 tap positions.
Value of tap position is then given to differential protection function and
voltage control function in order to enhance their functionality.

Prepared	02-04-15	RET521 2p4	Reading_
Approved Birger Hillström	02-04-20		Resp dep SA/ATA / Rev Ind
Rev Ind / Reg nr		ABB Autom. Techn. Prod. AB	Example 2 / Sheet 1/1
Based on / Pcl			

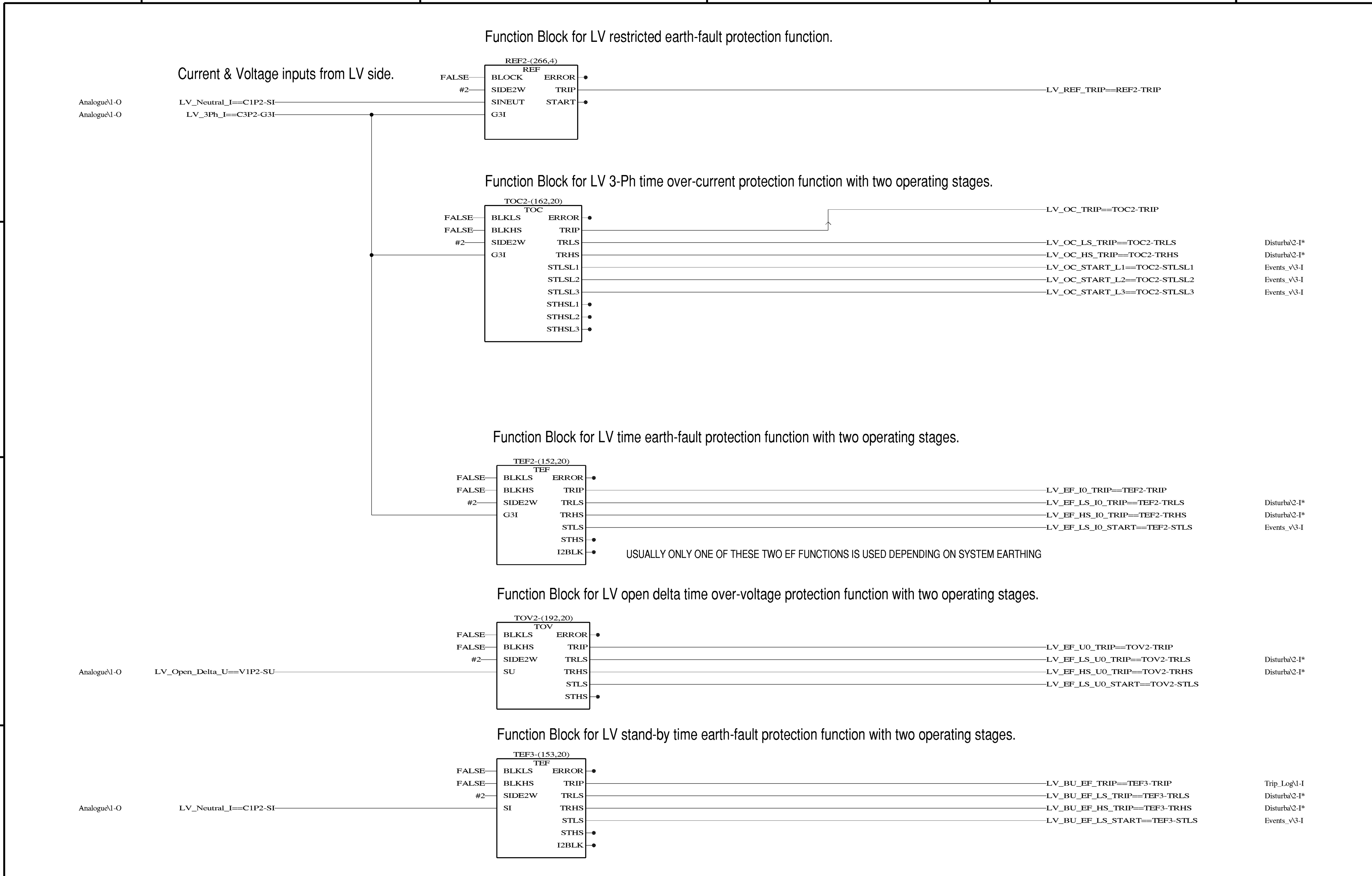


		Prepared	02-04-15	RET521 2p4	Differen
		Approved Birger Hillström	02-04-20		
					Resp dep SA/ATA, Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 2, Sheet 1/1
Based on	Pcl				

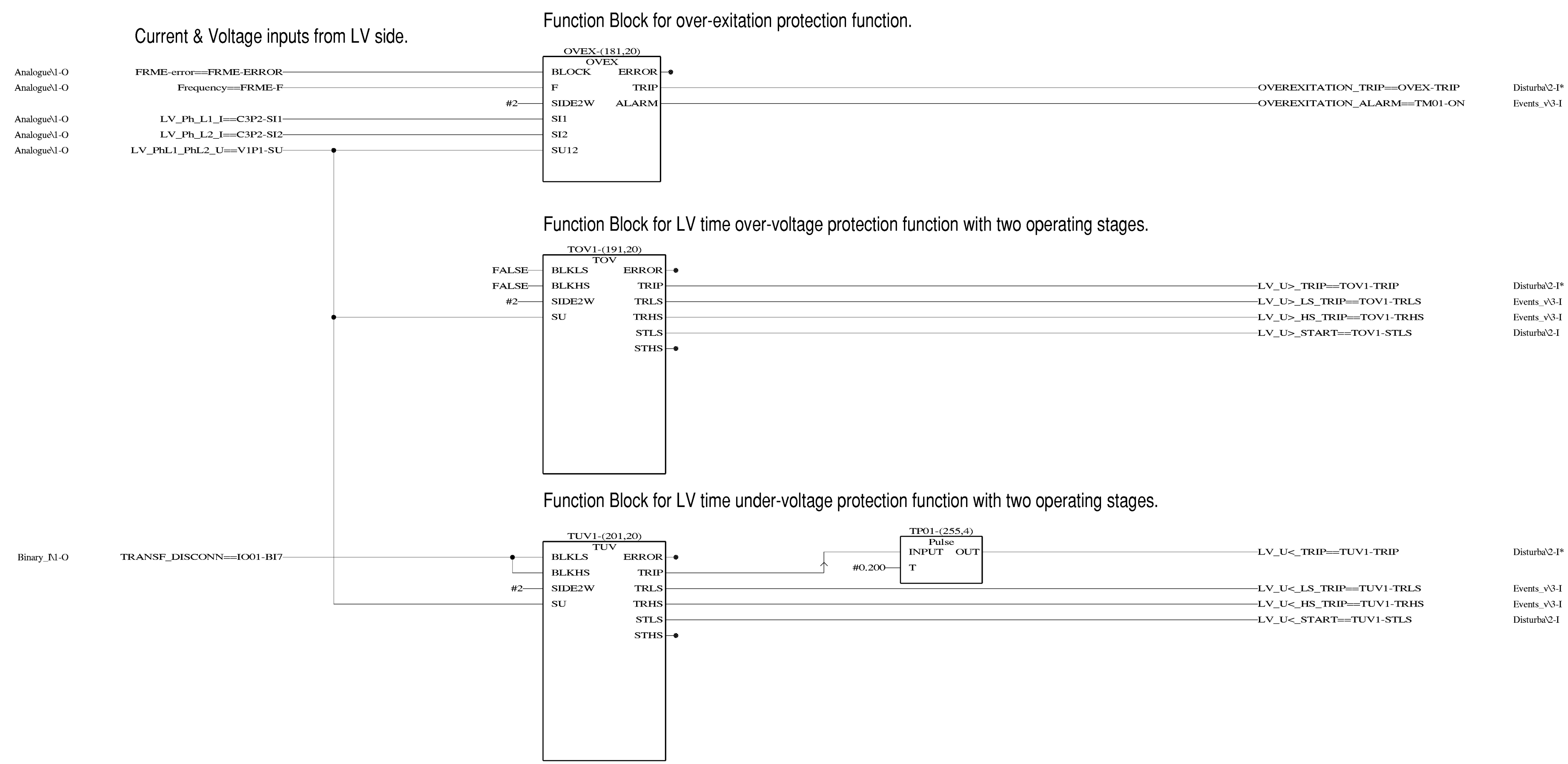


PLEASE NOTE that on all HV protection functions parameter SIDE3W must be set to value 1 in order to indicate to the respective function that it is connected to the HV (i.e. primary) side of the power transformer.

Prepared		02-04-15	RET521 2p4		HV_Prote
Approved	Birger Hillström	02-04-20			
Rev Ind	Reg nr			Resp dep SA/ATA	Rev Ind
Based on	Pcl		ABB Autom. Techn. Prod. AB	Example 2	Sheet 1/1

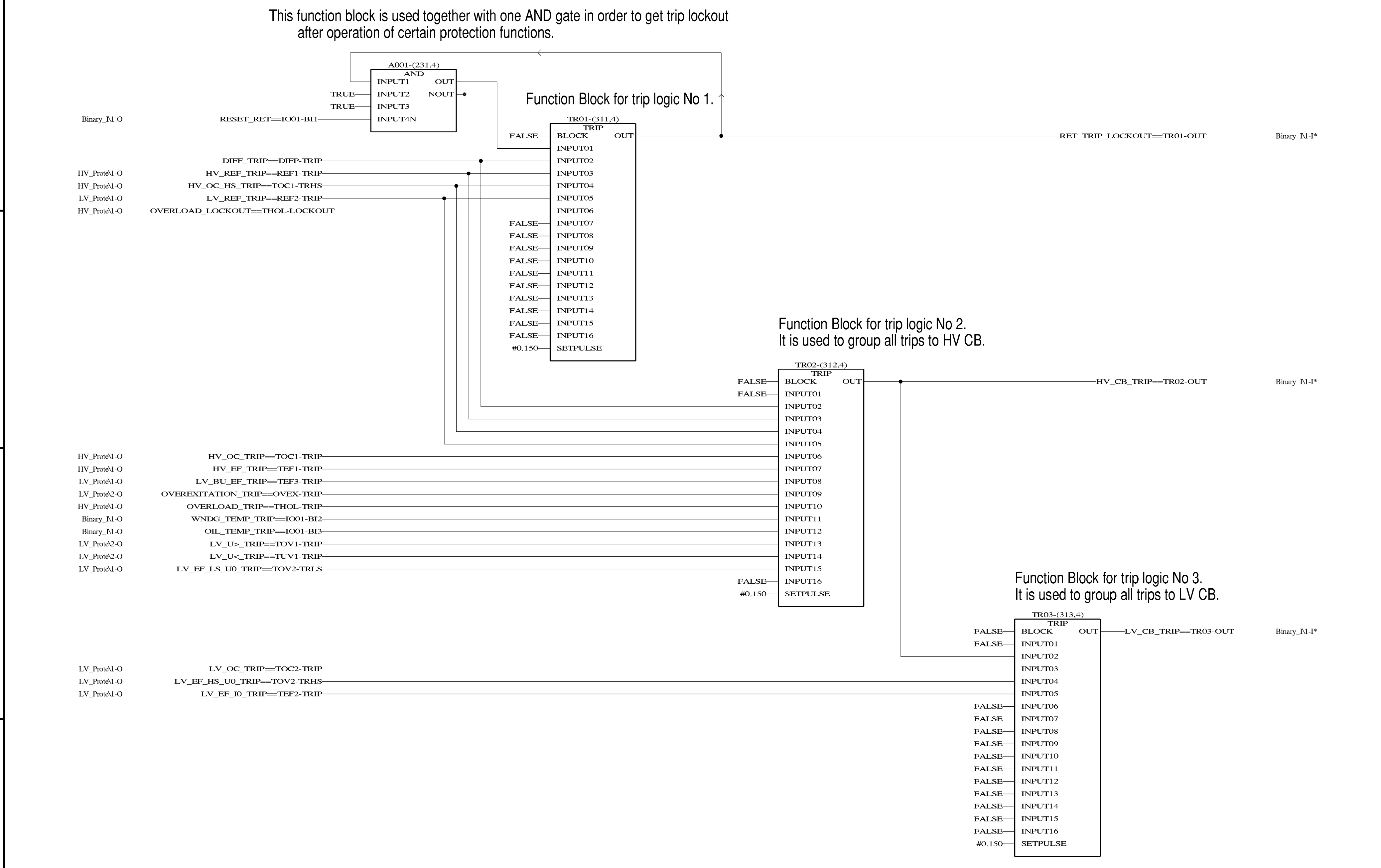


Prepared		02-04-15	RET521 2p4	LV_Prote
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA · Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 2 · Sheet 1/2
Based on	Pcl			



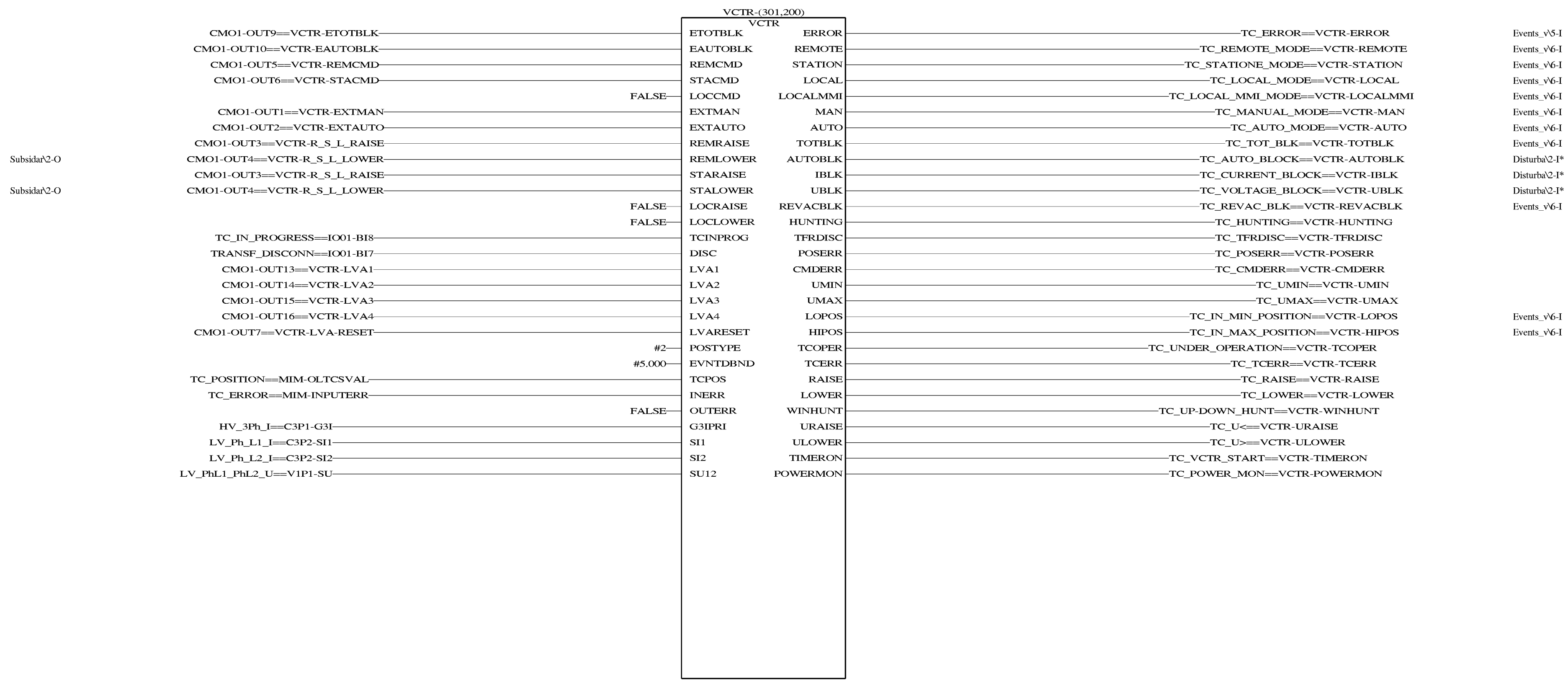
PLEASE NOTE that on all LV protection functions parameter SIDE2W must be set to value 2 in order to indicate to the respective function that it is connected to the LV (i.e. secondary) side of the power transformer.

Prepared		02-04-15	RET521 2p4		LV_Prote
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 2	Sheet 2/2
Based on	Pcl				



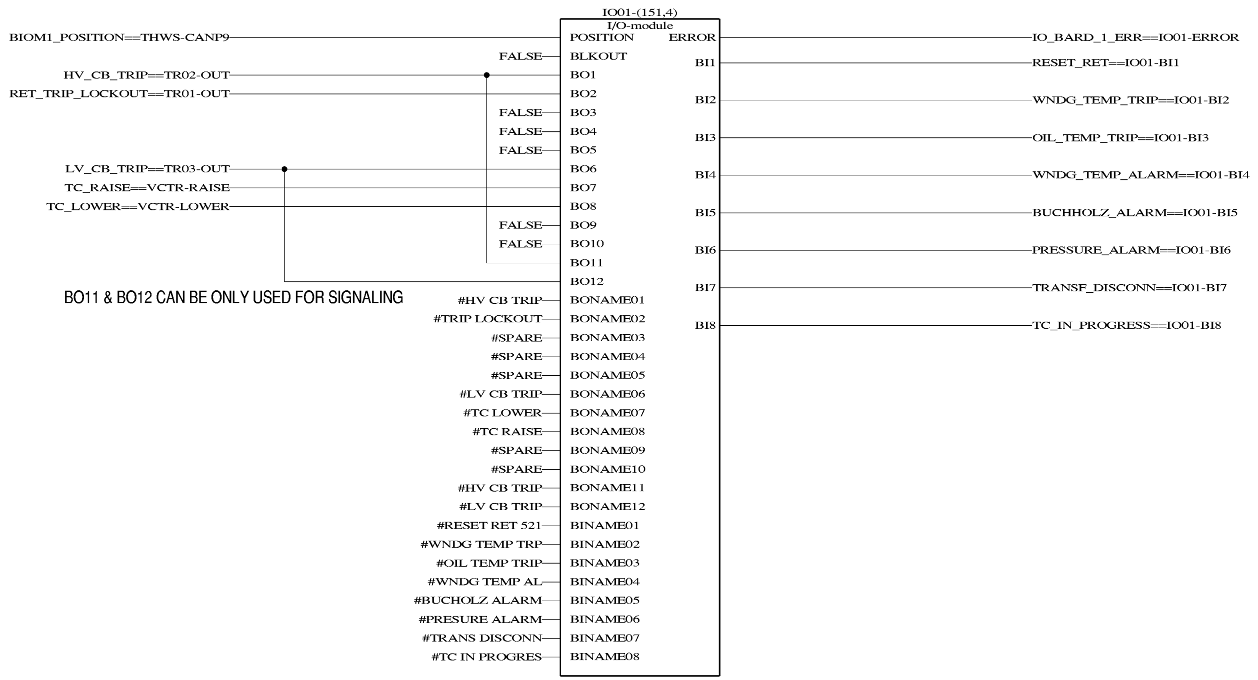
Prepared		02-04-15	RET521 2p4	Trip_Log
Approved	Birger Hillström	02-04-20		
Rev Ind	Reg nr		Resp dep SA/ATA	Rev Ind
Based on	Pcl		ABB Autom. Techn. Prod. AB	Example 2
				Sheet 1/1

Function Block for LV side voltage control function (i.e. tap changer control function).
VCTR single for one transformer



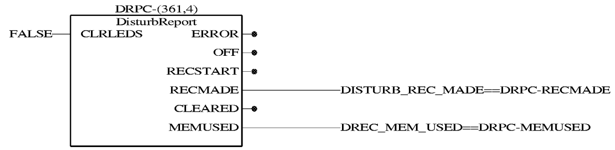
Prepared	02-04-15	RET521 2p4	Voltage_
Approved Birger Hillström	02-04-20		Resp dep SA/ATA Rev Ind
Rev Ind / Reg nr		ABB Autom. Techn. Prod. AB	Example 2 Sheet 1/1
Based on / Pcl			

Function Block for Input Output Module (IOM) with 8 optocoupler inputs and 12 optocoupler outputs.



		Prepared	02-04-15	RET521 2p4		Binary_I
		Approved Birger Hillström	02-04-20			
					Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 2	Sheet 1/1
Based on	Pcl					

Function Block for Disturbance Report function.
It provides binary indication when new recording is made and when avaiable memory is used.



Rev Ind		Reg nr	Prepared		02-04-15
Based on		Pcl	Approved	Birger Hillström	02-04-20

RET521 2p4

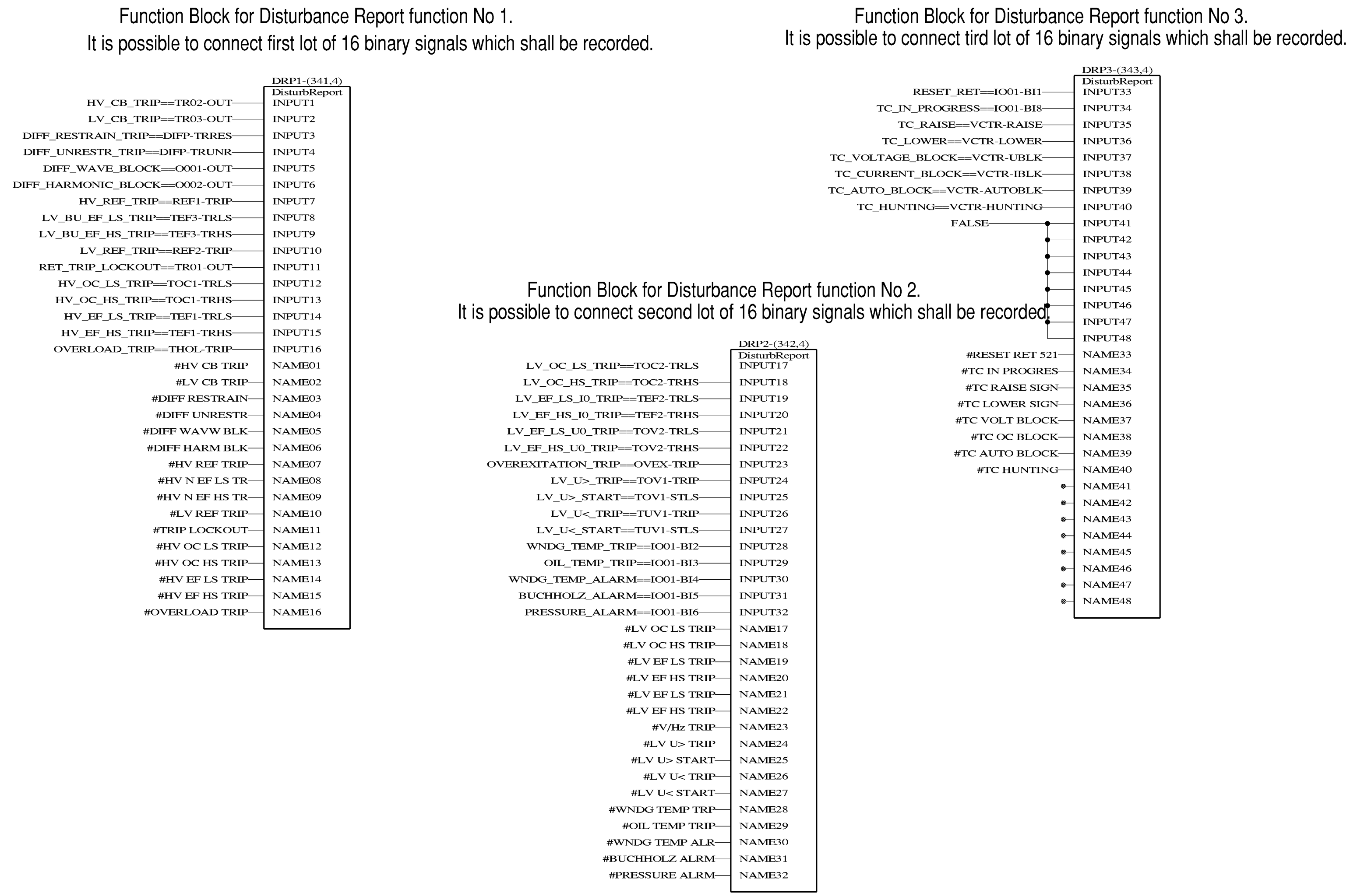
ABB Autom. Techn. Prod. AB

Resp dep SA/ATA Rev Ind

Example 2

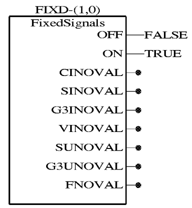
Disturba

Sheet 1/2

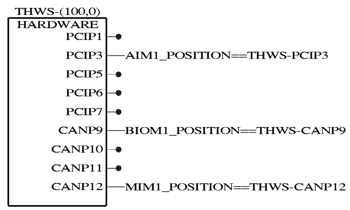


		Prepared	02-04-15	RET521 2p4	Disturba
		Approved Birger Hillström	02-04-20		
					Resp dep SA/ATA Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 2 — Sheet 2/2
Based on	Pcl				

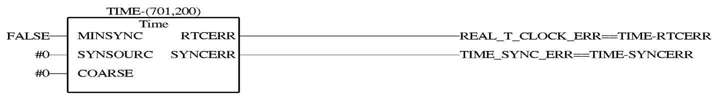
Function Block for fixed signals.
It defines binary zero (i.e. FALSE) and binary one (i.e. TRUE) values.



Function Block for terminal hardware structure.
It defines internal positions of all ordered hardware modules.
(i.e. AIM1, BIM1, BOM1 & MIM in this configuration)



Function Block for synchronization of terminal internal real time clock.



Function Block for terminal "Test Mode"

Prepared		02-04-15
Approved	Birger Hillström	02-04-20

Rev Ind | Reg nr
Based on | Pcl

RET521 2p4

ABB Autom. Techn. Prod. AB

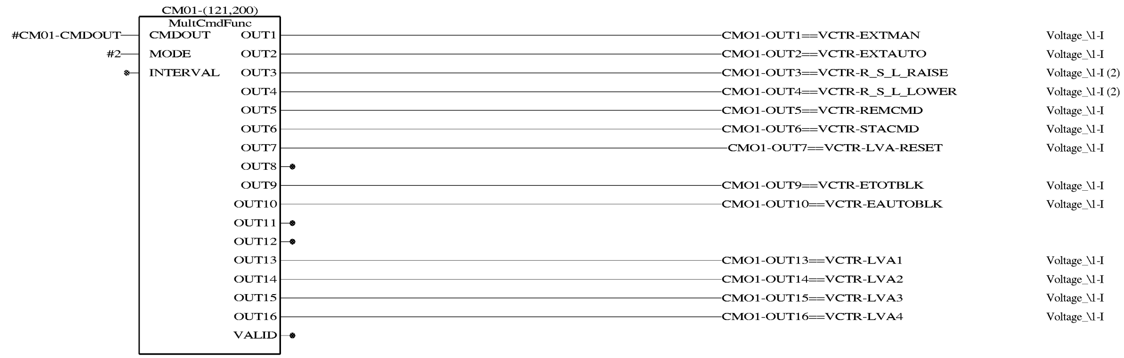
Subsidar

Resp dep SA/ATA | Rev Ind

Example 2

Sheet 1/2

Function Block for single command block.

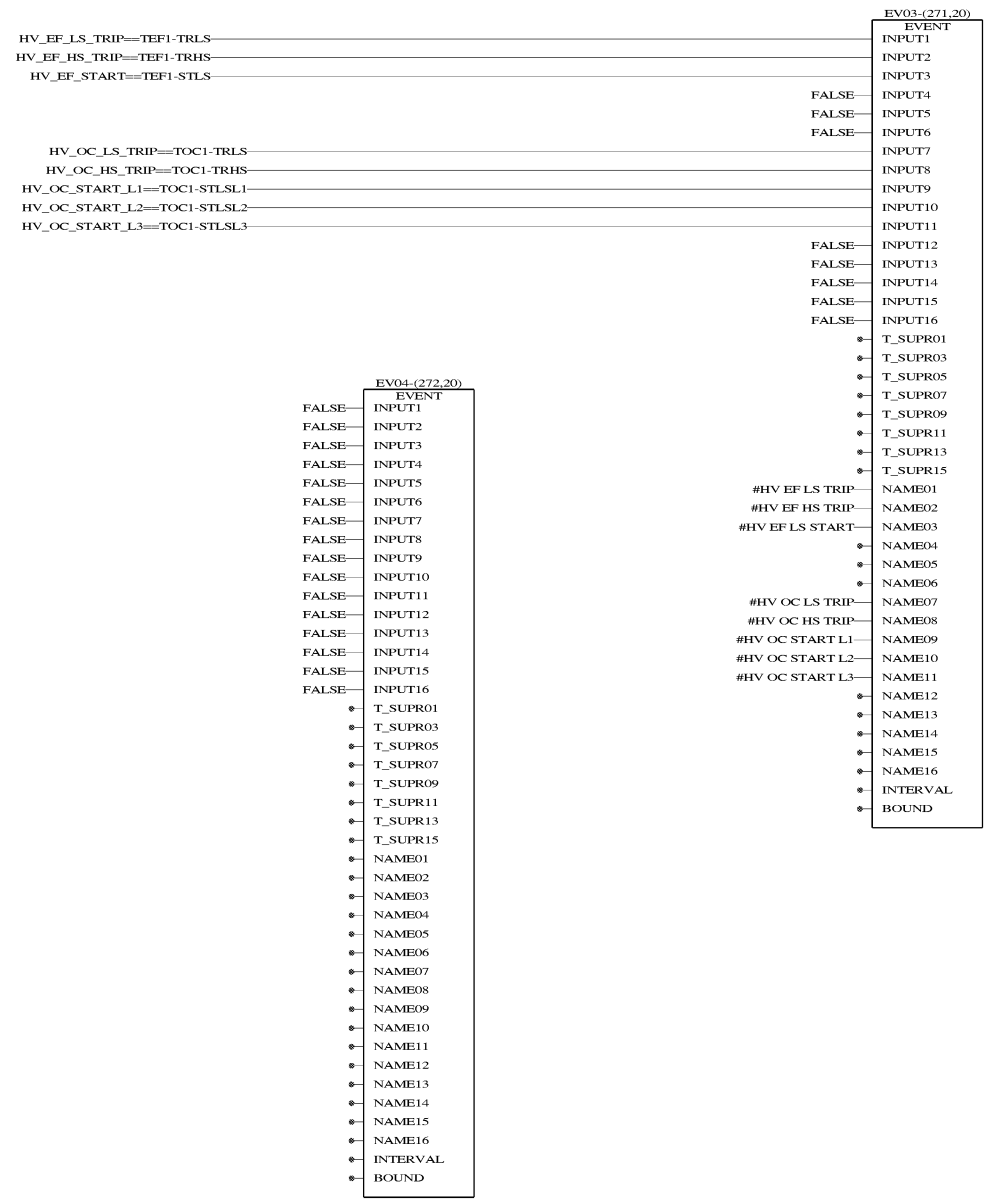


Rev Ind	Reg nr	Prepared	02-04-15	RET521 2p4	Subsidar
Based on	Pcl	Approved Birger Hillström	02-04-20	ABB Autom. Techn. Prod. AB	Resp dep SA/ATA Rev Ind
					Example 2 Sheet 2/2

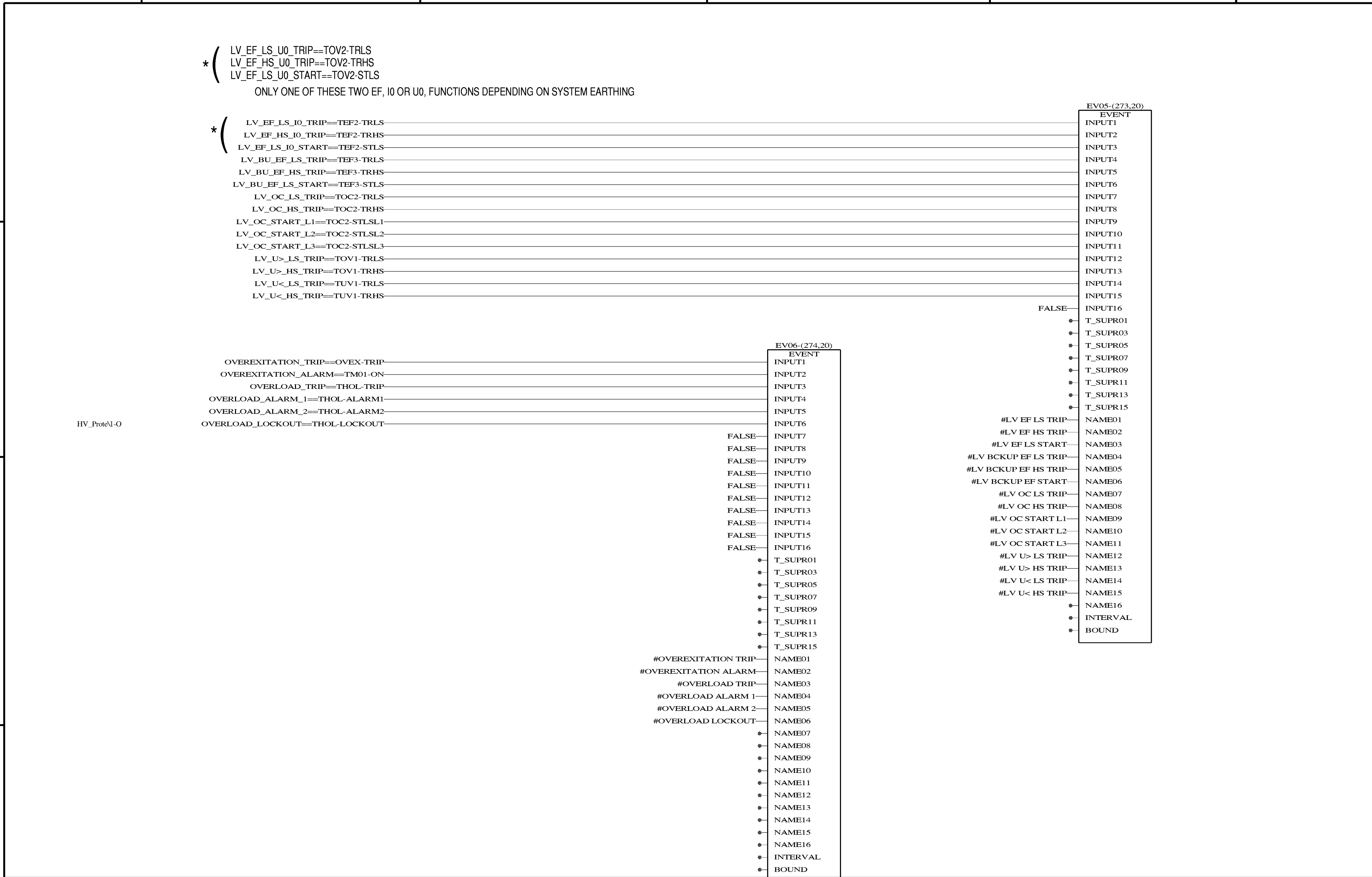
All EVENT blocks in this worksheet are used to report the selected internal binary signals to Substation Control System via LON bus.

If rear LON port is not ordered or it is not connected to SCS then this worksheet has no meaning.

		Prepared	02-04-15	RET521 2p4		Events_v
		Approved Birger Hillström	02-04-20			
					Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 2	Sheet 1/6
Based on	Pcl					

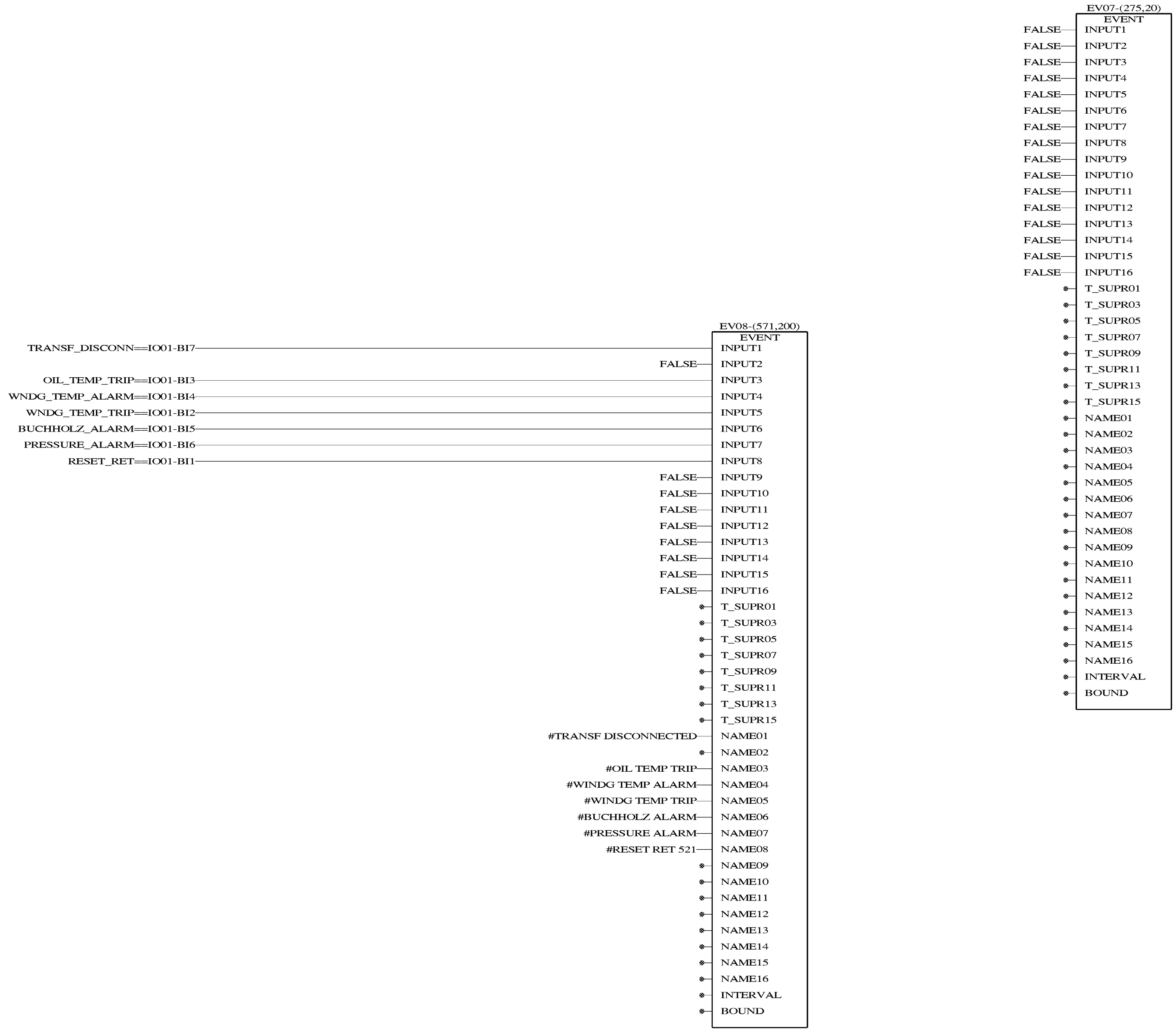


Prepared	02-04-15	RET521 2p4	Events_v
Approved Birger Hillström	02-04-20		Resp dep SA/ATA; Rev Ind
Rev Ind; Reg nr		ABB Autom. Techn. Prod. AB	Example 2; Sheet 2/6
Based on; Pcl			

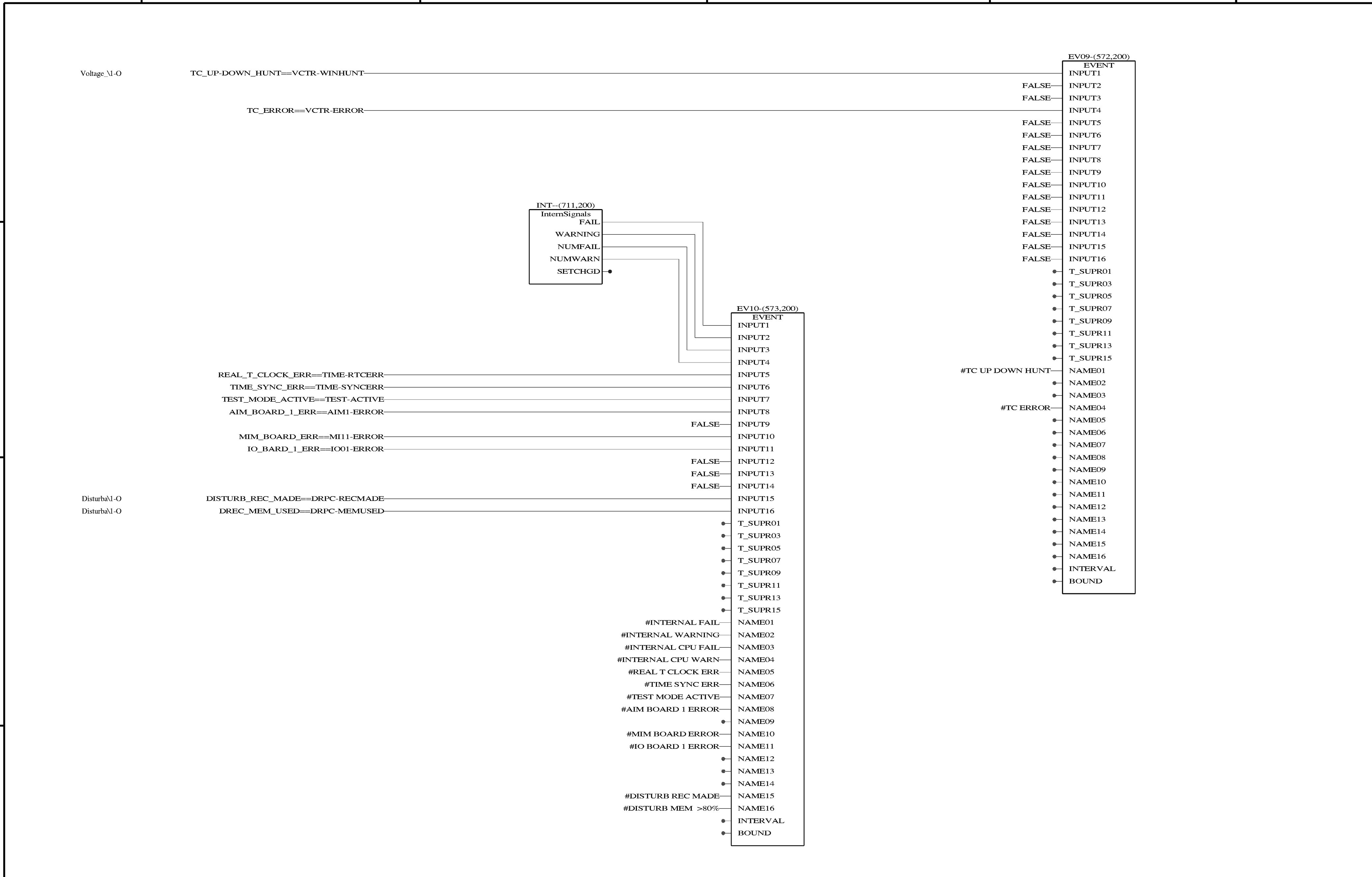


Prepared	02-04-15	RET521 2p4	Events_v
Approved Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr	ABB Autom. Techn. Prod. AB	Example 2	Sheet 3/6
Based on	Pcl			

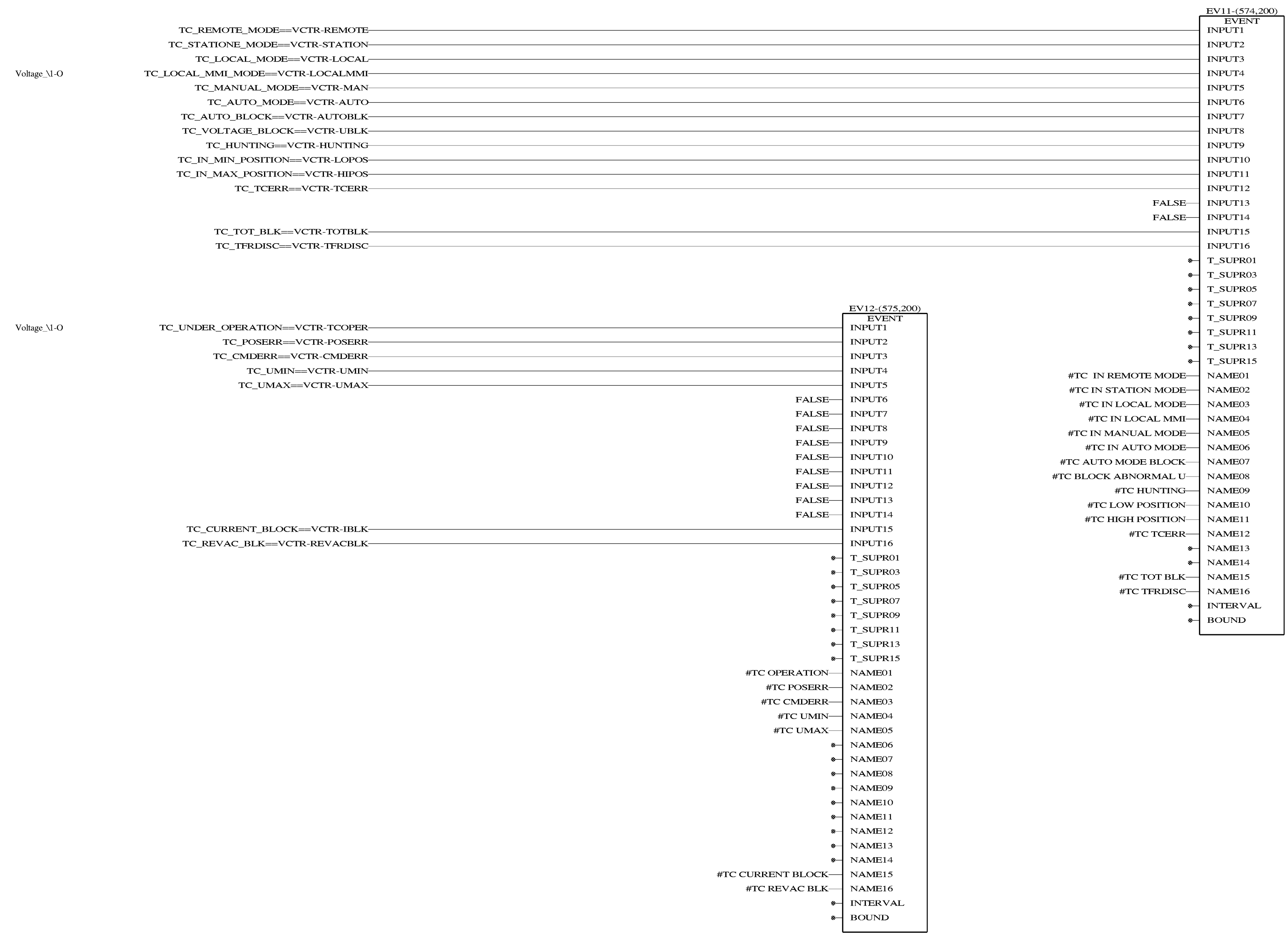
Event block 07 free, preferably used by customer.



Prepared		02-04-15	RET521 2p4		Events_v
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 2	Sheet 4/6
Based on	Pcl				



Prepared	02-04-15	RET521 2p4		Events_v
Approved Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr	ABB Autom. Techn. Prod. AB	Example 2	Sheet 5/6
Based on	Pcl			



Prepared 02-04-15
Approved Birger Hillström 02-04-20
Rev Ind
Reg nr
Based on
Pcl

RET521 2p4

ABB Autom. Techn. Prod. AB

Events_v

Resp dep SA/ATA
Rev Ind

Example 2

Sheet 6/6

Description Example Config no 3 (1MRK 001 536-24)	Work Sheet No
List of Content	Sheet No 01
Short Configuration Description	Sheet No 02
Configuration of Current & Voltage Signals	Sheet No 03
Configuration of Tap Position Measurement	Sheet No 04
Differential Protection Function	Sheet No 05
HV Protection Functions	Sheet No 06
LV Protection Functions	Sheet No 07
Tripping Logic	Sheet No 08 & 09
Voltage Control Function	Sheet No 10
Configuration of Binary Input/Output Module	Sheet No 11 & 12
Configuration of Disturbance Report	Sheet No 13 & 14
Subsidary Configuration	Sheet No 15
Configuration of Event Reporting via LON bus	Sheet No 16 to 21

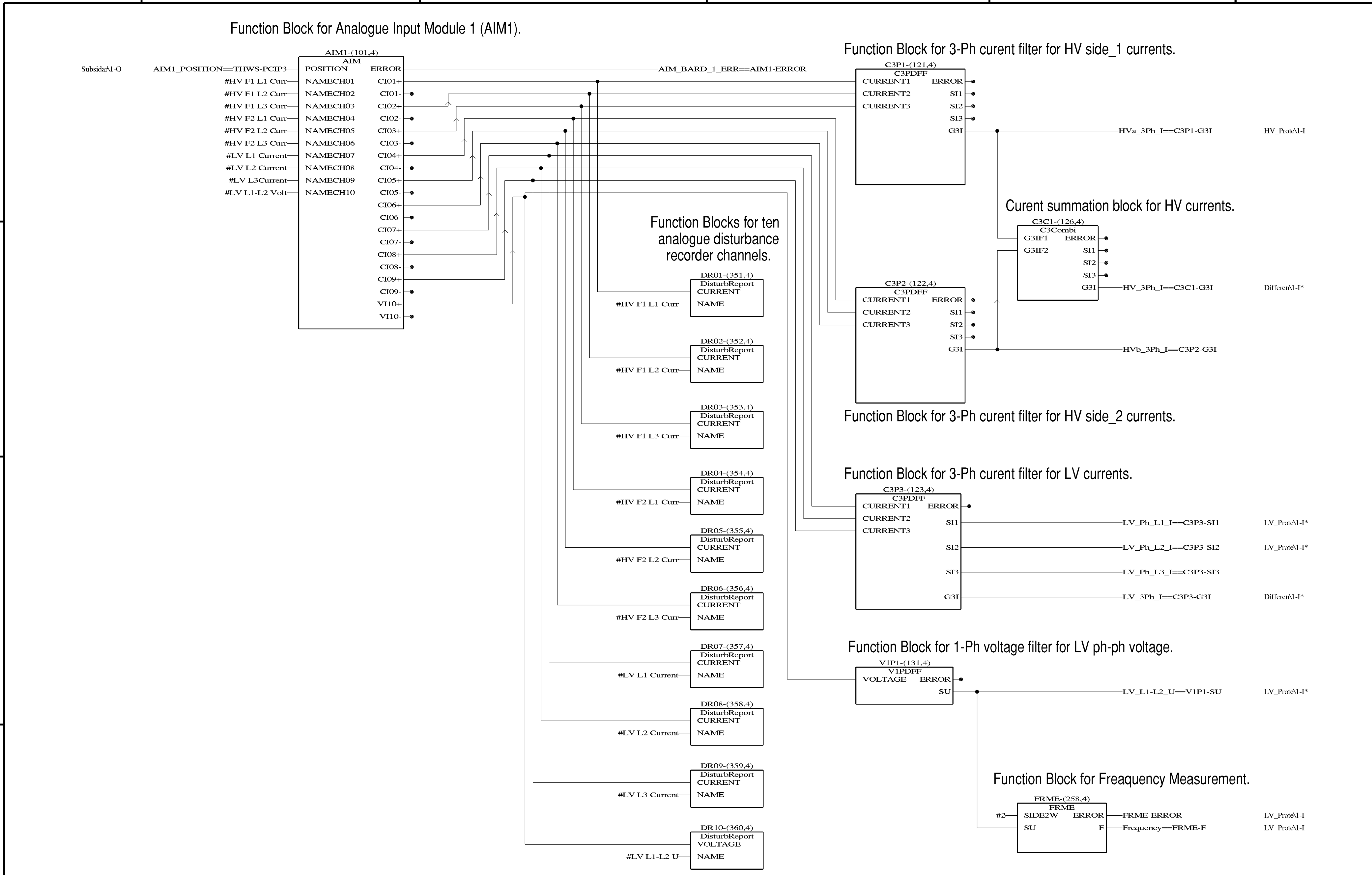
Prepared	02-04-15	RET521 2p4	Overall_
Approved Birger Hillström	02-04-20		Resp dep SA/ATA · Rev Ind
Rev Ind · Reg nr		ABB Automation Products AB	Example 3 · Sheet 1/2
Based on · Pcl			

Short configuration description

The example configuration No 3 is made for protection and control of a two winding power transformer with "T" HV CTs.
In the RET 521 terminal the following hardware modules are included: one AIM (9I+1U), BIM, BOM & MIM.
The tap changer with 17 positions is located on the HV winding. Its position is monitored via 4-20mA analogue signal.
It is assumed that analogue inputs are connected to the following order: HV_IL1_side1, HV_IL2_side1, HV_IL3_side1, HV_IL1_side2, HV_IL2_side2, HV_IL3_side2, LV_IL1, LV_IL2, LV_IL3 & LV_UL1-L2.
The following protection and control function are included in the configuration:
Transformer differential protection (87T & 87H); Side_1 3-Ph HV OC protection (50, 51); Side_1 HV EF protection (50N, 51N);
Transformer 3-Ph HV OC protection (50, 51); Transformer HV EF protection (50N, 51N); Thermal overload protection (49)
LV 3-Ph OC protection (50, 51); LV EF protection (50N, 51N); LV U< protection (27); LV U> protection (59);
Overexcitation protection (24) and LV side voltage control (90).
Individual tripping logic for all CBs are provided.

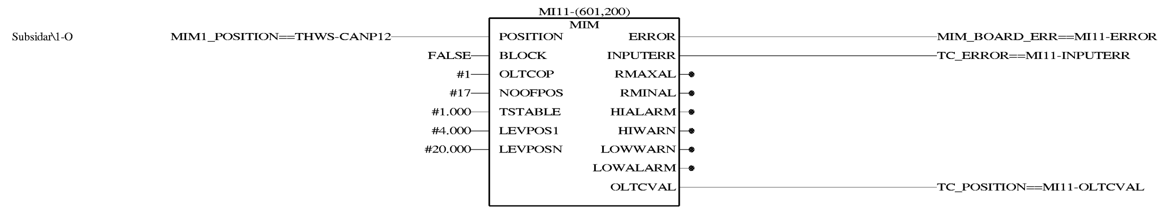
All 10 analogue input signals are connected to the disturbance recorder. In addition to that 48 binary signals are connected to the disturbance recorder as well.

Finally binary events to the substation control system which will be automatically reported via LON bus are configured.



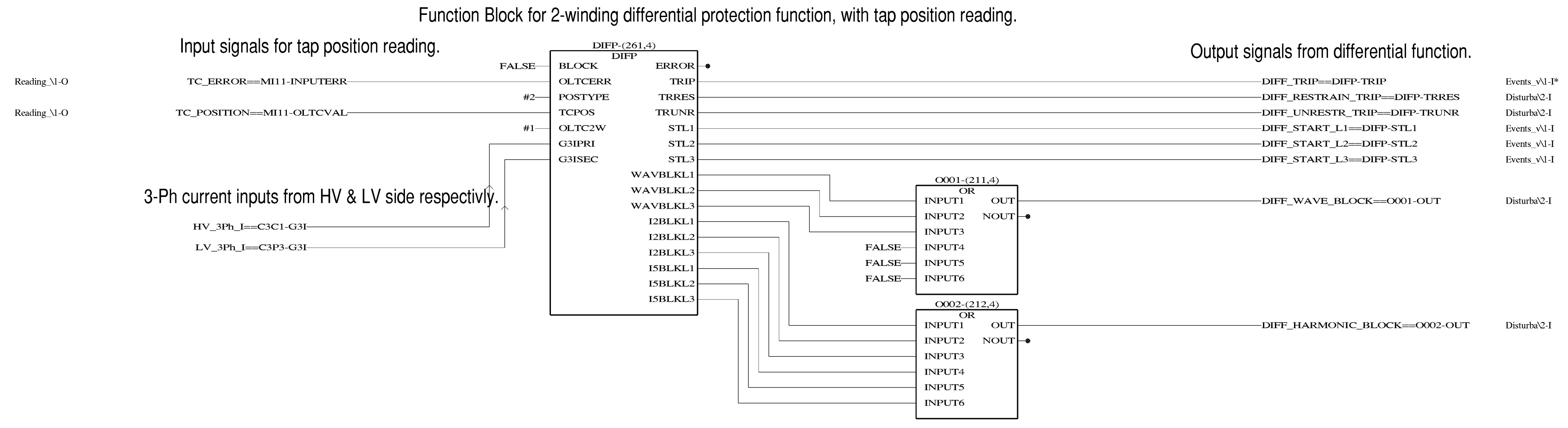
Prepared		02-04-15	RET521 2p4	Analogue
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA Rev Ind
Rev Ind	Reg nr		ABB Automation Products AB	Example 3 Sheet 1/1
Based on	Pcl			

Function Block for mA Input Module (MIM), input channel 1.

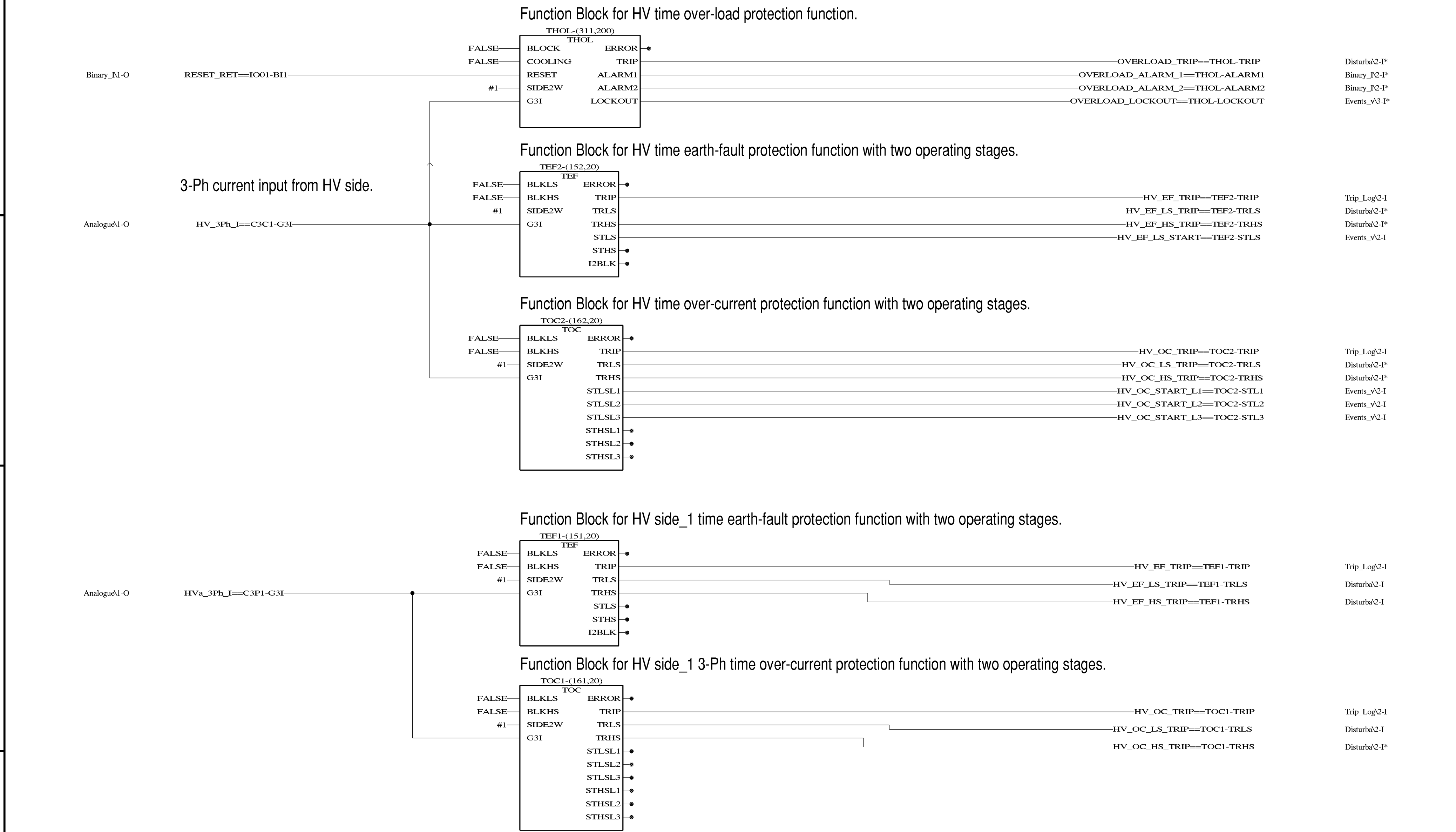


This function block is used here to convert 4-20mA input signal into 17 tap positions.
Value of tap position is then given to differential protection function and
voltage control function in order to enhance their functionality.

		Prepared	02-04-15	RET521 2p4		Reading_
		Approved Birger Hillström	02-04-20			
					Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr			ABB Automation Products AB	Example 3	Sheet 1/1
Based on	Pcl					

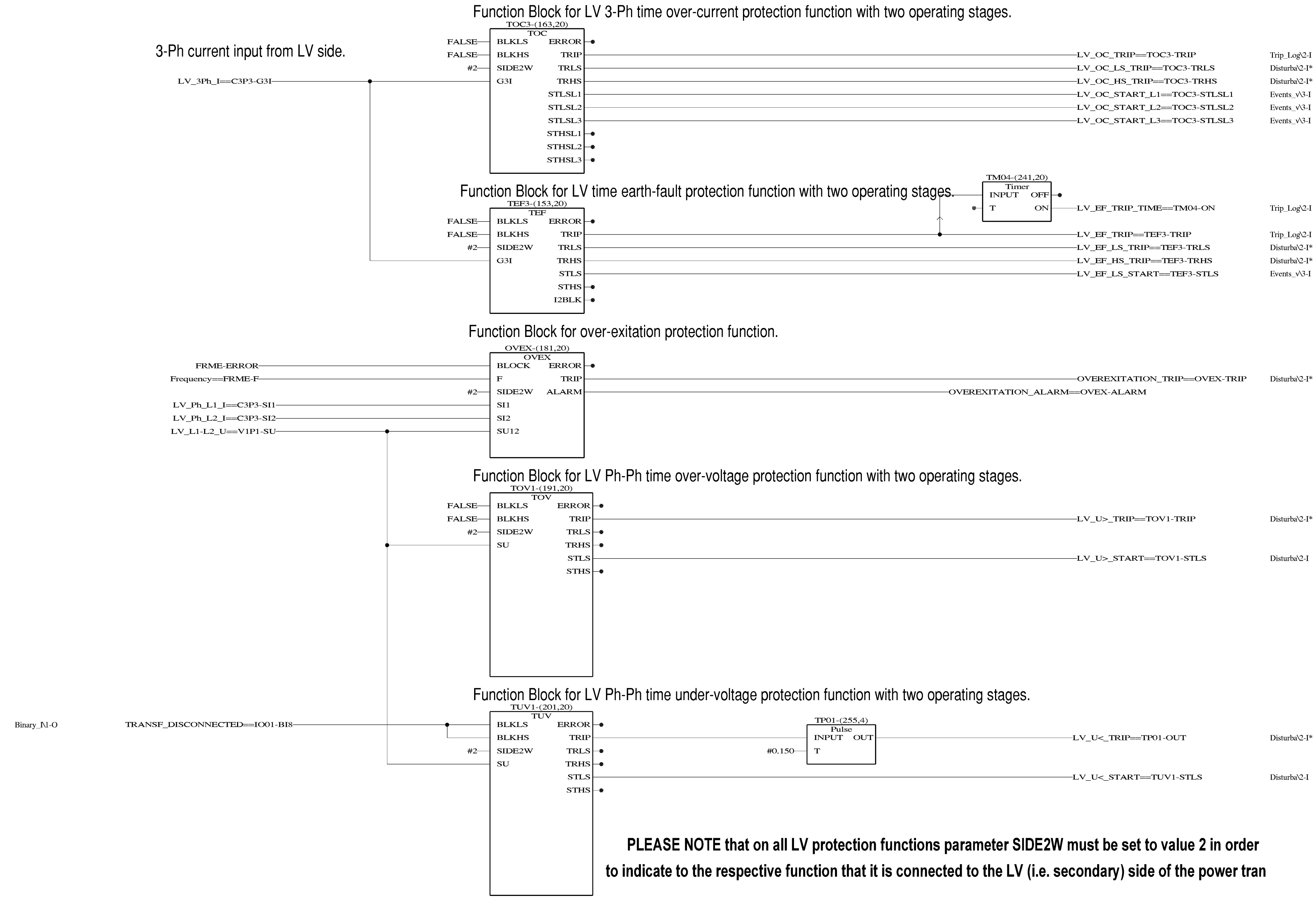


		Prepared	02-04-15	RET521 2p4	Differen
		Approved Birger Hillström	02-04-20		
					Resp dep SA/ATA Rev Ind
Rev Ind	Reg nr			ABB Automation Products AB	Example 3 Sheet 1/1
Based on	Pcl				



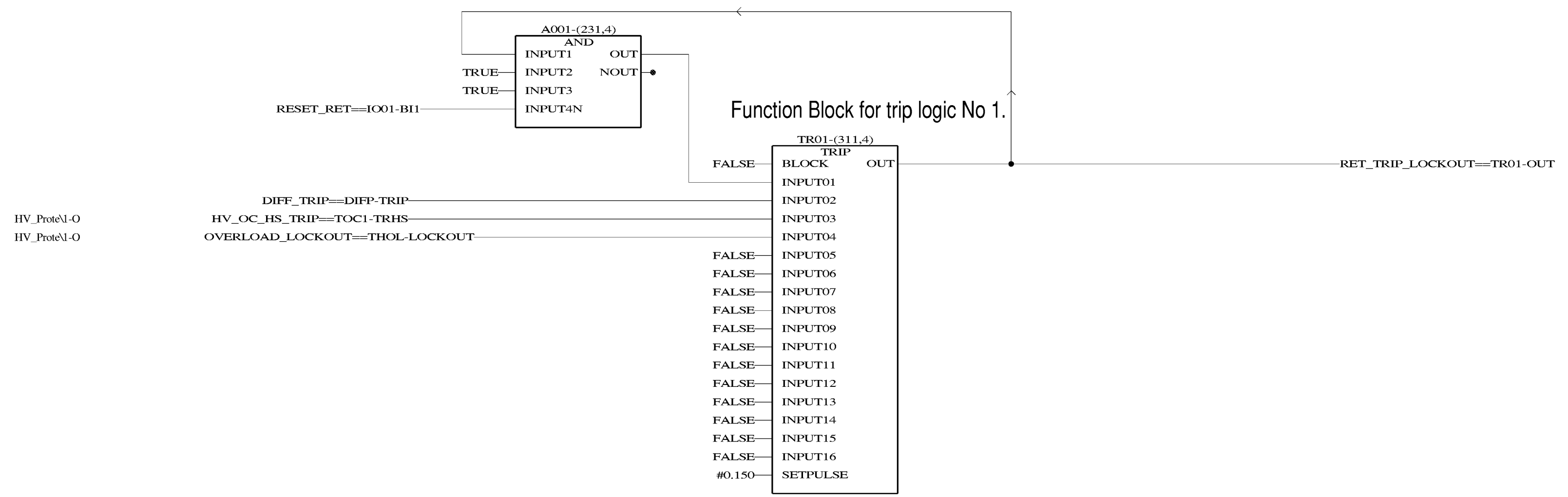
PLEASE NOTE that on all HV protection functions parameter SIDE2W must be set to value 1 in order to indicate to the respective function that it is connected to the HV (i.e. primary) side of the power transformer.

Prepared		02-04-15	RET521 2p4
Approved	Birger Hillström	02-04-20	
Rev Ind	Reg nr	Resp dep SA/ATA	Rev Ind
Based on	Pcl	ABB Automation Products AB	Example 3
HV_Prote	Sheet 1/1		



PLEASE NOTE that on all LV protection functions parameter SIDE2W must be set to value 2 in order to indicate to the respective function that it is connected to the LV (i.e. secondary) side of the power tran

Prepared		02-04-15	RET521 2p4	LV_Prote
Approved	Birger Hillström	02-04-20		
Rev Ind	Reg nr		Resp dep SA/ATA	Rev Ind
Based on	Pcl		ABB Automation Products AB	Example 3	Sheet 1/1



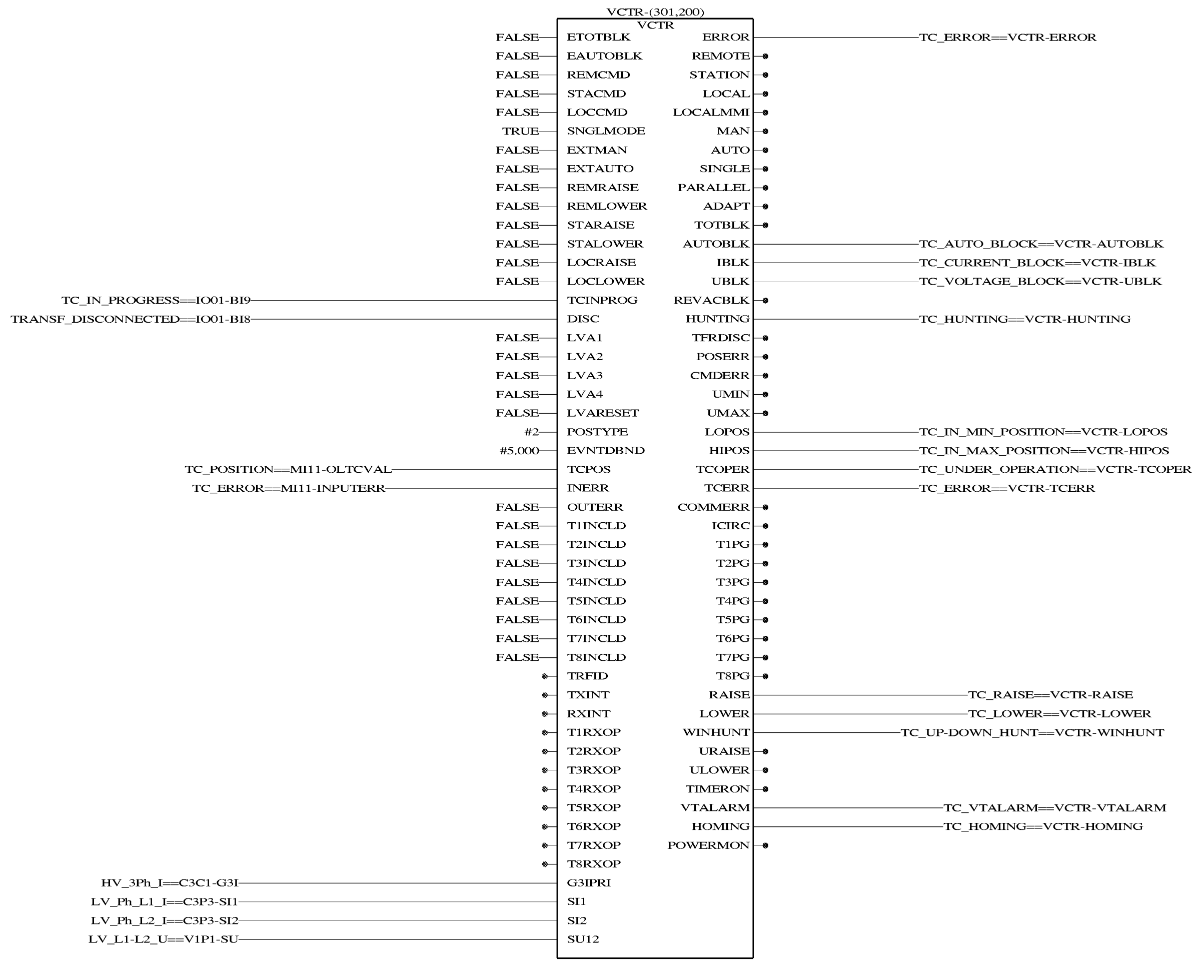
This function block is used together with one AND gate in order to get trip lockout after differential function or HV high-set over-current function operation.

Prepared		02-04-15	RET521 2p4
Approved	Birger Hillström	02-04-20	
Rev Ind		Reg nr	Resp dep SA/ATA	Rev Ind
Based on		Pcl	ABB Automation Products AB	Example 3

Trip_Log

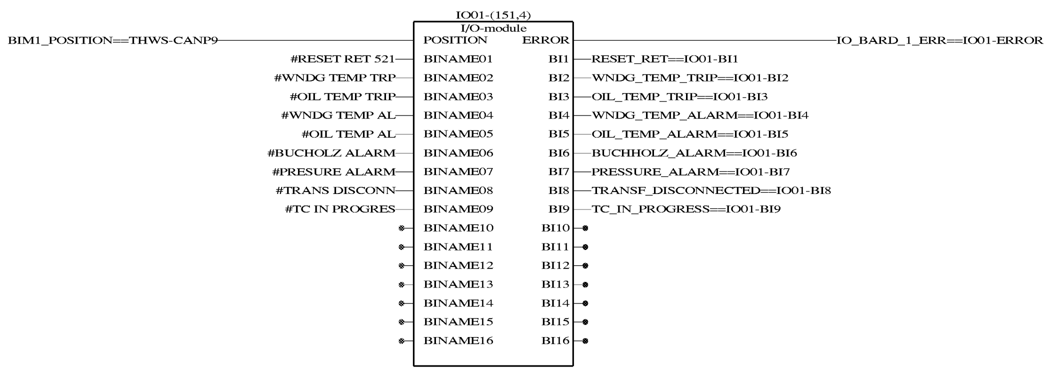
Sheet 1/2

Function Block for LV side voltage control function (i.e. tap changer control function).
VCTR parallel for maximum 8 parallel operating transformers.



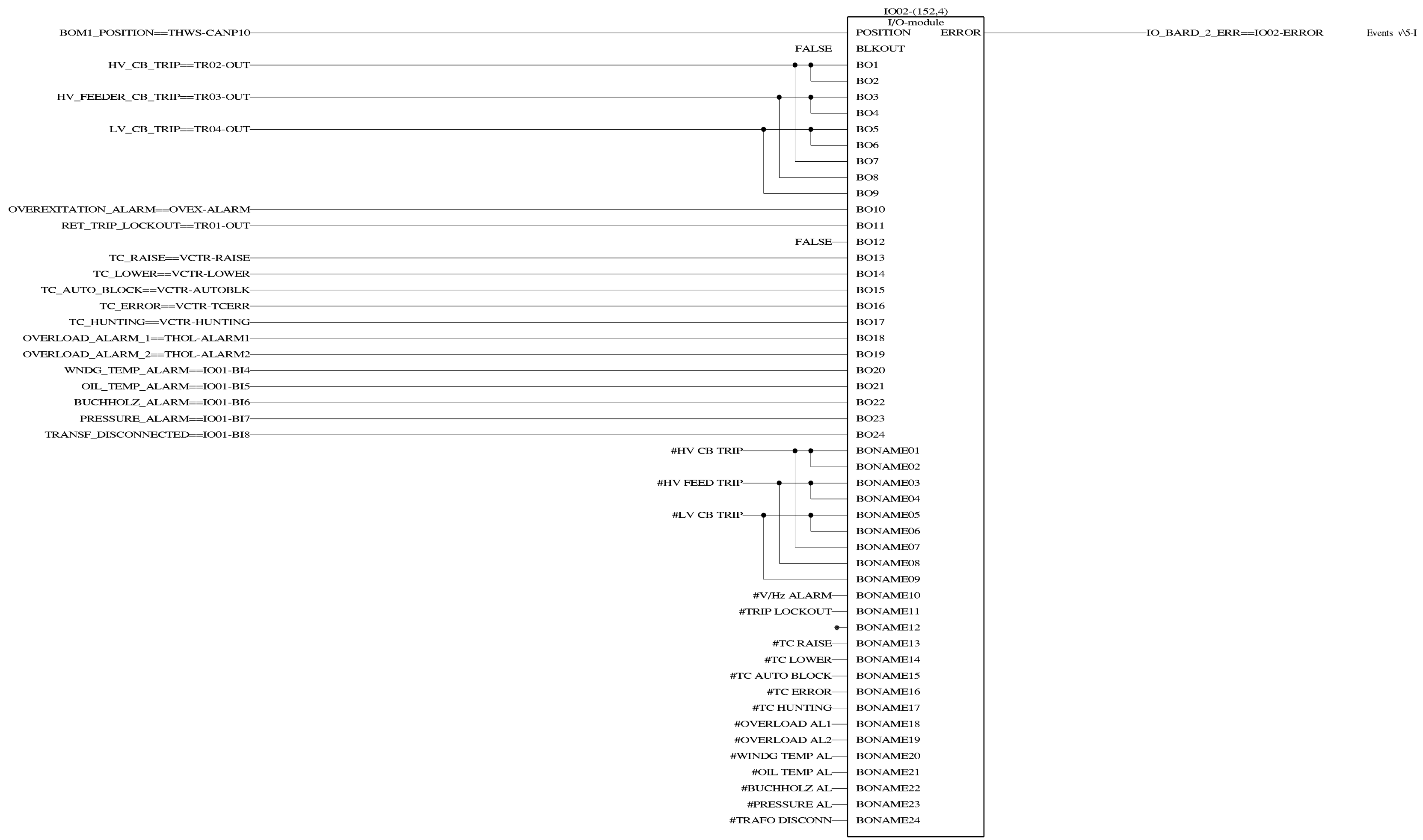
Prepared		02-04-15	RET521 2p4		Voltage_
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr		ABB Automation Products AB	Example 3	Sheet 1/1
Based on	Pcl				

Function Block for Binary Input Module (BIM) with 16 optocoupler inputs.



		Prepared	02-04-15	RET521 2p4	Binary_I
		Approved Birger Hillström	02-04-20		
					Resp dep SA/ATA Rev Ind
Rev Ind		Reg nr		ABB Automation Products AB	Example 3 Sheet 1/2
Based on		Pcl			

Function Block for Binary Output Module (BOM) with 24 contact outputs.



Prepared 02-04-15
Approved Birger Hillström 02-04-20

Rev Ind | Reg nr
Based on | Pcl

RET521 2p4

ABB Automation Products AB

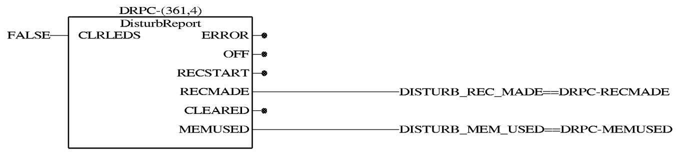
Resp dep SA/ATA | Rev Ind

Example 3

Binary_I

Sheet 2/2

Function Block for Disturbance Report function.
It provides binary indication when new recording is made and when avaiable memory is used.

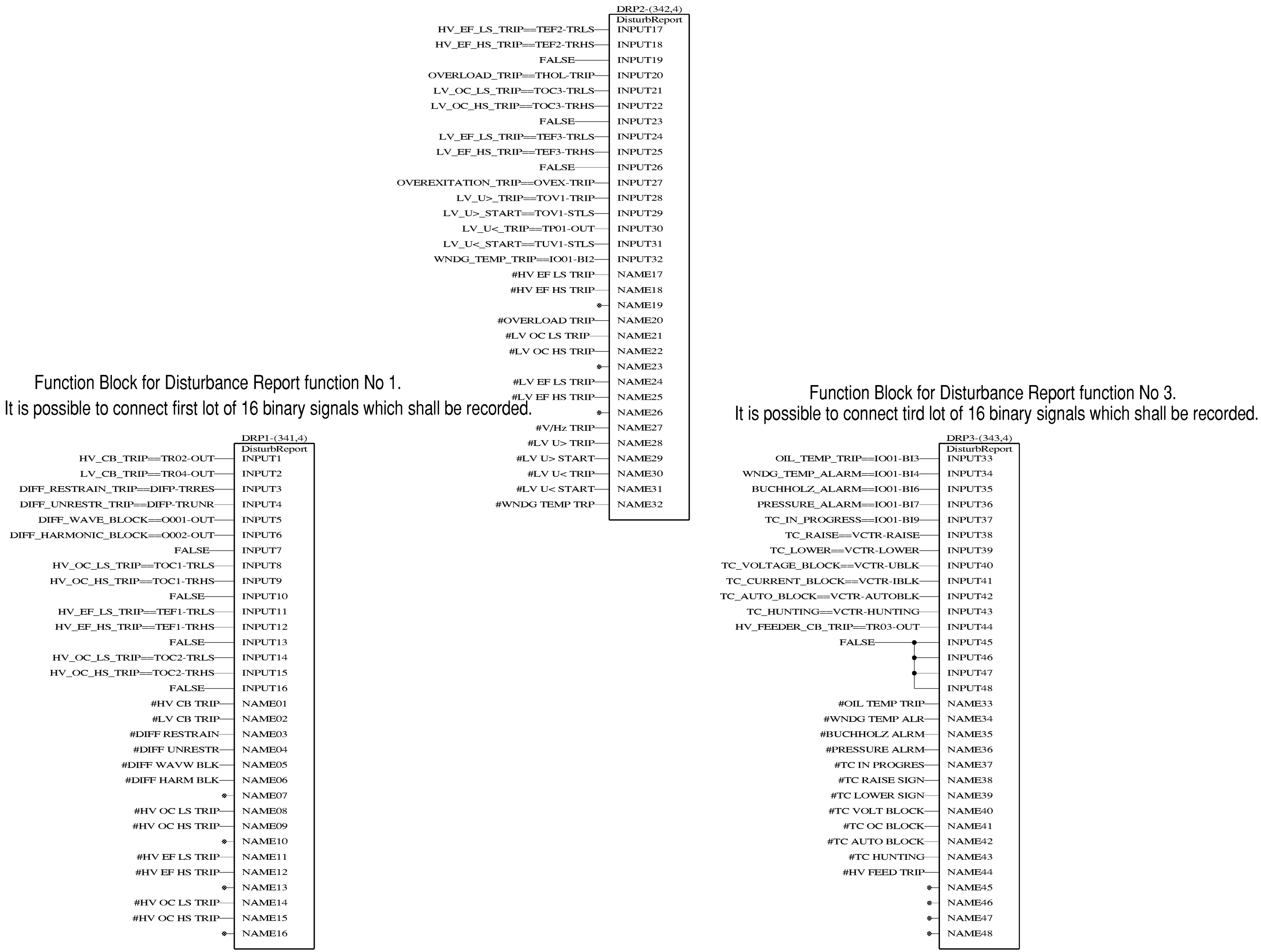


Prepared		02-04-15	RET521 2p4	Disturba
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr		ABB Automation Products AB	Example 3	Sheet 1/2
Based on	Pcl				

Function Block for Disturbance Report function No 2.
It is possible to connect second lot of 16 binary signals which shall be recorded.

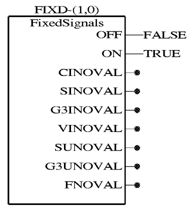
Function Block for Disturbance Report function No 1.
It is possible to connect first lot of 16 binary signals which shall be recorded.

Function Block for Disturbance Report function No 3.
It is possible to connect tird lot of 16 binary signals which shall be recorded.

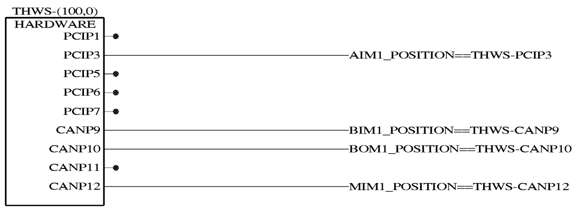


Prepared	02-04-15	RET521 2p4		Disturba
Approved Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr	ABB Automation Products AB	Example 3	Sheet 2/2
Based on	Pcl			

Function Block for fixed signals.
It defines binary zero (i.e. FALSE) and binary one (i.e. TRUE) values.

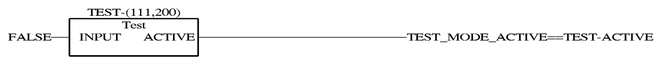


Function Block for terminal hardware structure.
It defines internal positions of all ordered hardware modules.
(i.e. AIM1, BIM1, BOM1 & MIM in this configuration)



Function Block for synchronization of terminal internal real time clock.

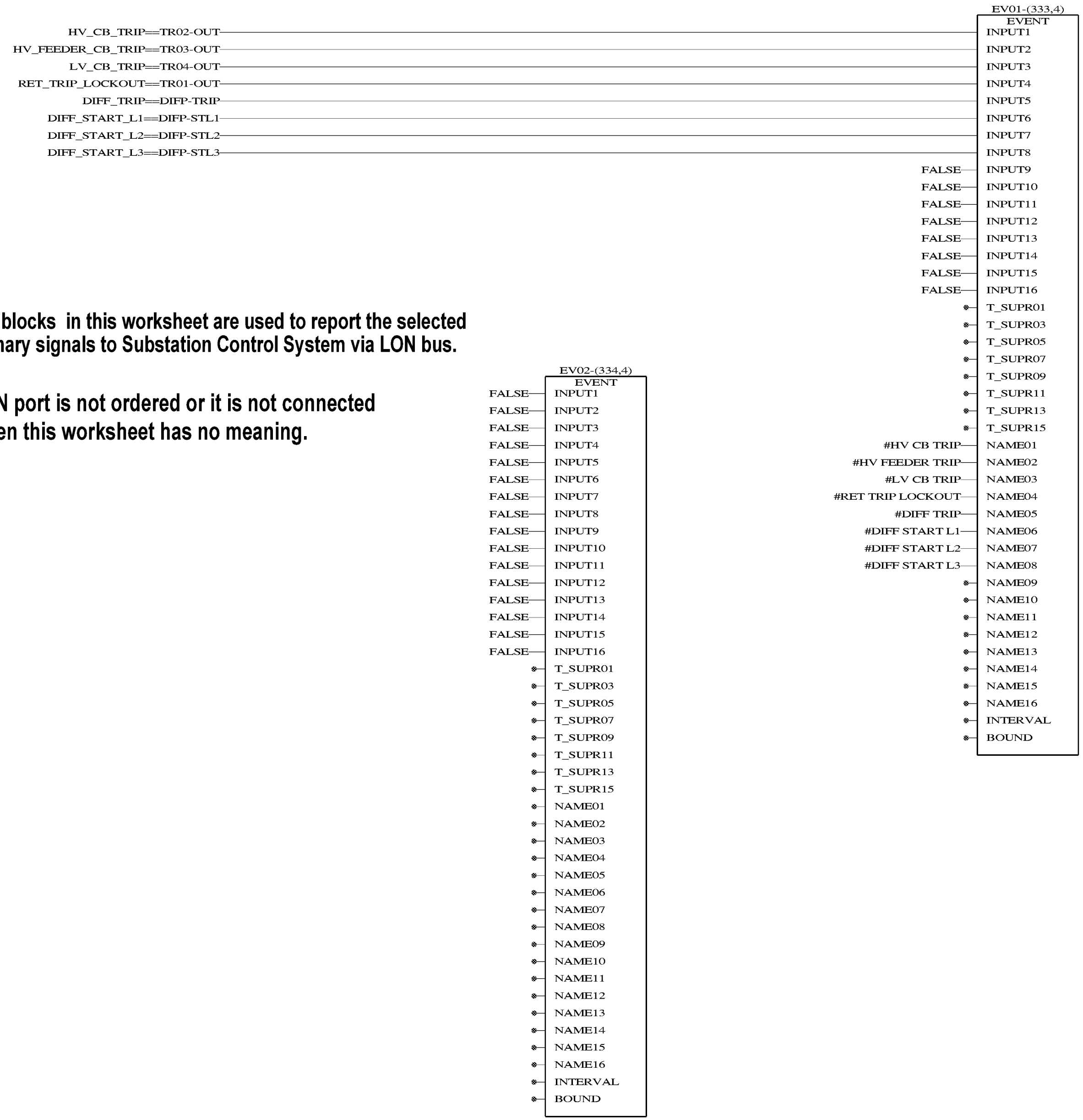
Function Block for terminal "Test Mode"



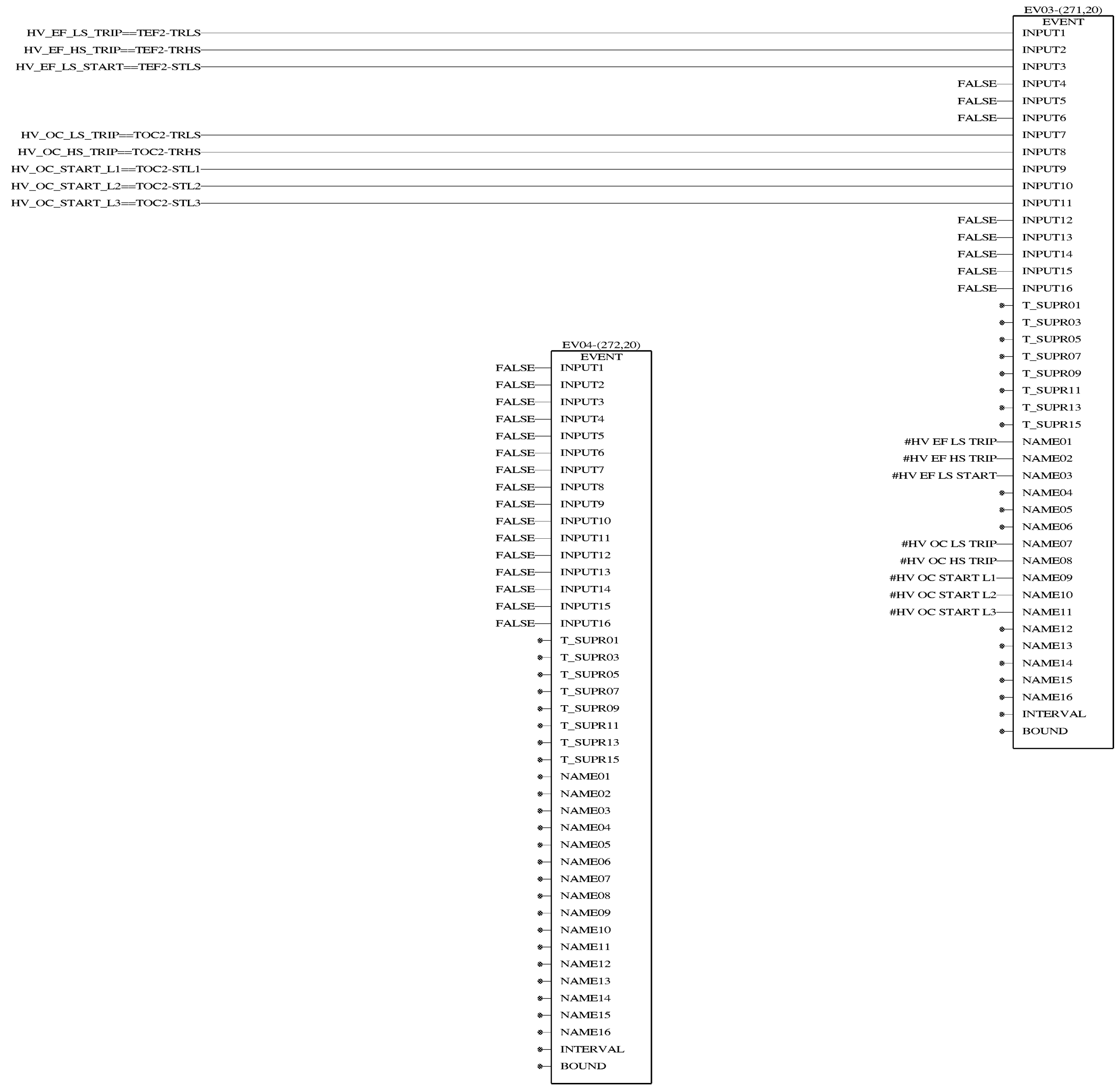
Prepared		02-04-15	RET521 2p4
Approved	Birger Hillström	02-04-20	
Rev Ind	Reg nr	Resp dep SA/ATA	Rev Ind
Based on	Pcl	ABB Automation Products AB	Example 3
Subsidar		Sheet 1/1	

All EVENT blocks in this worksheet are used to report the selected internal binary signals to Substation Control System via LON bus.

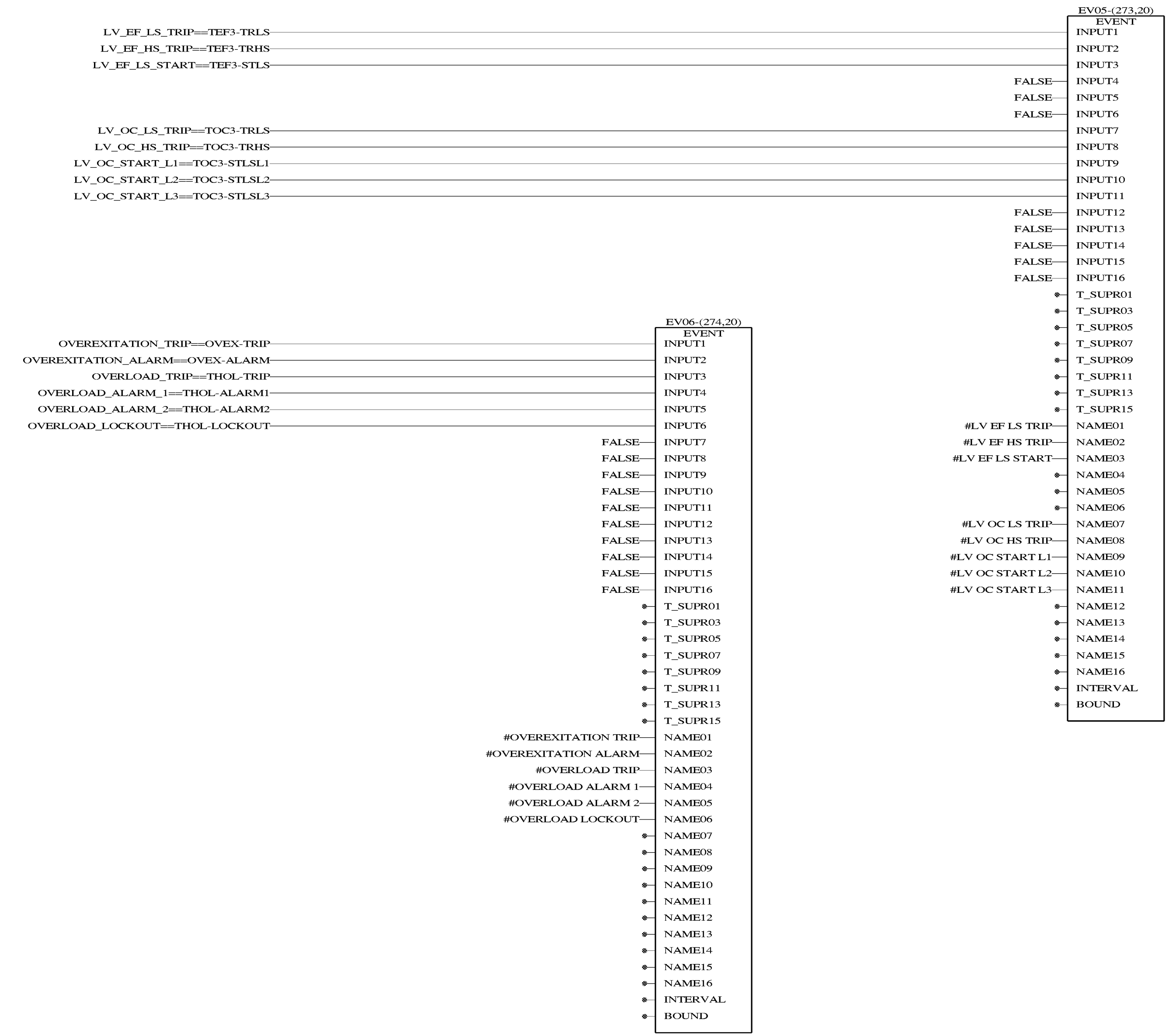
If rear LON port is not ordered or it is not connected to SCS then this worksheet has no meaning.



Rev Ind	Reg nr	Prepared	02-04-15	RET521 2p4	Events_v
Based on	Pcl	Approved Birger Hillström	02-04-20	ABB Automation Products AB	Resp dep SA/ATA
					Rev Ind
					Example 3
					Sheet 1/6

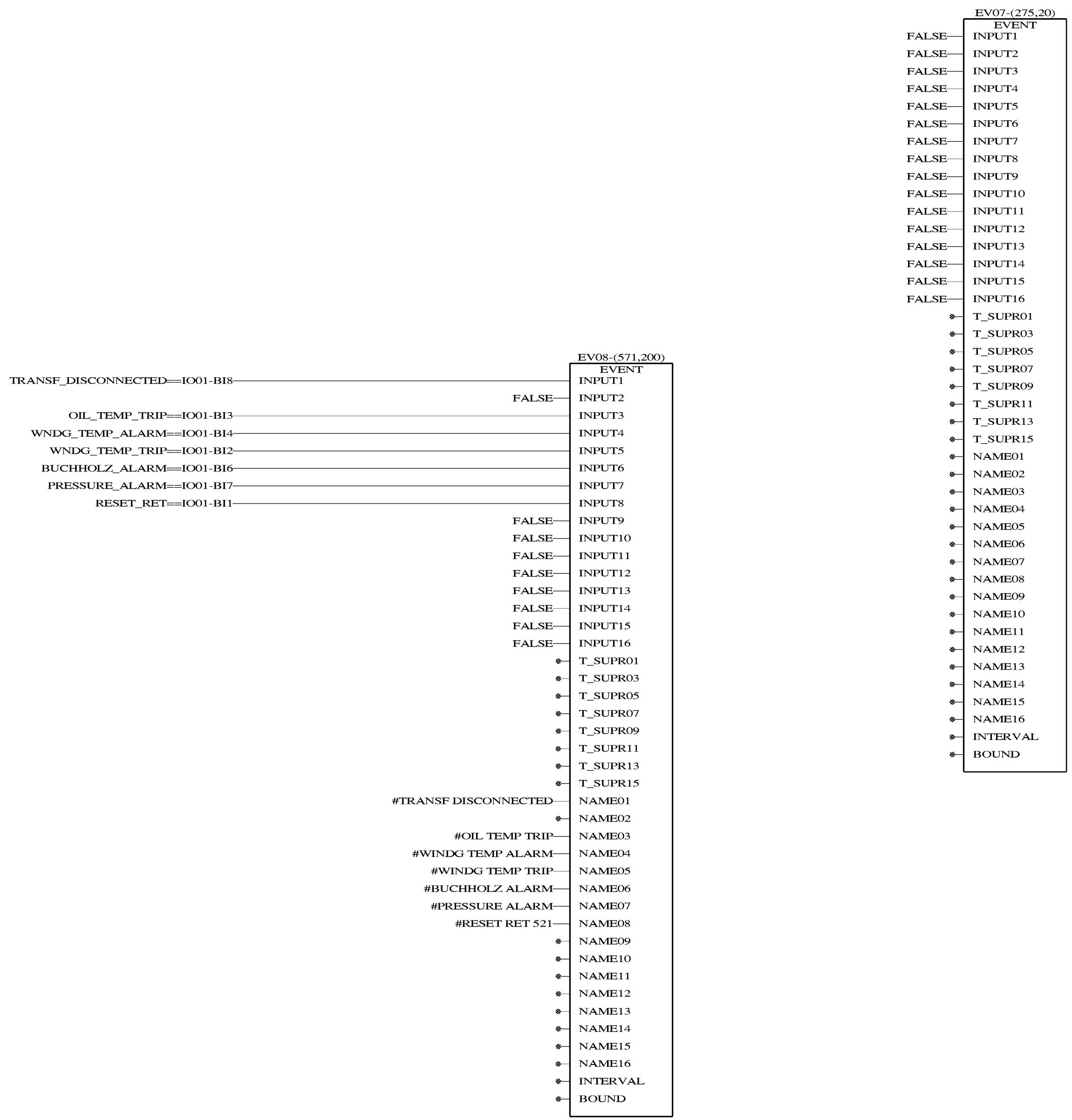


Prepared	02-04-15	RET521 2p4	Events_v
Approved Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr	ABB Automation Products AB	Example 3	Sheet 2/6
Based on	Pcl			

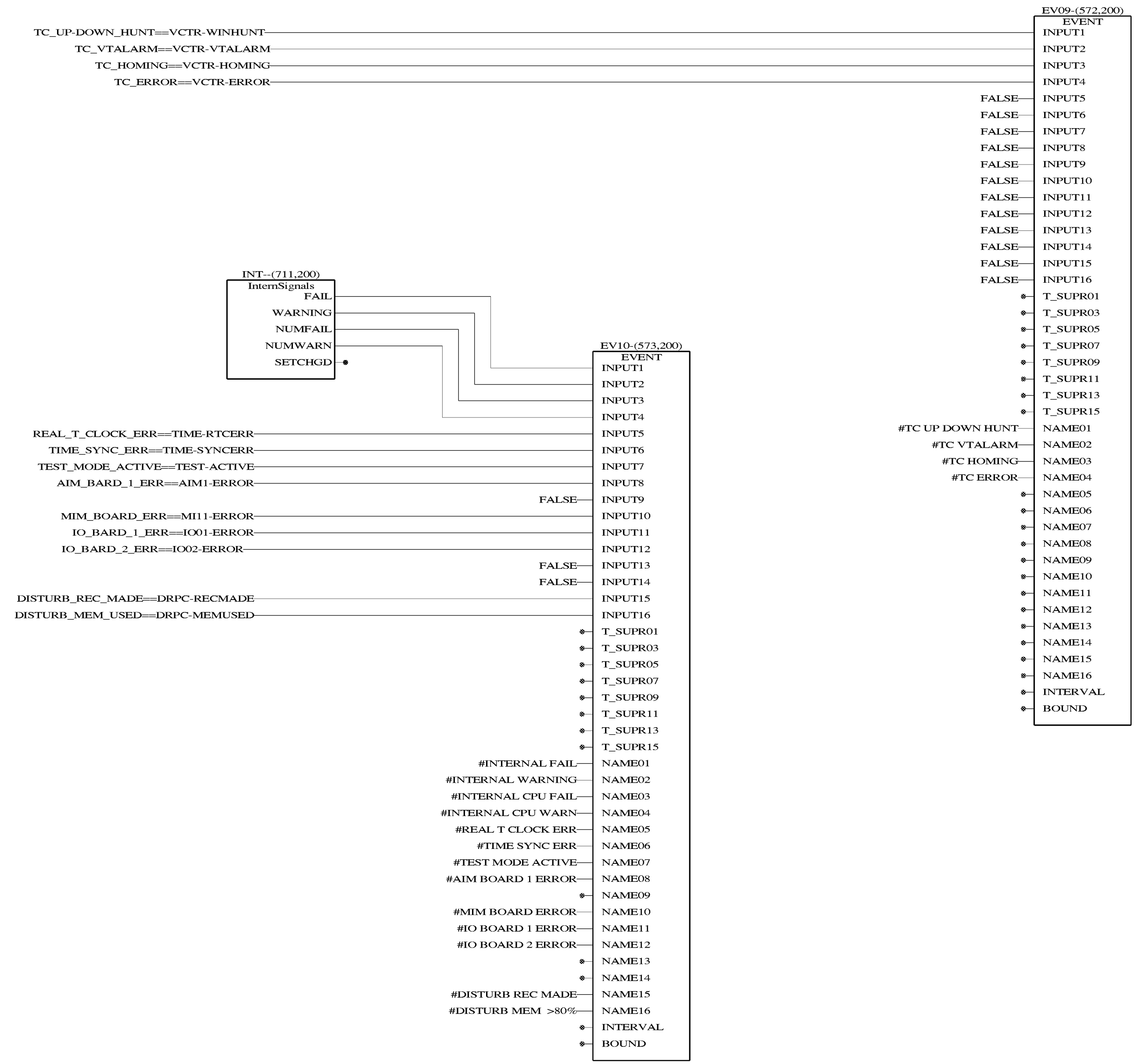


Rev Ind	Reg nr	Prepared 02-04-15	RET521 2p4	Events_v
Based on	Pcl	Approved Birger Hillström 02-04-20	ABB Automation Products AB	Resp dep SA/ATA, Rev Ind
				Example 3, Sheet 3/6

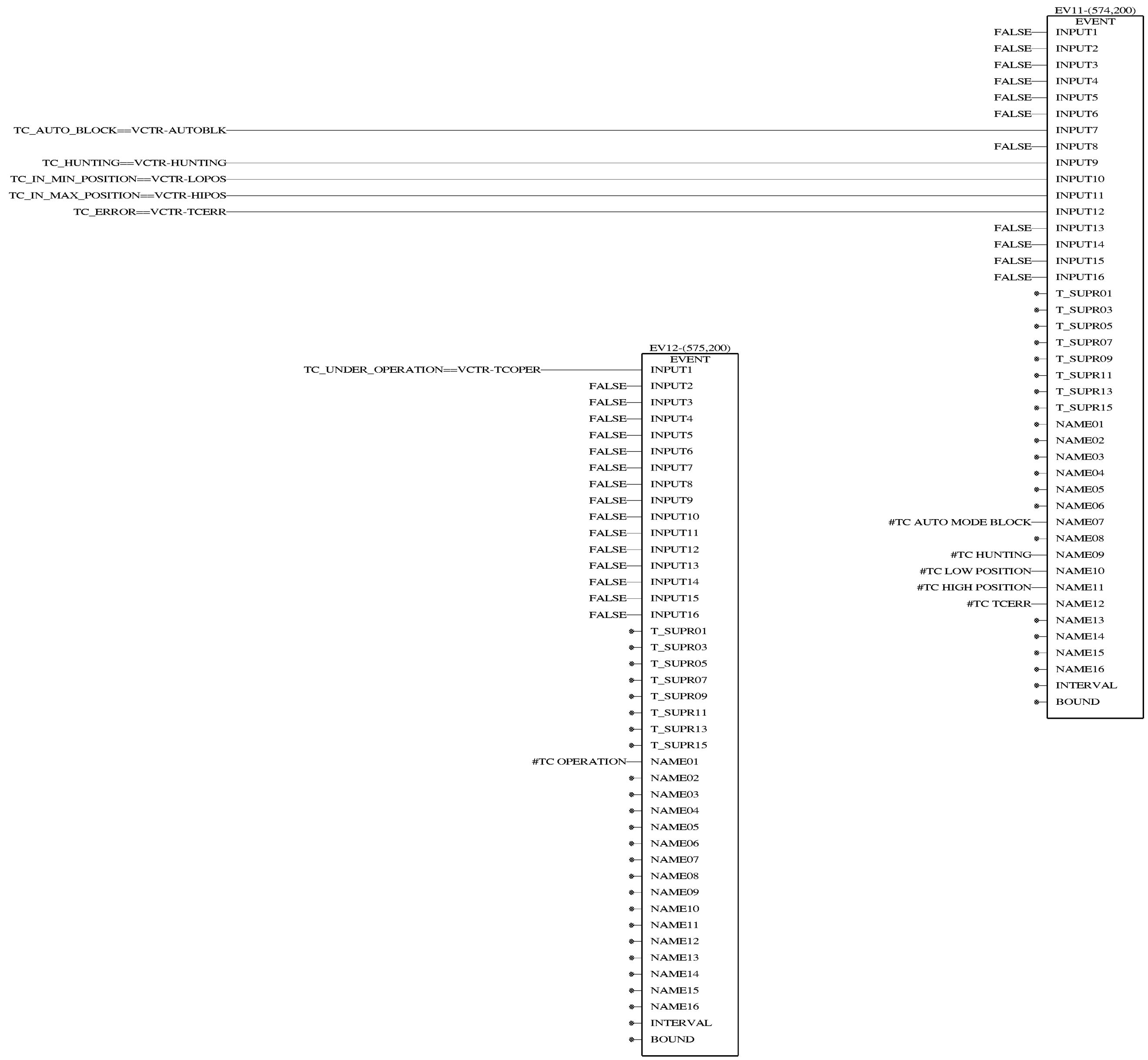
Event block 07 free, preferably used by customer.



Prepared		02-04-15	RET521 2p4
Approved	Birger Hillström	02-04-20	
Rev Ind	Reg nr	Resp dep SA/ATA	Rev Ind
Based on	Pcl	ABB Automation Products AB	Example 3
Events_v			Sheet 4/6



Prepared	02-04-15	RET521 2p4	Events_v
Approved Birger Hillström	02-04-20		
Rev Ind	Reg nr	ABB Automation Products AB	Resp dep SA/ATA, Rev Ind
Based on	Pcl		Example 3, Sheet 5/6



Prepared		02-04-15	RET521 2p4		Events_v
Approved	Birger Hillström	02-04-20			
Rev Ind	Reg nr			Resp dep SA/ATA	Rev Ind
Based on	Pcl		ABB Automation Products AB	Example 3	Sheet 6/6

Description Example Config no 4 (1MRK 001 536-25)	Work Sheet No
List of Content	Sheet No 01
Short Configuration Description	Sheet No 02
Configuration of Current & Voltage Signals	Sheet No 03 & 04
Reading of Tap Position	Sheet No 05
Differential Protection Function	Sheet No 06
HV Protection Functions	Sheet No 07
MV Protection Functions	Sheet No 08
LV Protection Functions	Sheet No 09
Tripping Logic	Sheet No 10
Voltage Control Function	Sheet No 11
Configuration of Binary Input Module	Sheet No 12
Configuration of Binary Output Module	Sheet No 13
Configuration of Disturbance Report	Sheet No 14 & 15
Subsidary Configuration	Sheet No 16
Configuration of Event Reporting via LON bus	Sheet No 17 to 22

Prepared		02-04-20	RET521 2p4	Overall_
Approved	Birger Hillström	02-04-25		Resp dep SA/ATA / Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 4 / Sheet 1/2
Based on	Pcl			

Short configuration description

The example configuration No 4 is made for protection and control of a three winding power transformer with "T" HV CTs.

In the RET 521 terminal the following hardware modules are included: AIM1 (7I+3U), AIM2 (7I+3U), BIM & BOM.

It is assumed that analogue inputs are connected to the following order to AIM1 module: HV_IL1_side1, HV_IL2_side1, HV_IL3_side1, HV_IL1_side2, HV_IL2_side2, HV_IL3_side2, HV Neutral Current, HV_UL1-L2, HV_Uopen_delta & LV_Uopen_delta. To the AIM2 the following analogue inputs are connected: MV_IL1, MV_IL2, MV_IL3, LV_IL1, LV_IL2, LV_IL3, MV Neutral Current, MV_UL1, MV-UL2 & MV_UL3.

The following protection and control function are included in the configuration:

Transformer differential protection (87T & 87H); HV restricted earth fault protection (87N); MV restricted earth fault protection (87N); Transformer 3-Ph HV OC protection (50, 51); Transformer HV directional EF protection (67N); Thermal overload protection (49); HV U< protection (27); HV U> protection (59); MV 3-Ph U< protection (27); MV 3-Ph U> protection (59);

Transformer 3-Ph MV directional OC protection (67); Transformer MV directional EF protection (67N); Overexcitation protection (24); LV 3-Ph OC protection (50, 51); LV EF protection (50N, 51N) and MV side voltage control (90).

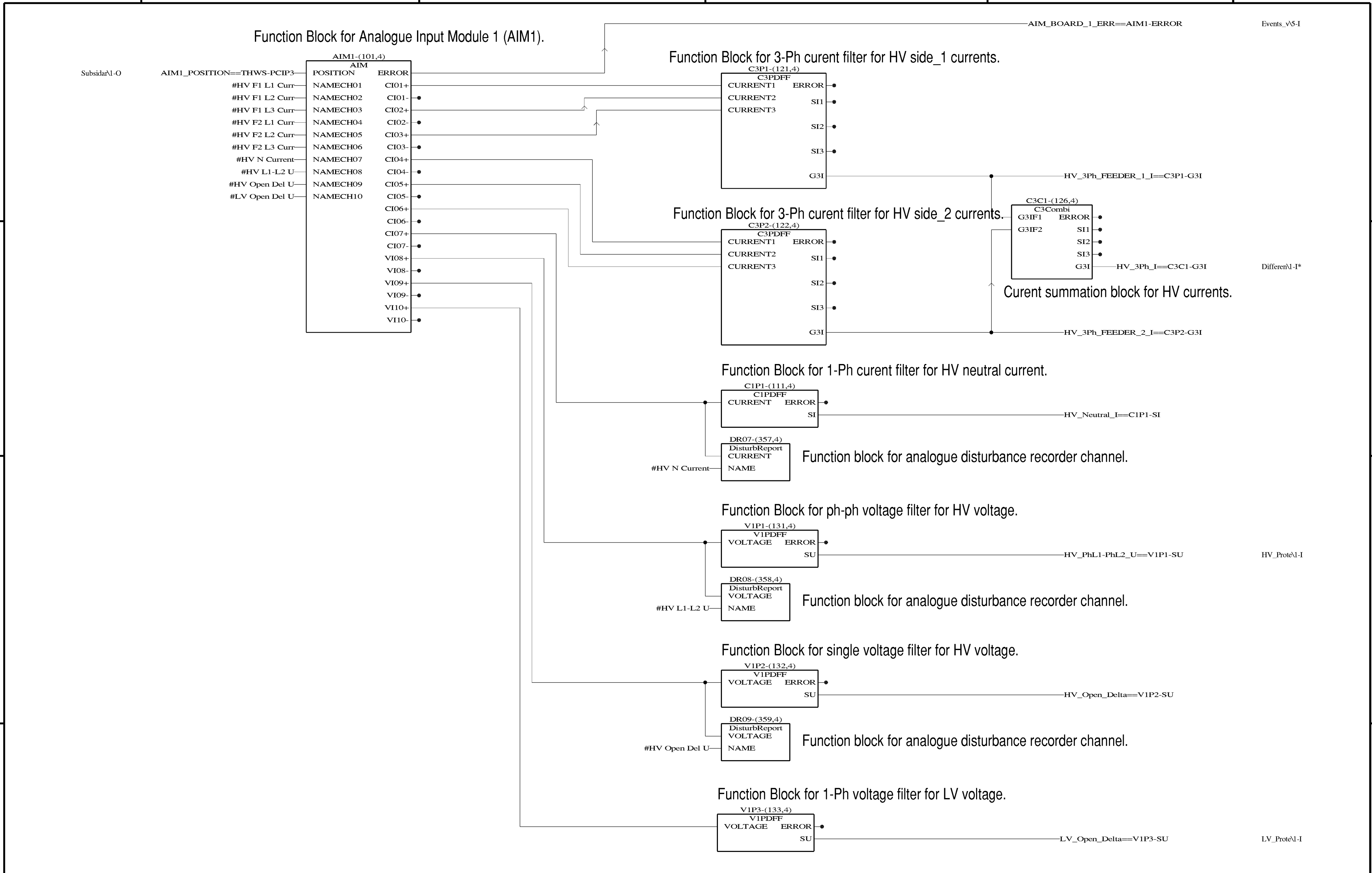
Individual tripping logic for all CBs are provided.

The tap changer position is monitored via six binary inputs (input pattern = binary coded number).

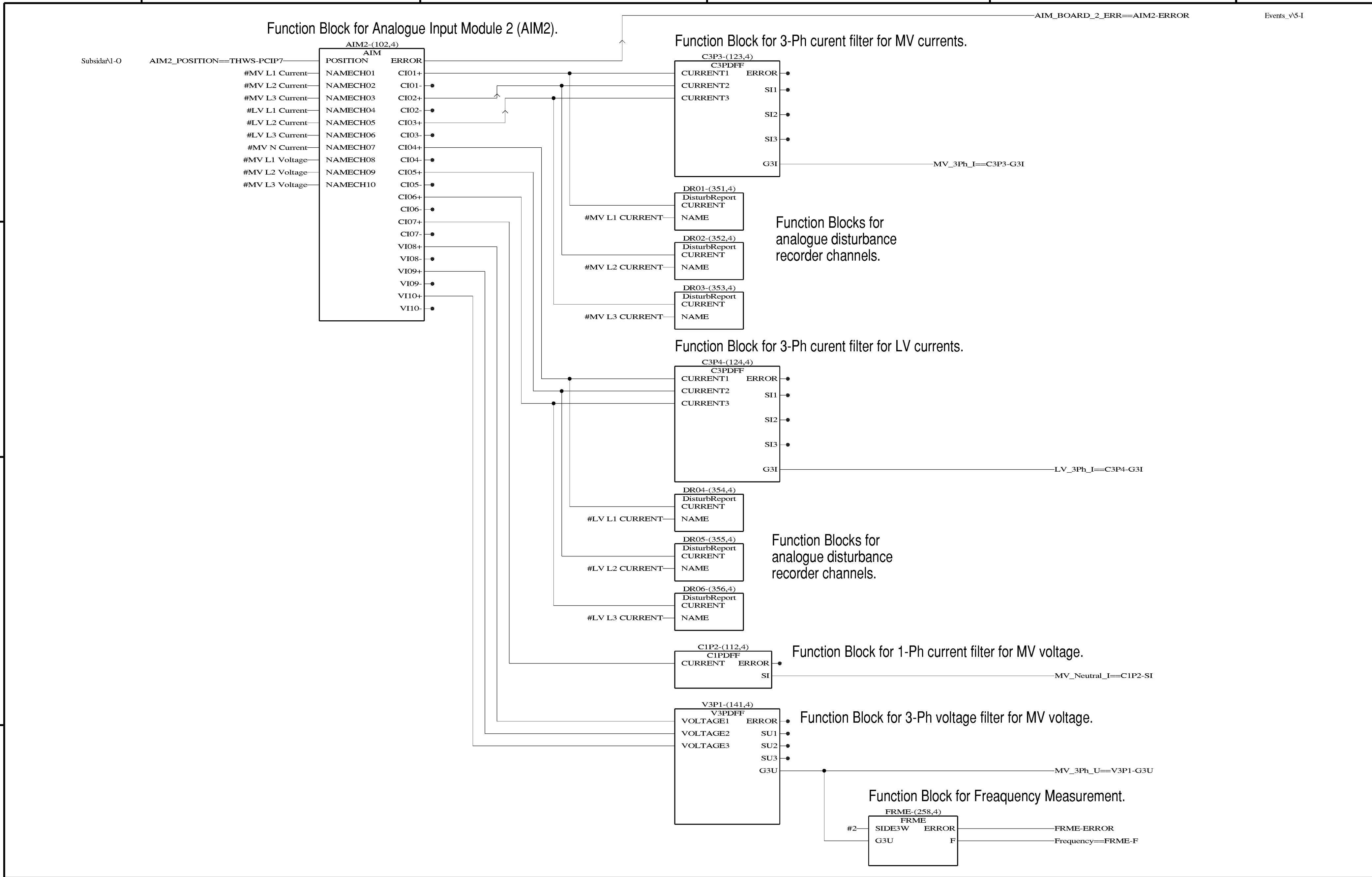
All 10 analogue input signals are connected to the disturbance recorder. In addition to that 48 binary signals are connected to the disturbance recorder as well.

Finally binary events to the substation control system which will be automatically reported via LON bus are configured.

Prepared		02-04-20	RET521 2p4		Overall_
Approved	Birger Hillström	02-04-25		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 4	Sheet 2/2
Based on	Pcl				

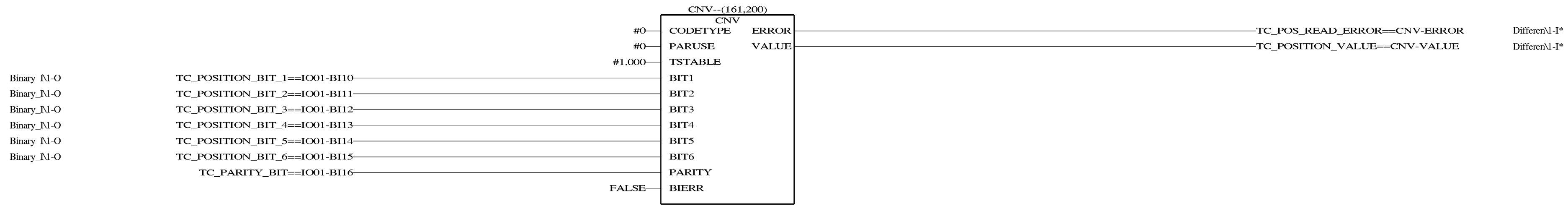


Rev Ind	Reg nr	Prepared	02-04-20	RET521 2p4
Based on	Pcl	Approved Birger Hillström	02-04-25	ABB Autom. Techn. Prod. AB
Analogue				
Resp dep	SA/ATA	Rev Ind		
Example 4		Sheet 1/2		



Prepared		02-04-20	RET521 2p4	Analogue
Approved	Birger Hillström	02-04-25		
Rev Ind	Reg nr		Resp dep SA/ATA	Rev Ind
Based on	Pcl		ABB Autom. Techn. Prod. AB	Example 4	Sheet 2/2

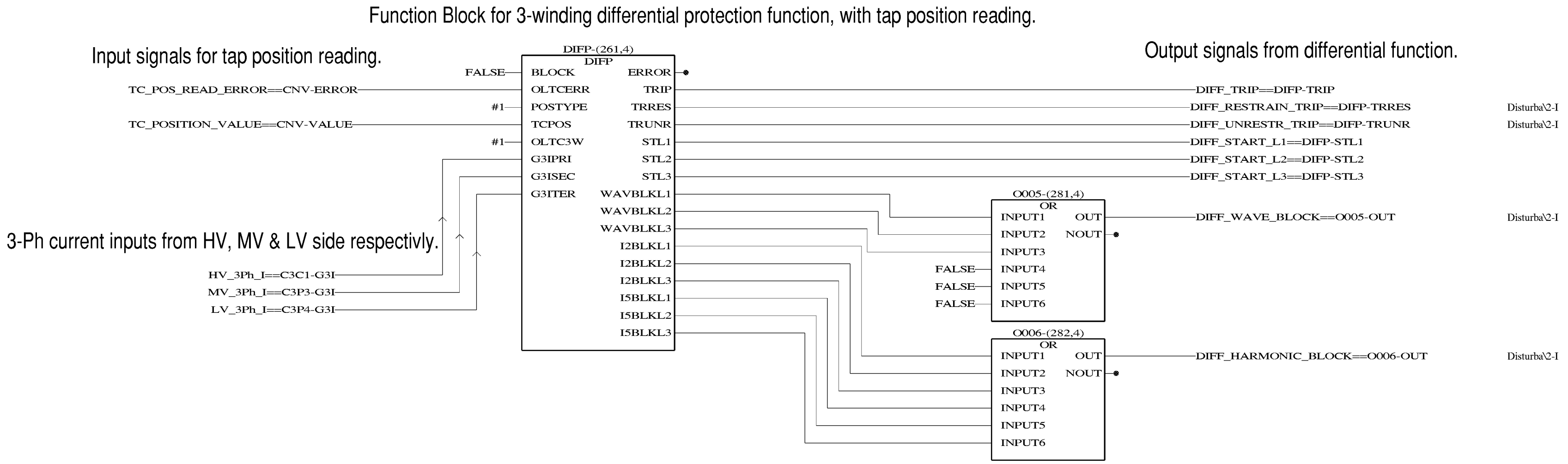
Function Block for Convertor.



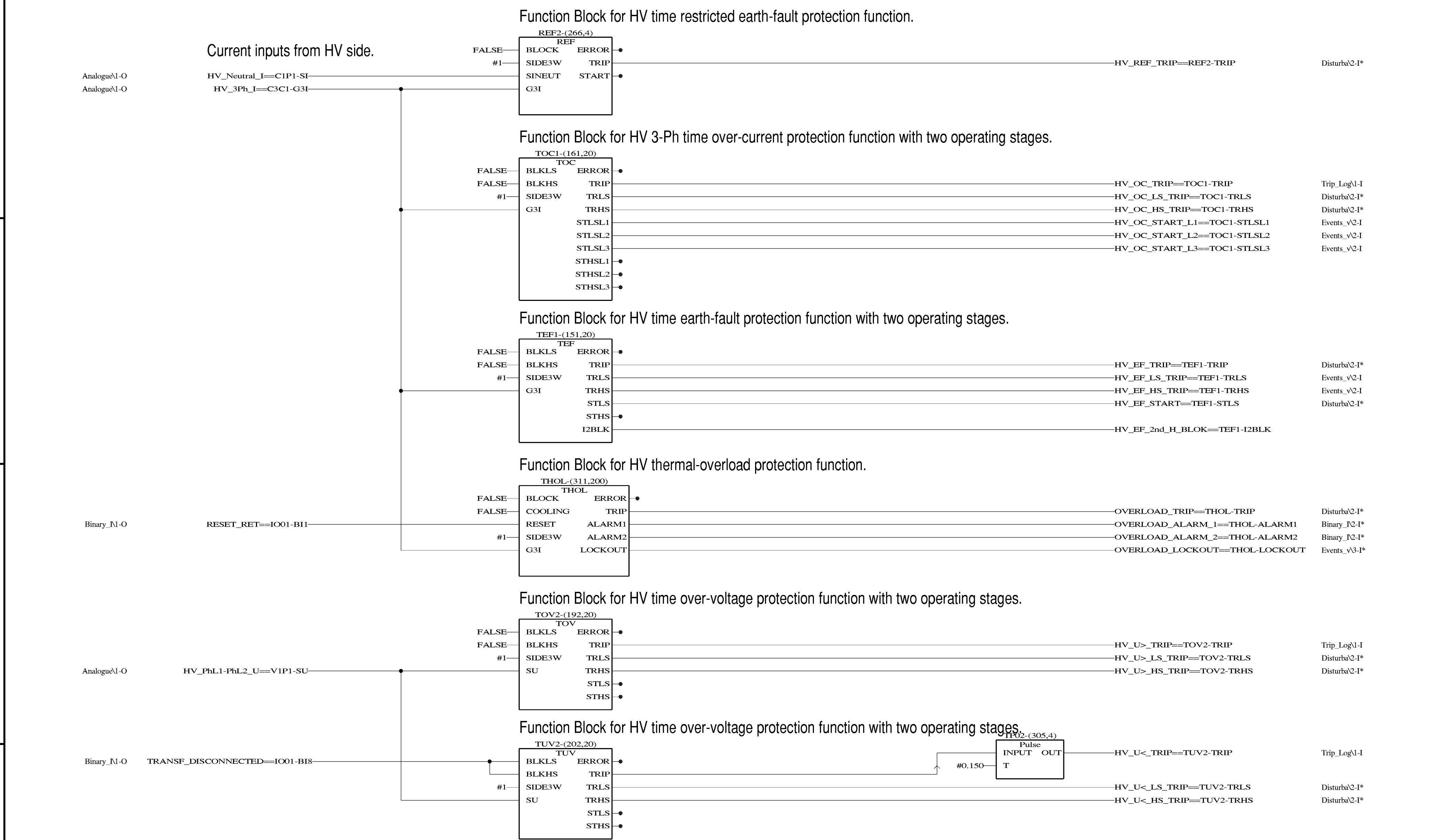
This function block is used here to convert six binary input signals into the tap position value.
As configured here, binary number will be converted into intiger number (0-63).

Value of tap position is then given to differential protection function and
voltage control function in order to enhance their functionality.

Rev Ind		Reg nr	Prepared	02-04-20	RET521 2p4
Based on		Pcl	Approved Birger Hillström	02-04-25	
Resp dep	SA/ATA	Rev Ind	Reading_	Sheet 1/1	
ABB Autom. Techn. Prod. AB	Example 4				

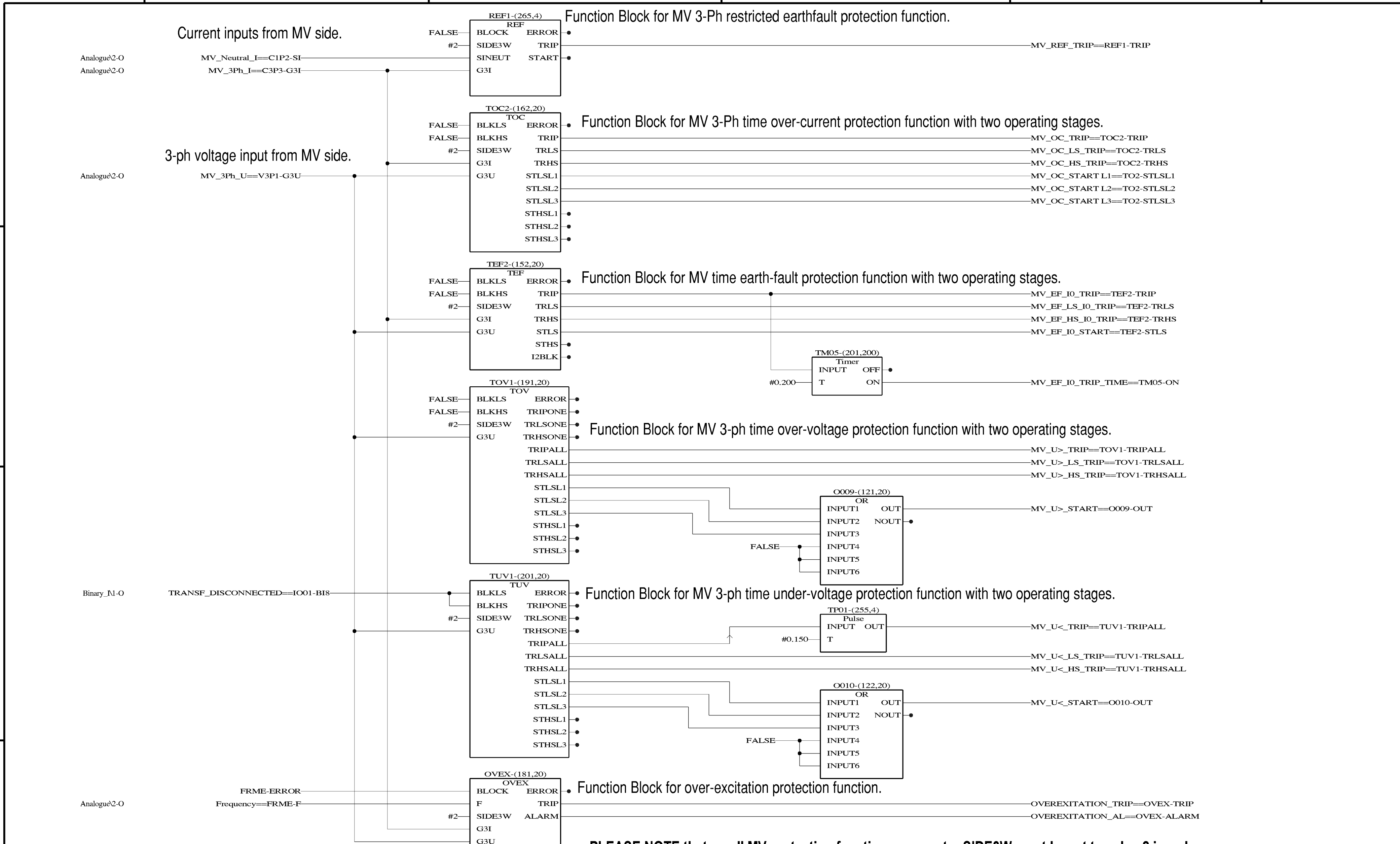


Rev Ind	Reg nr	Prepared	02-04-20	RET521 2p4	Differen
Based on	Pcl	Approved Birger Hillström	02-04-25	ABB Autom. Techn. Prod. AB	Resp dep SA/ATA Rev Ind
					Example 4
					Sheet 1/1



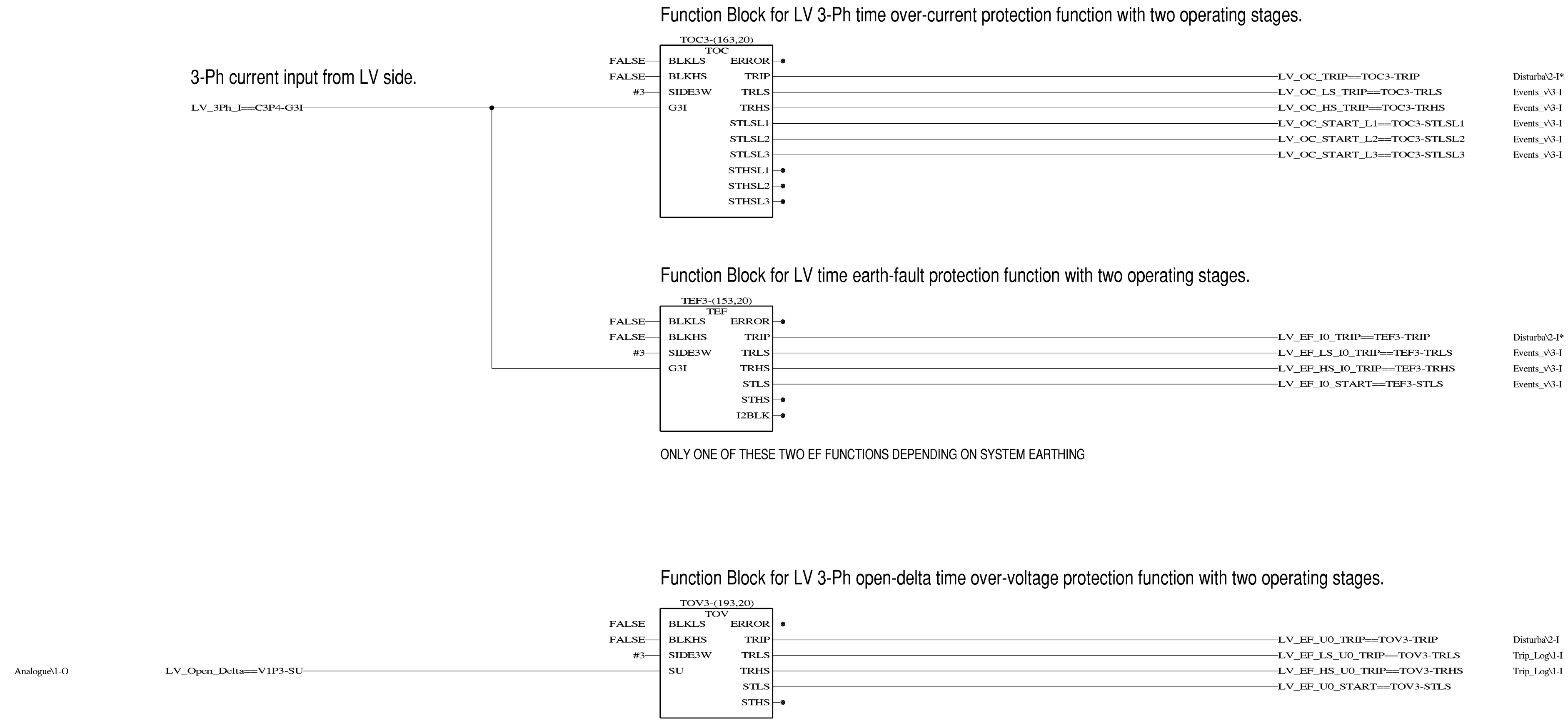
PLEASE NOTE that on all HV protection functions parameter SIDE3W must be set to value 1 in order to indicate to the respective function that it is connected to the HV (i.e. primary) side of the power transformer.

Prepared	02-04-20	RET521 2p4	HV_Prote
Approved Birger Hillström	02-04-25		
Rev Ind	Reg nr	Resp dep SA/ATA	Rev Ind
Based on	Pcl	ABB Autom. Techn. Prod. AB	Example 4 / Sheet 1/1



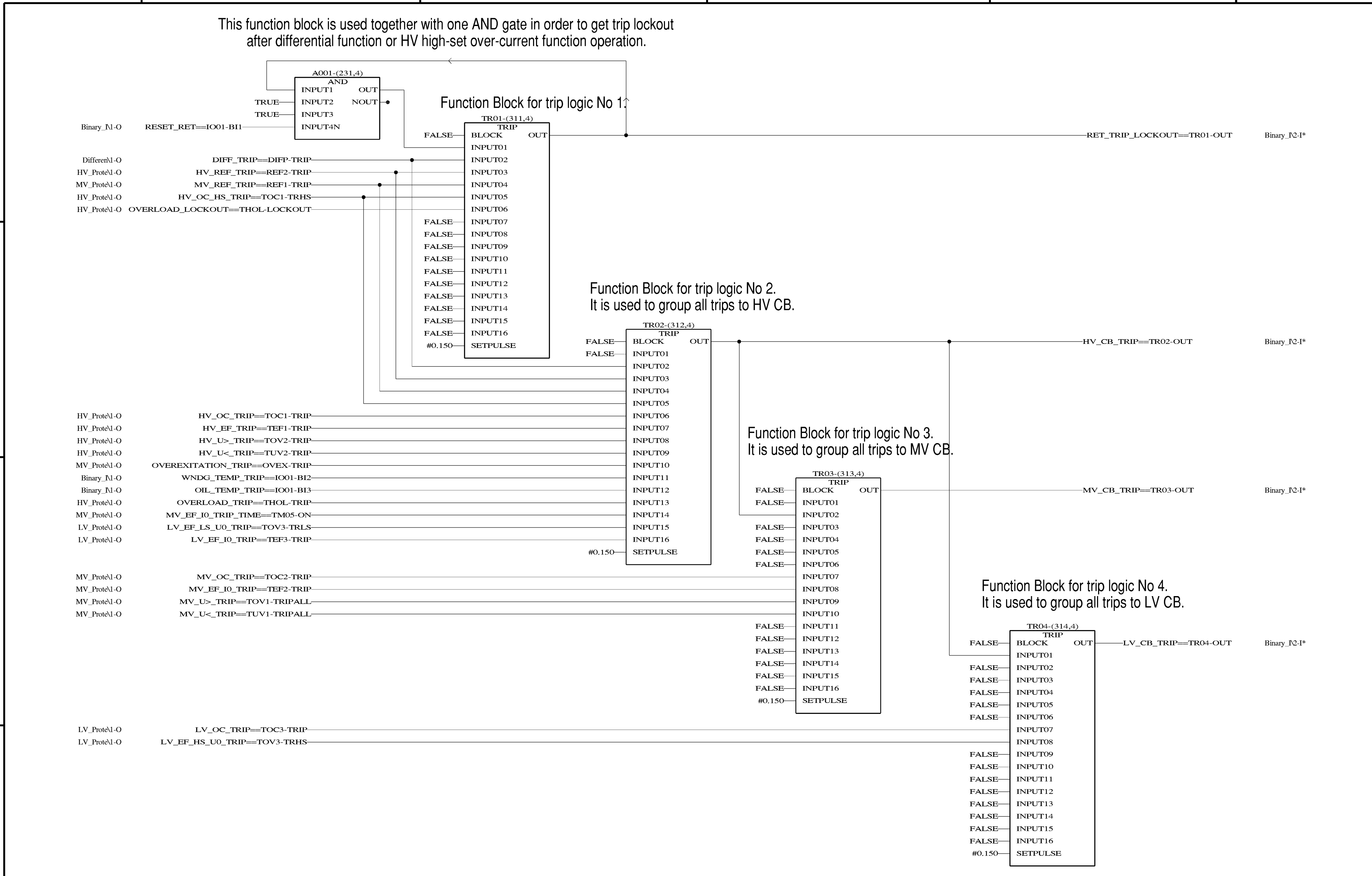
PLEASE NOTE that on all MV protection functions parameter SIDE3W must be set to value 2 in order to indicate to the respective function that it is connected to the MV (i.e. secondary) side of the power transformer.

	Prepared		02-04-20	RET521 2p4	MV_Prote
	Approved	Birger Hillström	02-04-25		Resp dep SA/ATA, Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 4, Sheet 1/1
Based on	Pcl				



PLEASE NOTE that on all LV protection functions parameter SIDE3W must be set to value 3 in order to indicate to the respective function that it is connected to the LV (i.e. tertiary) side of the power transformer.

Prepared		02-04-20	RET521 2p4	LV_Prote
Approved	Birger Hillström	02-04-25		
Rev Ind	Reg nr		Resp dep SA/ATA	Rev Ind
Based on	Pcl		ABB Autom. Techn. Prod. AB	Example 4	Sheet 1/1



Prepared		02-04-20	RET521 2p4
Approved	Birger Hillström	02-04-25	
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB
Based on	Pcl		

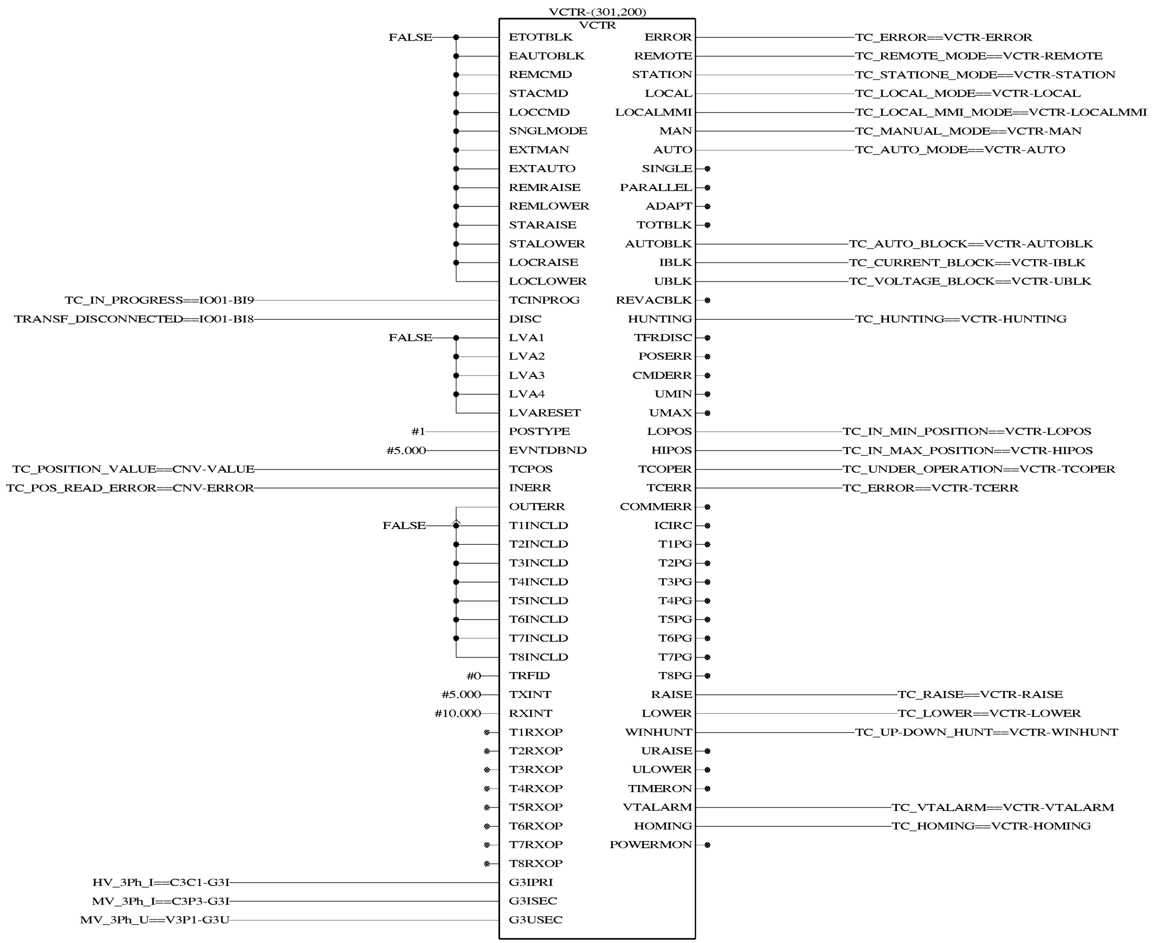
Trip_Log

Resp dep SA/ATA | Rev Ind

Example 4

Sheet 1/1

Function Block for MV side voltage control function (i.e. tap changer control function).
VCTR parallel for maximum 8 parallel transformers



Rev Ind		Reg nr	Prepared	02-04-20
Based on		Pcl	Approved Birger Hillström	02-04-25

RET521 2p4

ABB Autom. Techn. Prod. AB

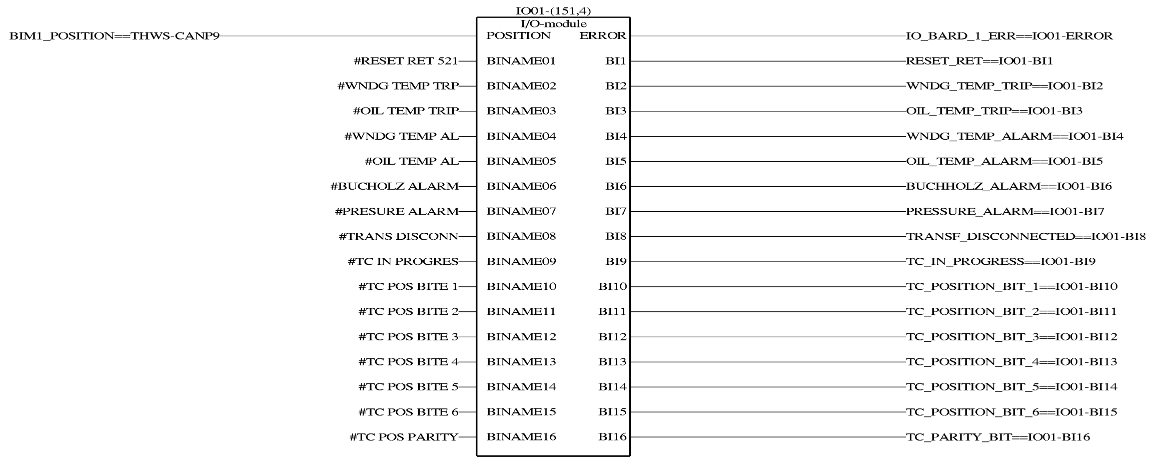
Voltage_

Resp dep SA/ATA | Rev Ind

Example 4

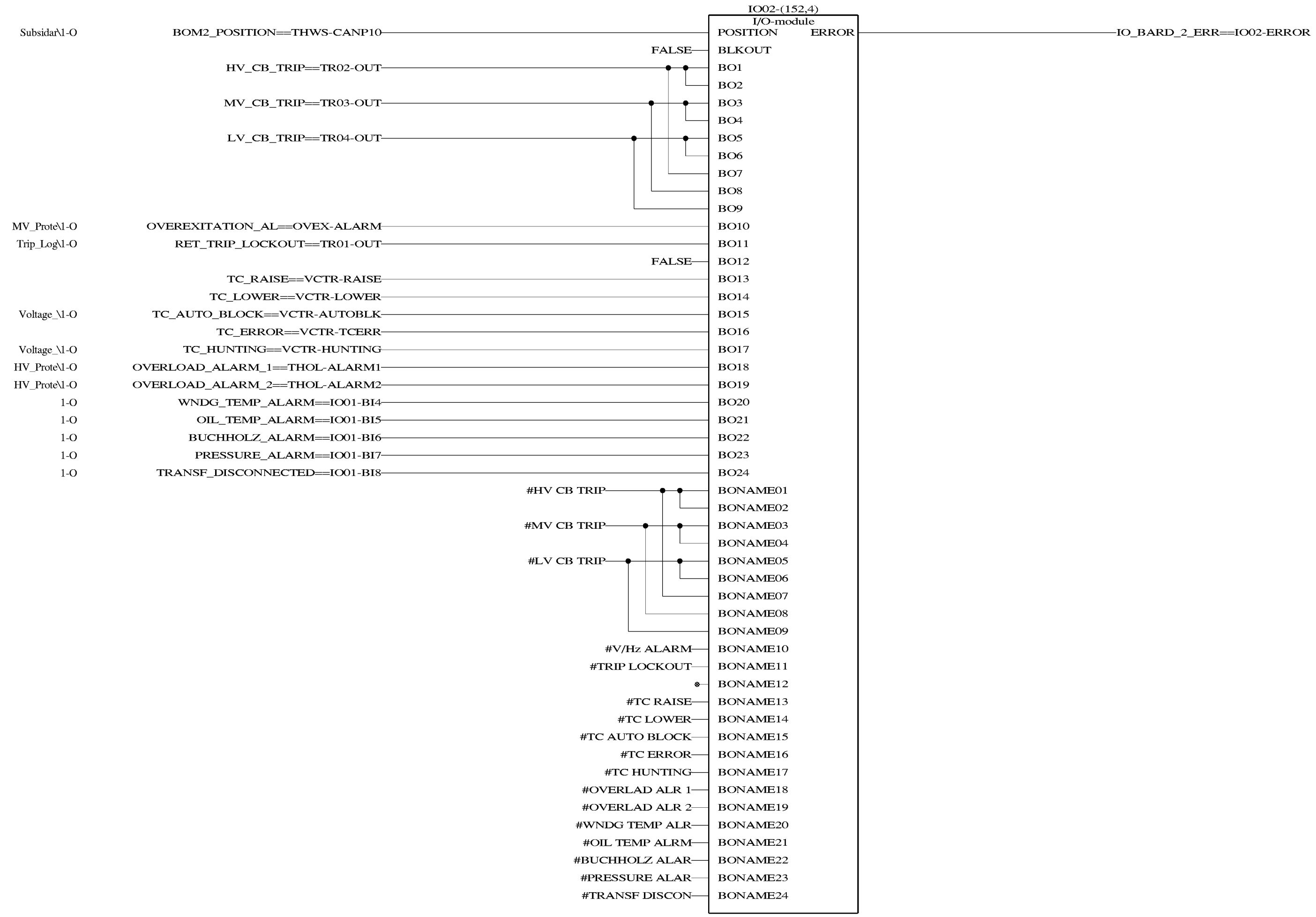
Sheet 1/1

Function Block for Binary Input Module (BIM) with 16 optocoupler inputs.



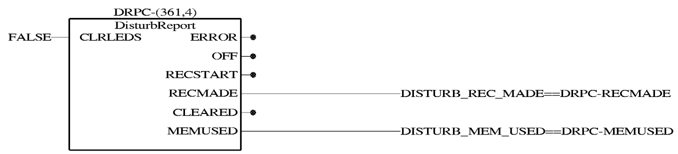
Prepared 02-04-20
Approved Birger Hillström 02-04-25
Rev Ind
Based on
Reg nr
Pcl
RET521 2p4
ABB Autom. Techn. Prod. AB
Resp dep SA/ATA
Rev Ind
Example 4
Binary_I
Sheet 1/2

Function Block for Binary Output Module (BOM) with 24 contact outputs.



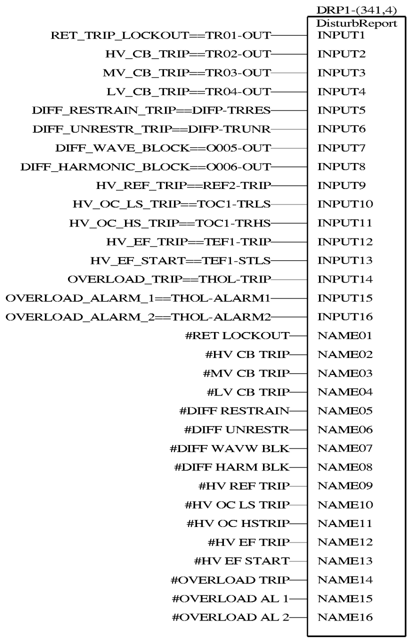
		Prepared	02-04-20	RET521 2p4	Binary_I
		Approved Birger Hillström	02-04-25		
					Resp dep SA/ATA Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 4 Sheet 2/2
Based on	Pcl				

Function Block for Disturbance Report function.
It provides binary indication when new recording is made and when avaiable memory is used.

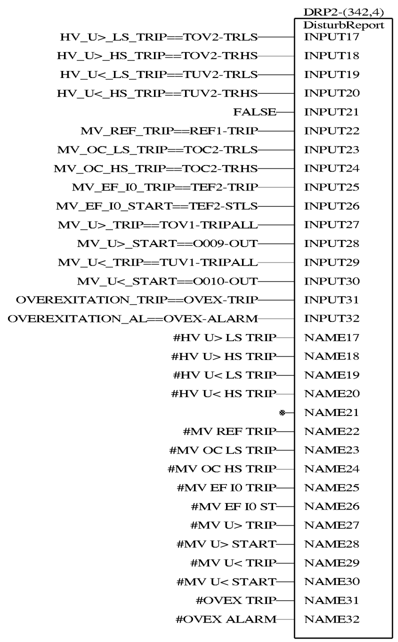


Prepared	02-04-20	RET521 2p4		Disturba
Approved Birger Hillström	02-04-25		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr	ABB Autom. Techn. Prod. AB	Example 4	Sheet 1/2
Based on	Pcl			

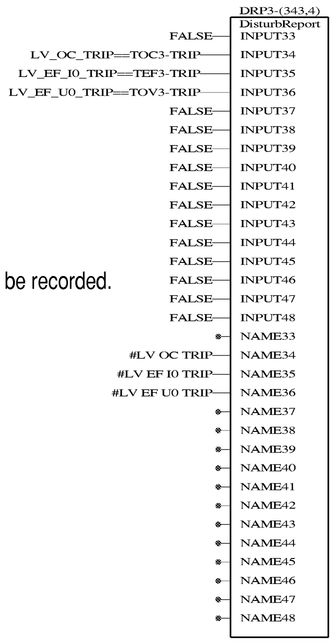
Function Block for Disturbance Report function No 1.
It is possible to connect first lot of 16 binary signals which shall be recorded.



Function Block for Disturbance Report function No 2.
It is possible to connect second lot of 16 binary signals which shall be recorded.

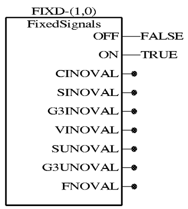


Function Block for Disturbance Report function No 3.
It is possible to connect tird lot of 16 binary signals which shall be recor

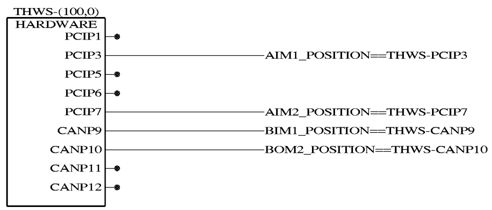


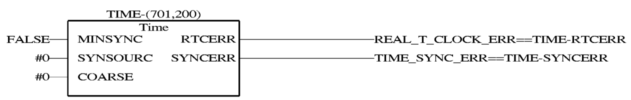
Prepared	02-04-20	RET521 2p4	Disturba
Approved Birger Hillström	02-04-25		Resp dep SA/ATA Rev Ind
Rev Ind Reg nr		ABB Autom. Techn. Prod. AB	Example 4 Sheet 2/2
Based on Pcl			

Function Block for fixed signals.
It defines binary zero (i.e. FALSE) and binary one (i.e. TRUE) values.



Function Block for terminal hardware structure.
It defines internal positions of all ordered hardware modules.
(i.e. AIM1, BIM1, BOM1 & MIM in this configuration)





Function Block for terminal "Test Mode"

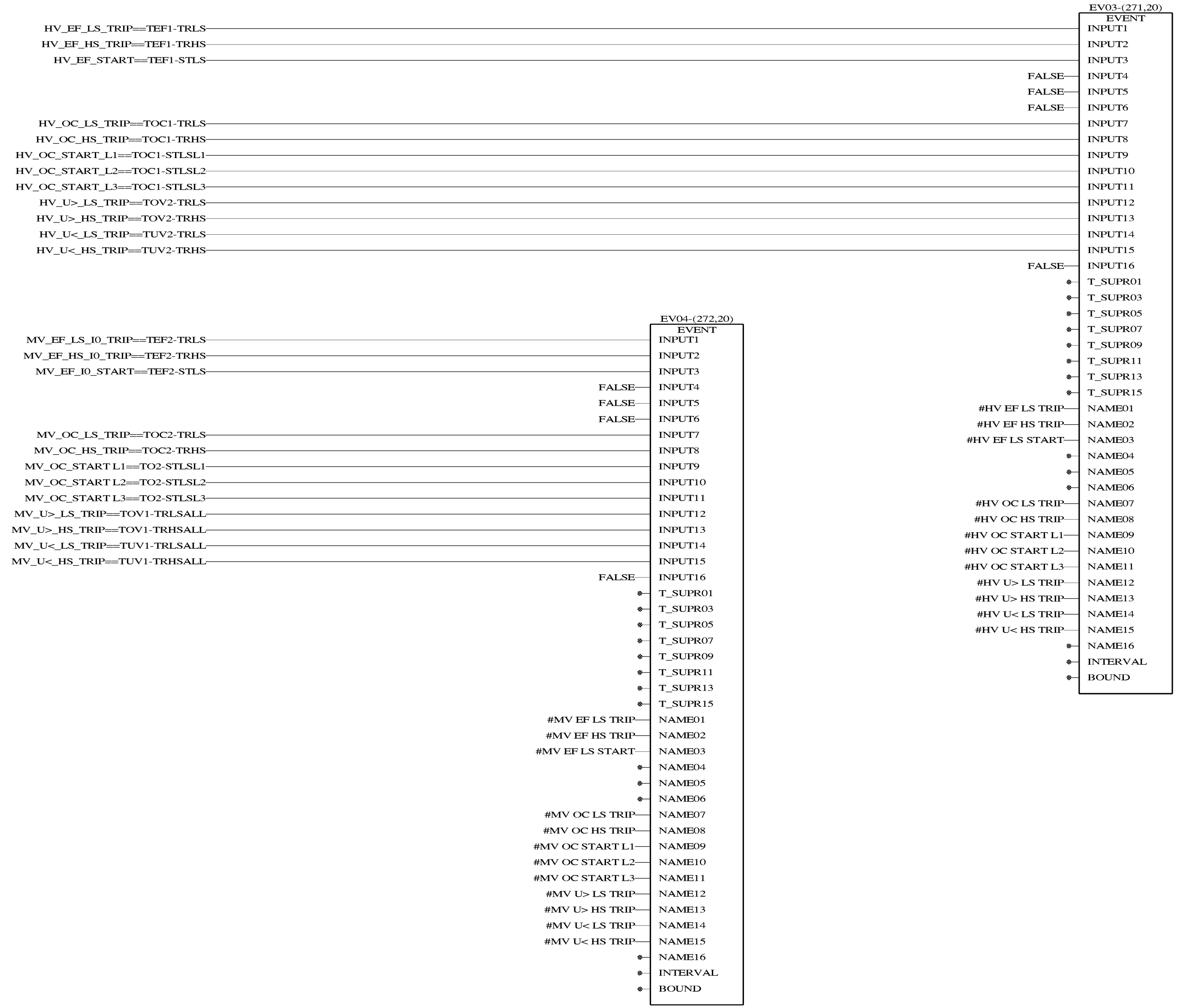
Function Block for synchronization of terminal internal real time clock.

Prepared	02-04-20	RET521 2p4		Subsidar
Approved Birger Hillström	02-04-25		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr	ABB Autom. Techn. Prod. AB	Example 4	Sheet 1/1
Based on	Pcl			

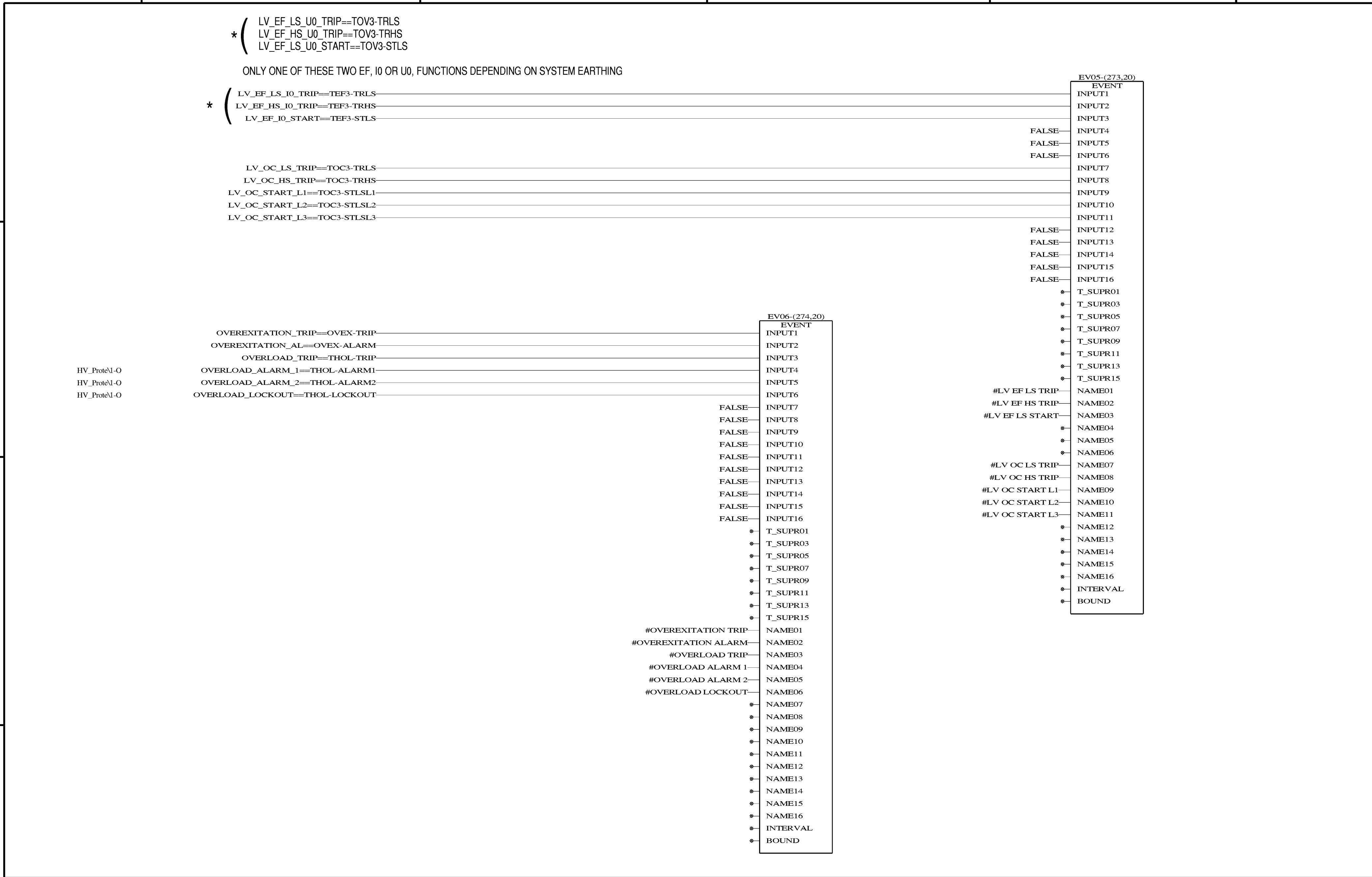
All EVENT blocks in this worksheet are used to report the selected internal binary signals to Substation Control System via LON bus.

If rear LON port is not ordered or it is not connected to SCS then this worksheet has no any meaning.

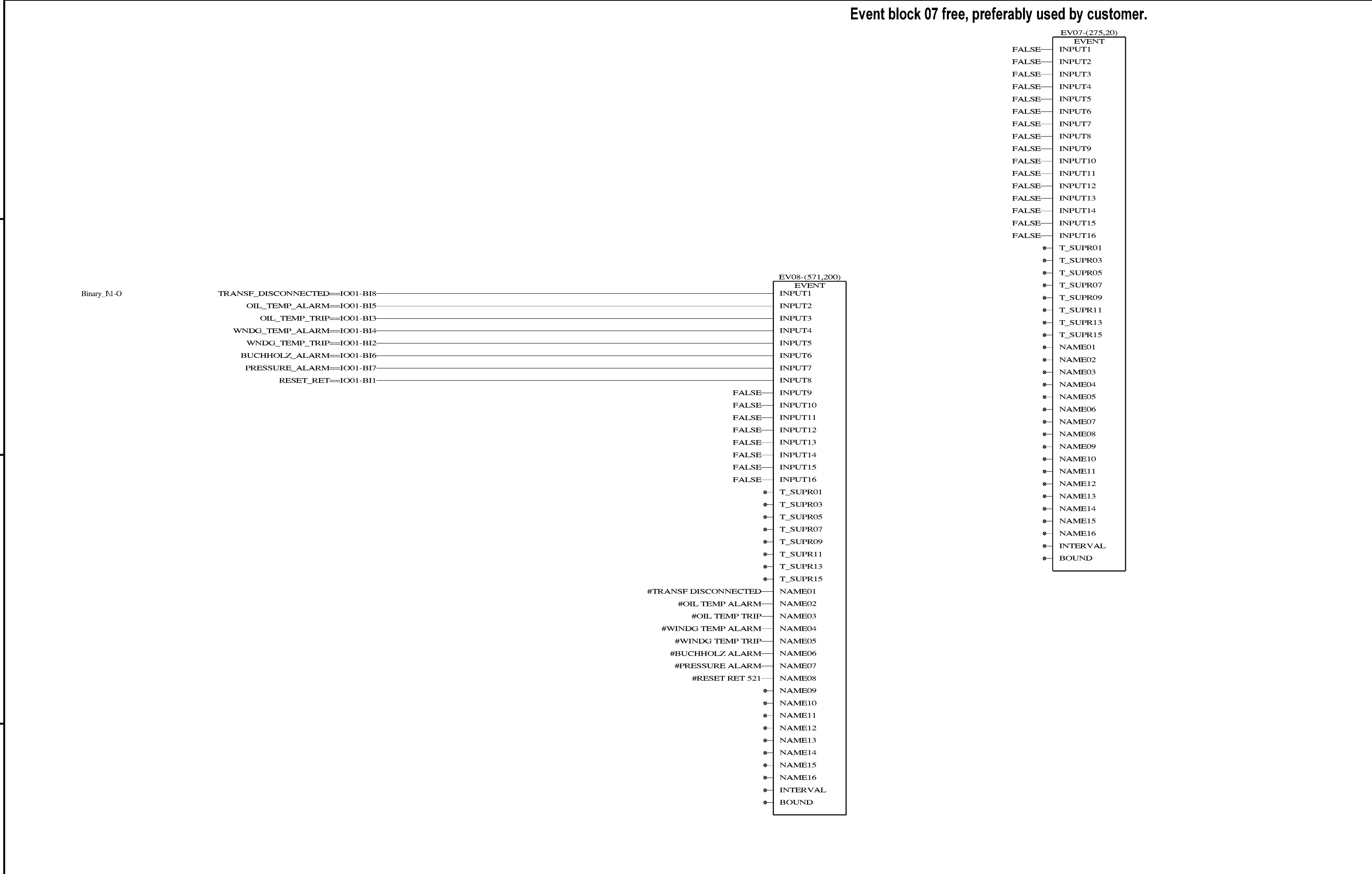
Prepared		02-04-20	RET521 2p4		Events_v
Approved	Birger Hillström	02-04-25		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 4	Sheet 1/6
Based on	Pcl				



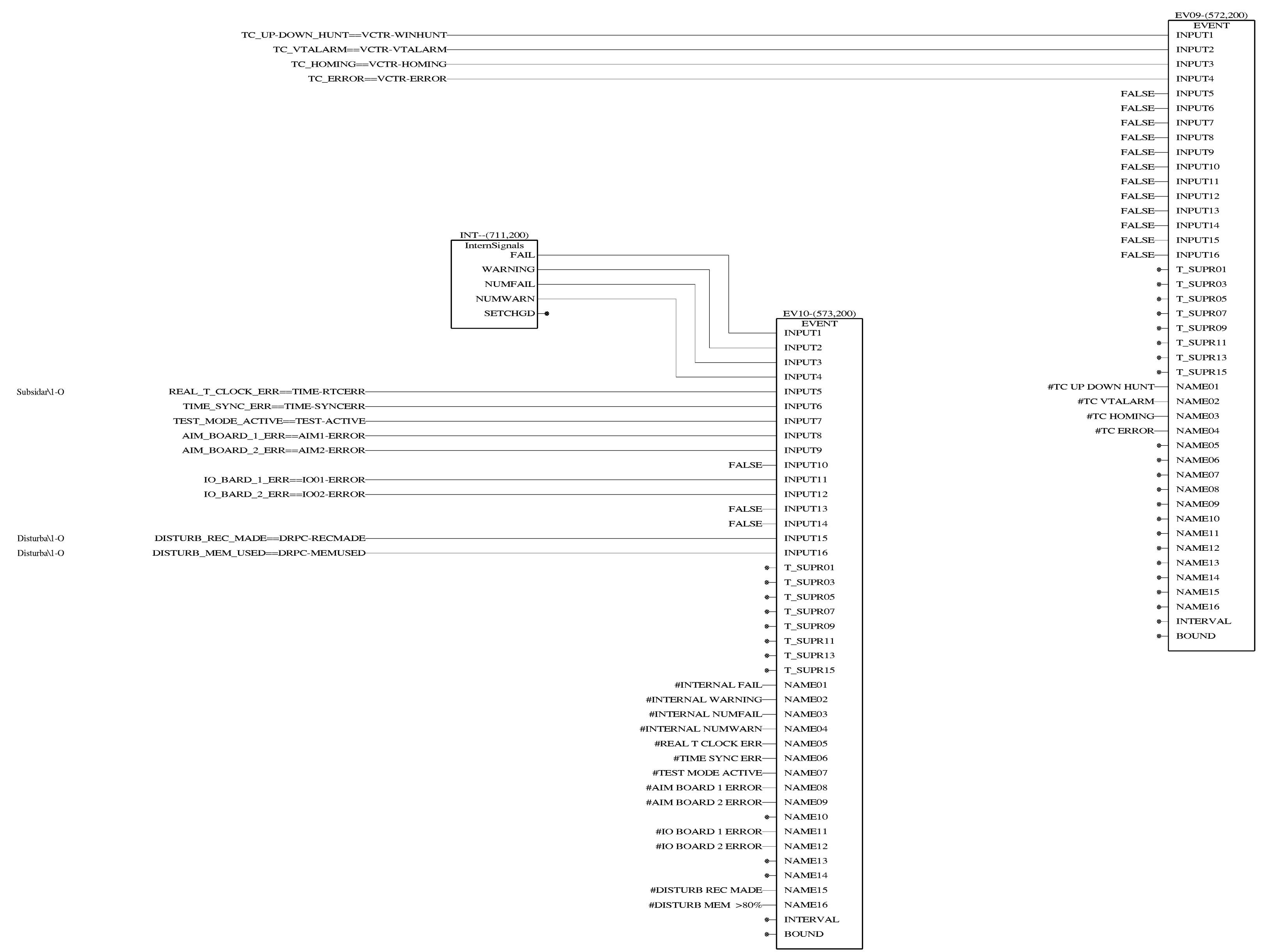
Prepared	02-04-20	RET521 2p4		Events_v
Approved Birger Hillström	02-04-25			
Rev Ind	Reg nr		Resp dep SA/ATA	Rev Ind
Based on	Pcl	ABB Autom. Techn. Prod. AB	Example 4	Sheet 2/6



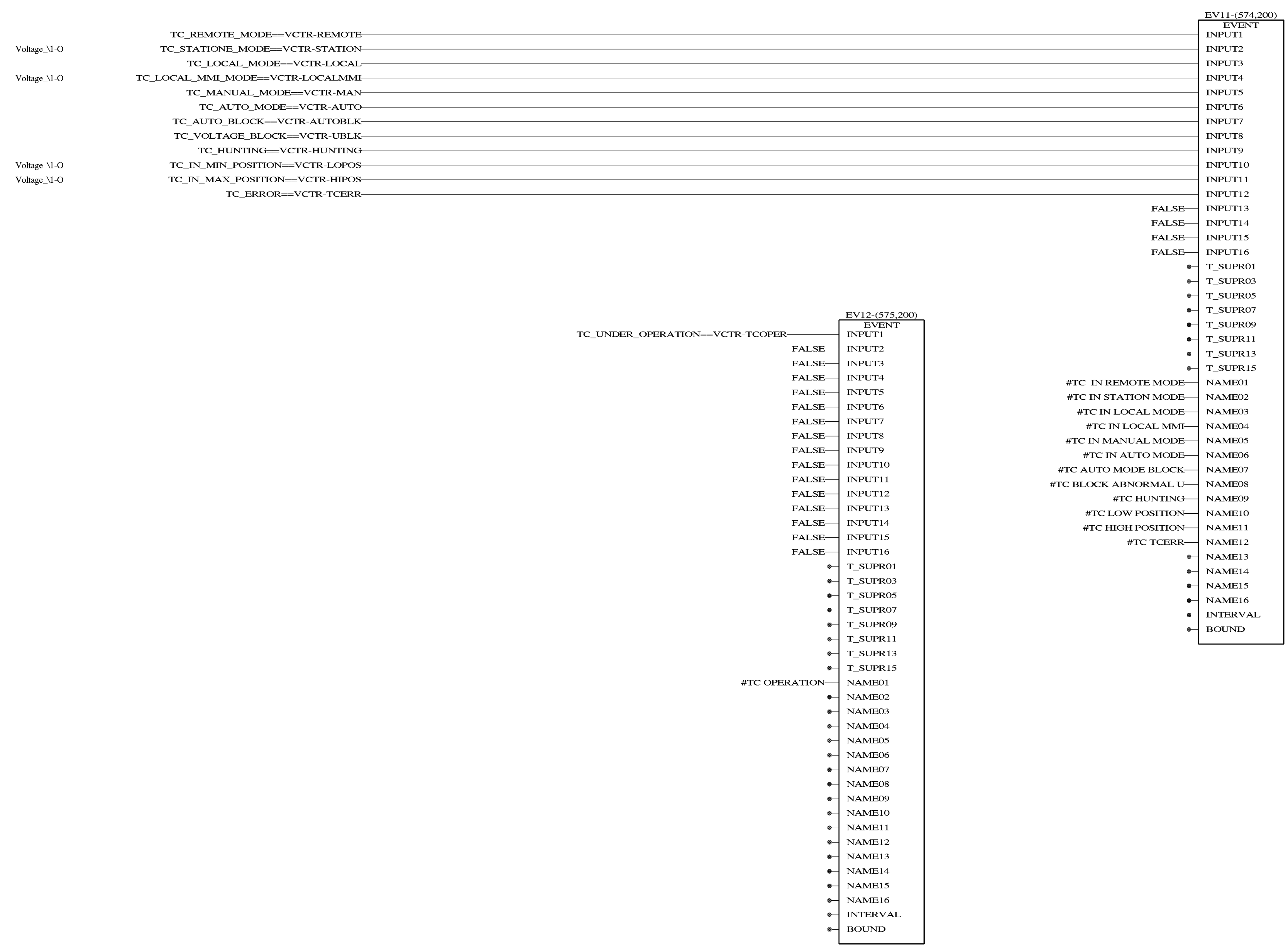
Prepared		02-04-20	RET521 2p4	Events_v
Approved	Birger Hillström	02-04-25		
Rev Ind	Reg nr		Resp dep SA/ATA	Rev Ind
Based on	Pcl		ABB Autom. Techn. Prod. AB	Example 4 / Sheet 3/6



Prepared	02-04-20	RET521 2p4	Events_v
Approved Birger Hillström	02-04-25		
Rev Ind	Reg nr		Resp dep SA/ATA Rev Ind
Based on	Pcl	ABB Autom. Techn. Prod. AB	Example 4 Sheet 4/6



		Prepared	02-04-20	RET521 2p4	Events_v
		Approved Birger Hillström	02-04-25		
					Resp dep SA/ATA Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 4 Sheet 5/6
Based on	Pcl				



	Prepared	02-04-20	RET521 2p4		Events_v
	Approved Birger Hillström	02-04-25		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 4	Sheet 6/6
Based on	Pcl				

Description Example Config no 5 (1MRK 001 536-26)	Work Sheet No
List of Content	Sheet No 01
Short Configuration Description	Sheet No 02
Configuration of Current & Voltage Signals	Sheet No 03 & 04
Reading of Tap Position	Sheet No 05
Differential Protection Function	Sheet No 06
HV Protection Functions	Sheet No 07
MV Protection Functions	Sheet No 08 & 09
LV Protection Functions	Sheet No 10
Tripping Logic	Sheet No 11
Voltage Control Function	Sheet No 12
Configuration of Binary Input Module	Sheet No 13
Configuration of Binary Output Module	Sheet No 14
Configuration of Disturbance Report	Sheet No 15 & 16
Subsidary Configuration	Sheet No 17
Configuration of Event Reporting via LON bus	Sheet No 18 to 23

Prepared	02-04-20	RET521 2p4	Overall_
Approved Birger Hillström	02-04-25		Resp dep SA/ATA Rev Ind
Rev Ind	Reg nr	ABB Autom. Techn. Prod. AB	Example 5
Based on	Pcl		Sheet 1/2

Short configuration description

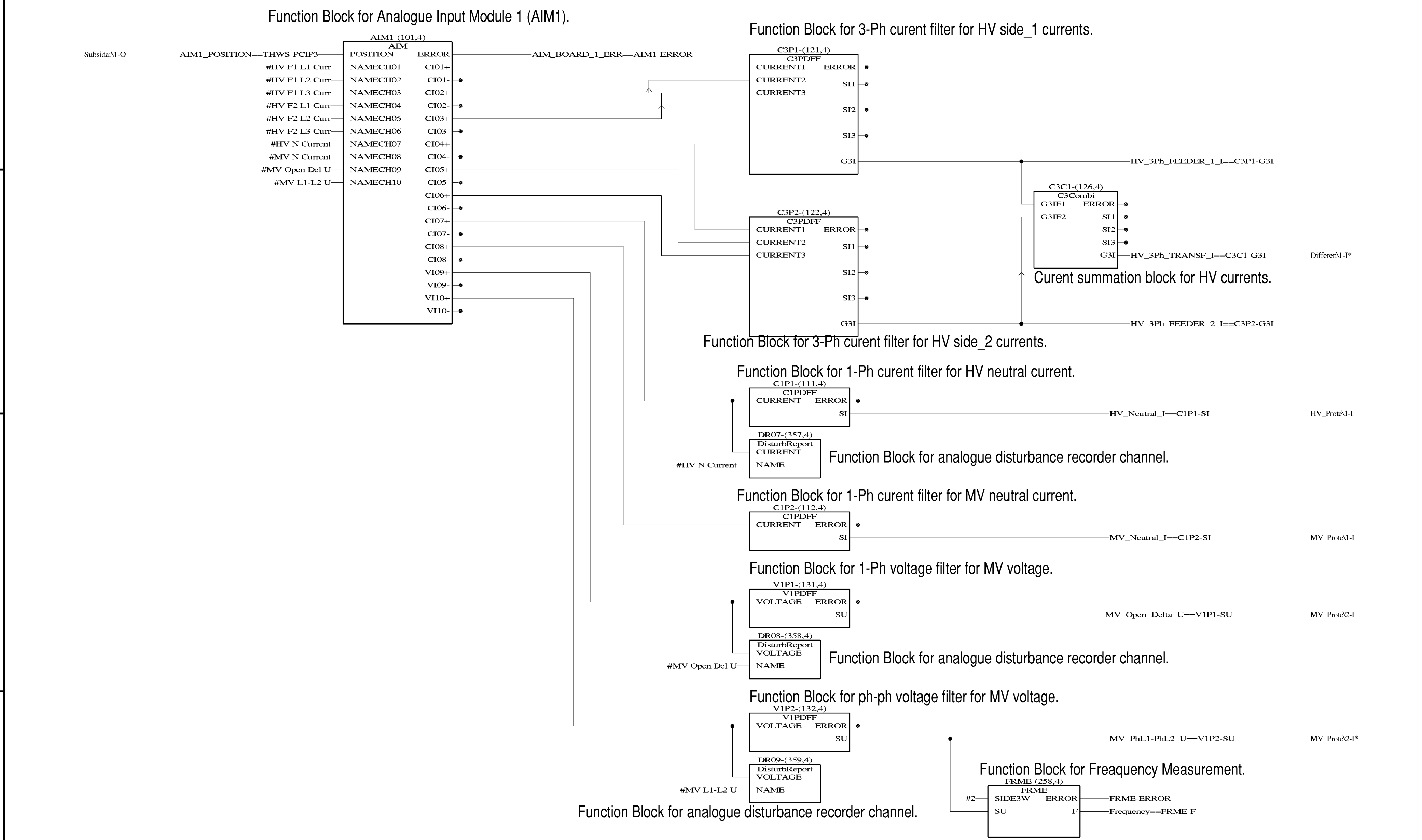
The example configuration No 5 is made for protection and control of a three winding power transformer with "T" HV & MV CTs.
In the RET 521 terminal the following hardware modules are included: AIM1 (8I+2U), AIM2 (9I+1U), BIM & BOM.
It is assumed that analogue inputs are connected to the following order to AIM1 module: HV_IL1_side1, HV_IL2_side1, HV_IL3_side1, HV_IL1_side2, HV_IL2_side2, HV_IL3_side2, HV Neutral Current, MV Neutral Current, MV_Uopen_delta, & MV_UL1-L2. To the AIM2 the following analogue inputs are connected: MV_IL1_side1, MV_IL2_side1, MV_IL3_side1, MV_IL1_side2, MV_IL2_side2, MV_IL3_side2, LV_IL1, LV_IL2, LV_IL3 & MV-Uopen_delta.
The following protection and control function are included in the configuration:
Transformer differential protection with five restrained inputs (87T & 87H); HV restricted earth fault protection (87N);
MV restricted earth fault protection (87N); Transformer 3-Ph HV OC protection (50, 51); Transformer HV EF protection (50N, 51N);
Thermal overload protection (49); Transformer 3-Ph MV OC protection (50, 51); Transformer MV neutral EF protection (50N, 51N);
MV U< protection (27); MV U> protection (59); Overexcitation protection (24); MV 3Uo> protection (59N);
LV 3-Ph OC protection (50, 51); LV EF protection (50N, 51N); LV 3Uo> protection (59N); and MV side voltage control (90).
Individual tripping logic for all CBs are provided.

The tap changer position is monitored via six binary inputs (input pattern = BCD coded signal).

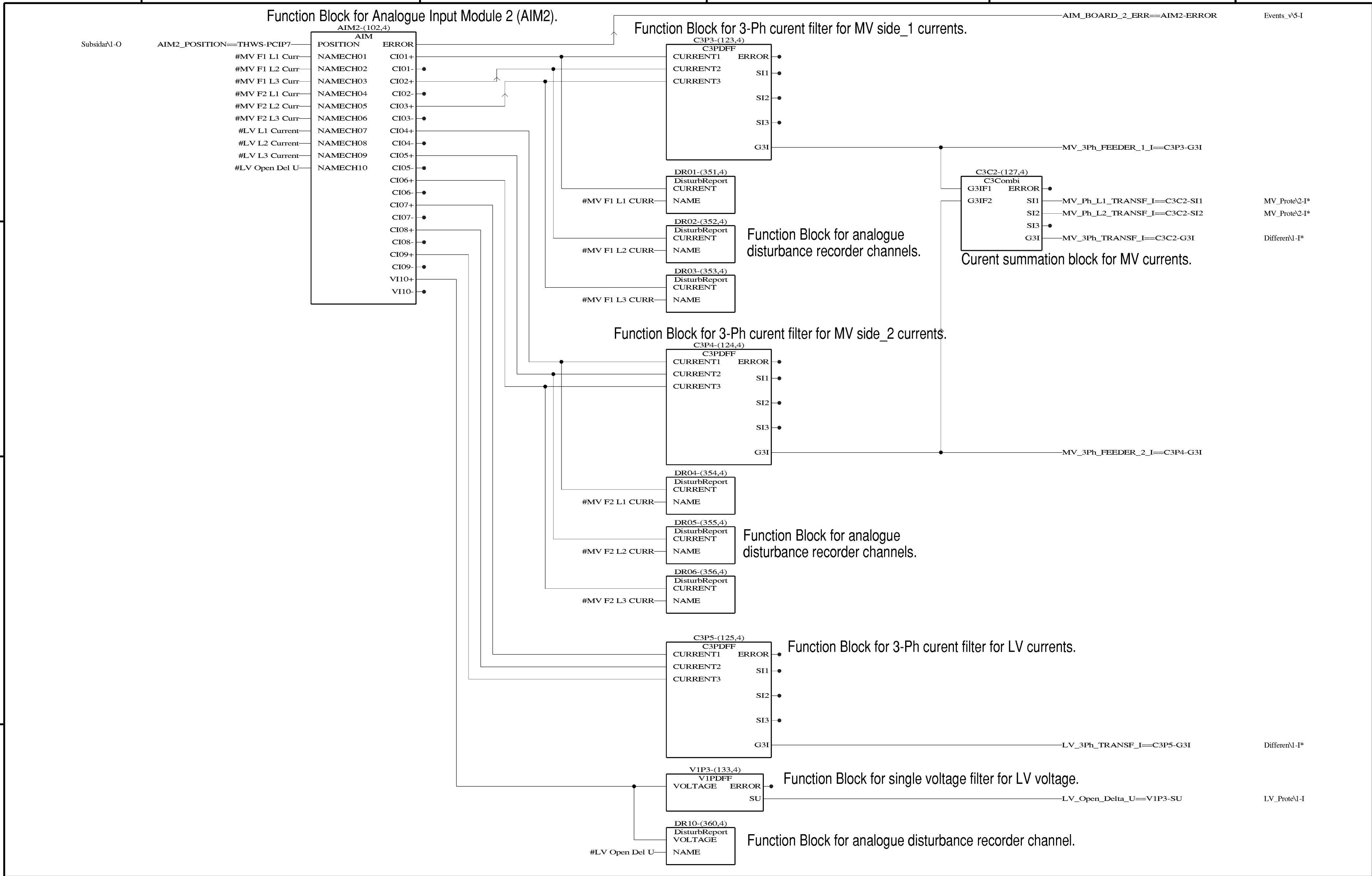
All 10 analogue input signals are connected to the disturbance recorder. In addition to that 48 binary signals are connected to the disturbance recorder as well.

Finally binary events to the substation control system which will be automatically reported via LON bus are configured.

Rev Ind	Reg nr	Prepared	02-04-20	RET521 2p4	Overall_
Based on	Pcl	Approved Birger Hillström	02-04-25	ABB Autom. Techn. Prod. AB	Resp dep SA/ATA; Rev Ind; Example 5; Sheet 2/2

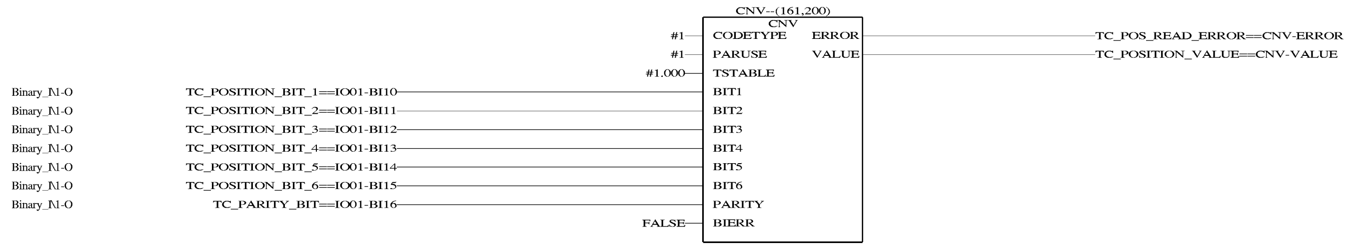


Prepared	02-04-20	RET521 2p4	Analogue
Approved Birger Hillström	02-04-25		Resp dep SA/ATA · Rev Ind
Rev Ind · Reg nr		ABB Autom. Techn. Prod. AB	Example 5 · Sheet 1/2
Based on · Pcl			



	Prepared	02-04-20	RET521 2p4	Analogue
	Approved Birger Hillström	02-04-25		
				Resp dep SA/ATA · Rev Ind
Rev Ind · Reg nr				Sheet 2/2
Based on · Pcl			ABB ABB Autom. Techn. Prod. AB	Example 5

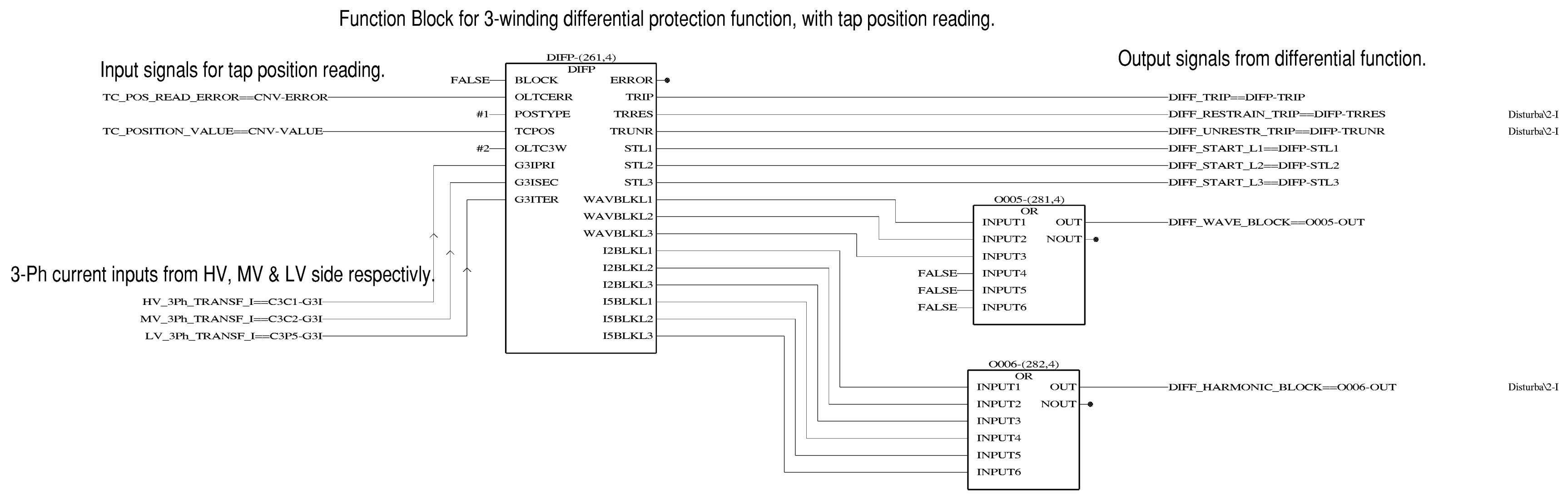
Function Block for Convertor.



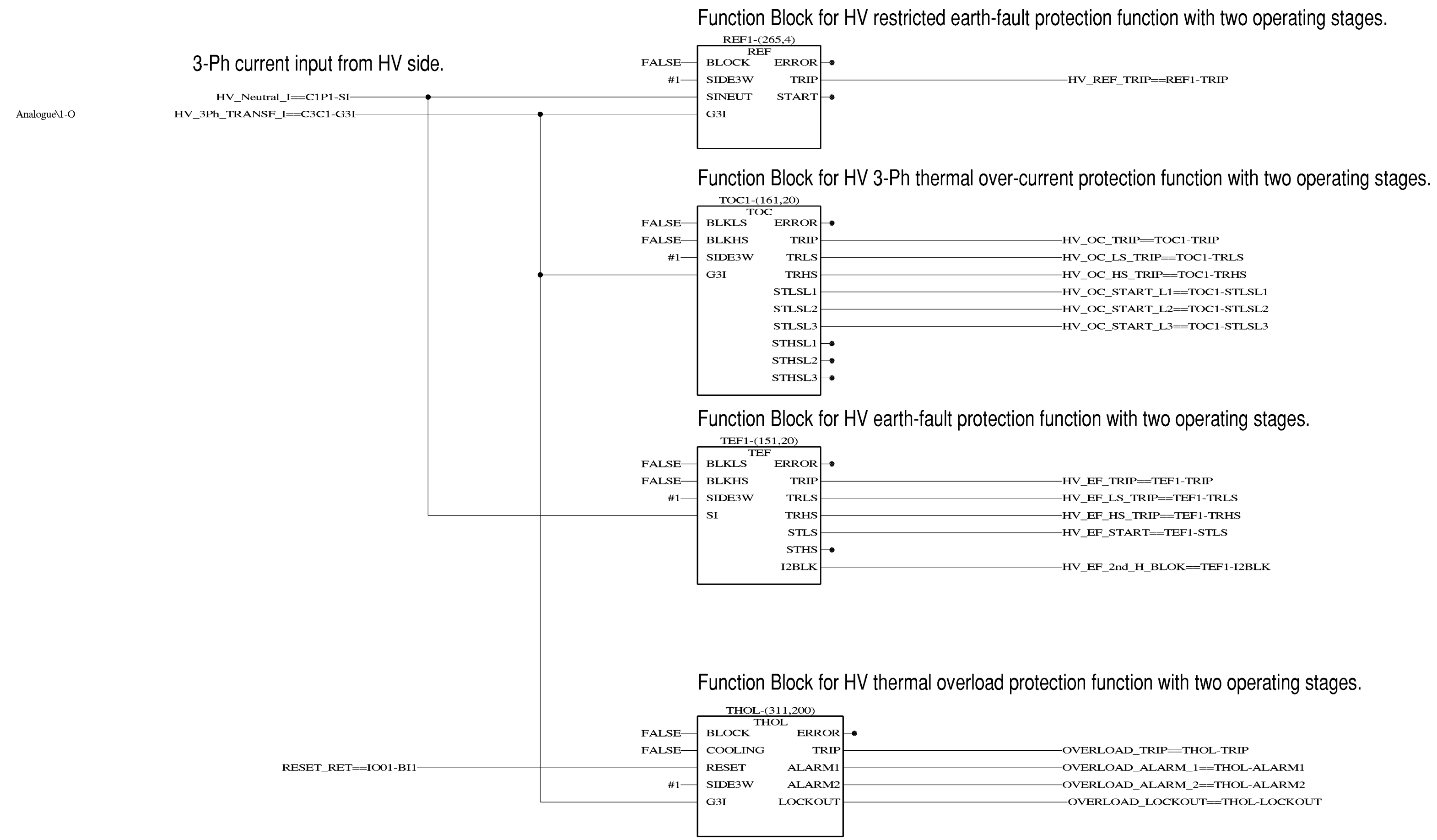
This function block is used here to convert six binary input signals into the tap position value.
As configured here, BCD coded signal will be converted into intiger number (0-39).

Value of tap position is then given to differential protection function and voltage control function in order to enhance their functionality.

		Prepared	02-04-20	RET521 2p4	Reading_
		Approved Birger Hillström	02-04-25		
					Resp dep SA/ATA Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 5 Sheet 1/1
Based on	Pcl				

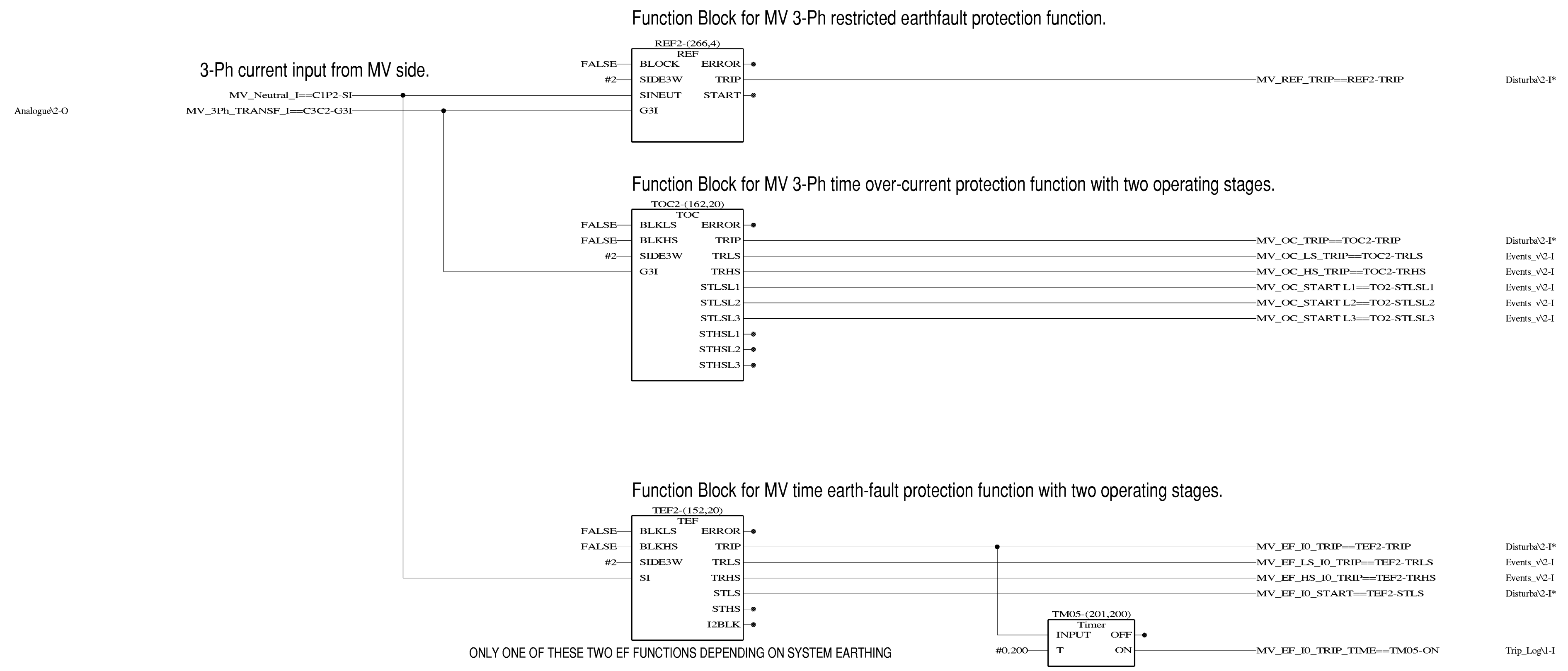


Rev Ind		Prepared	02-04-20	RET521 2p4	Differen
Based on	Reg nr	Approved Birger Hillström	02-04-25	ABB Autom. Techn. Prod. AB	Resp dep SA/ATA, Rev Ind
	Pcl				Example 5, Sheet 1/1



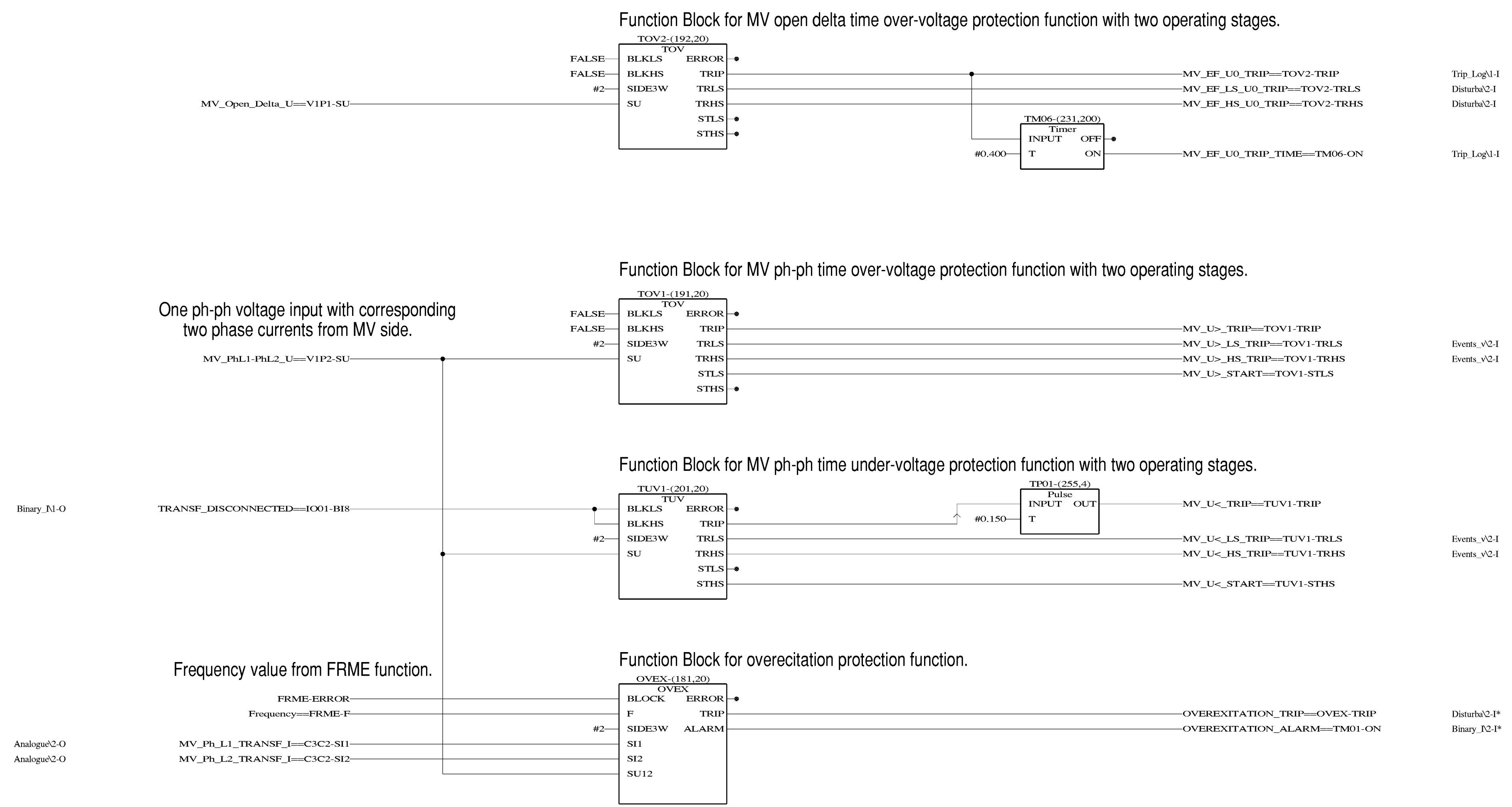
PLEASE NOTE that on all HV protection functions parameter SIDE3W must be set to value 1 in order to indicate to the respective function that it is connected to the HV (i.e. primary) side of the power transformer.

Rev Ind	Reg nr	Prepared 02-04-20	RET521 2p4	HV_Prote
Based on	Pcl	Approved Birger Hillström 02-04-25	ABB Autom. Techn. Prod. AB	Resp dep SA/ATA; Rev Ind
				Example 5; Sheet 1/1

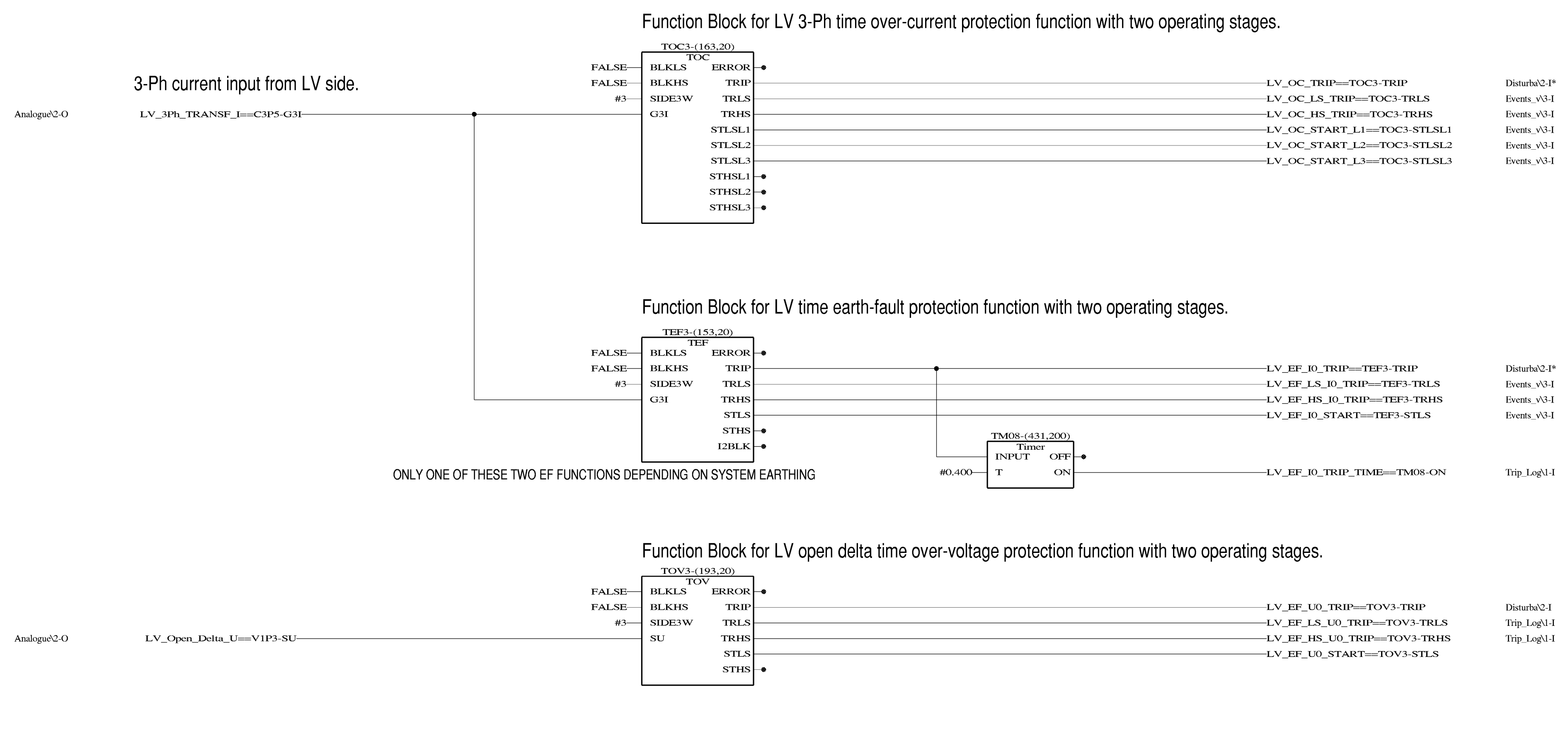


PLEASE NOTE that on all MV protection functions parameter SIDE3W must be set to value 2 in order to indicate to the respective function that it is connected to the MV (i.e. secondary) side of the power transformer.

Rev Ind	Reg nr	Prepared 02-04-20	RET521 2p4	Resp dep SA/ATA	MV_Prote
Based on	Pcl	Approved Birger Hillström 02-04-25	ABB Autom. Techn. Prod. AB	Rev Ind	Sheet 1/2
				Example 5	

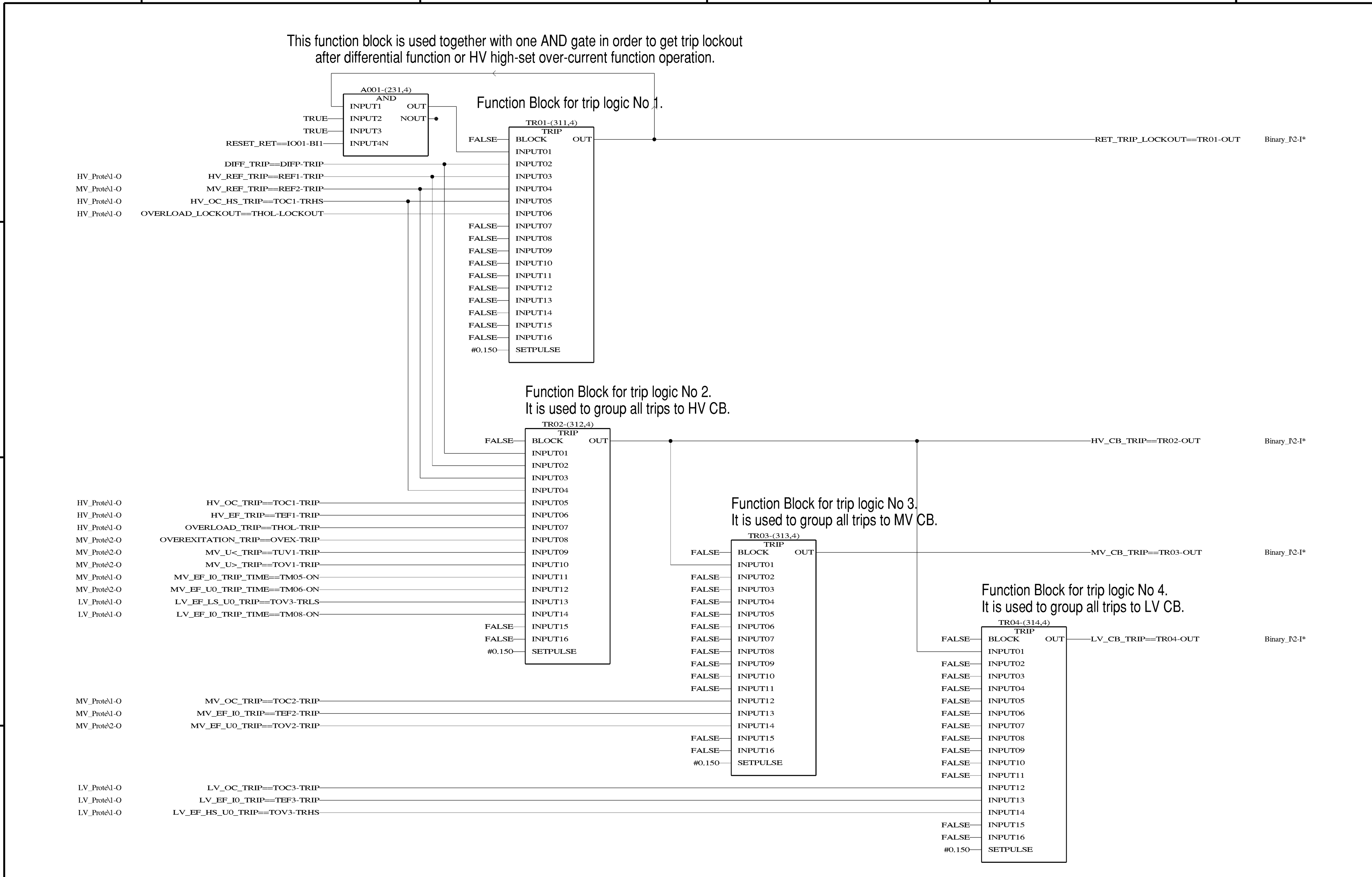


		Prepared	02-04-20	RET521 2p4	MV_Prote
		Approved Birger Hillström	02-04-25		
					Resp dep SA/ATA, Rev Ind
Rev Ind		Reg nr		ABB Autom. Techn. Prod. AB	Example 5, Sheet 2/2
Based on		Pcl			



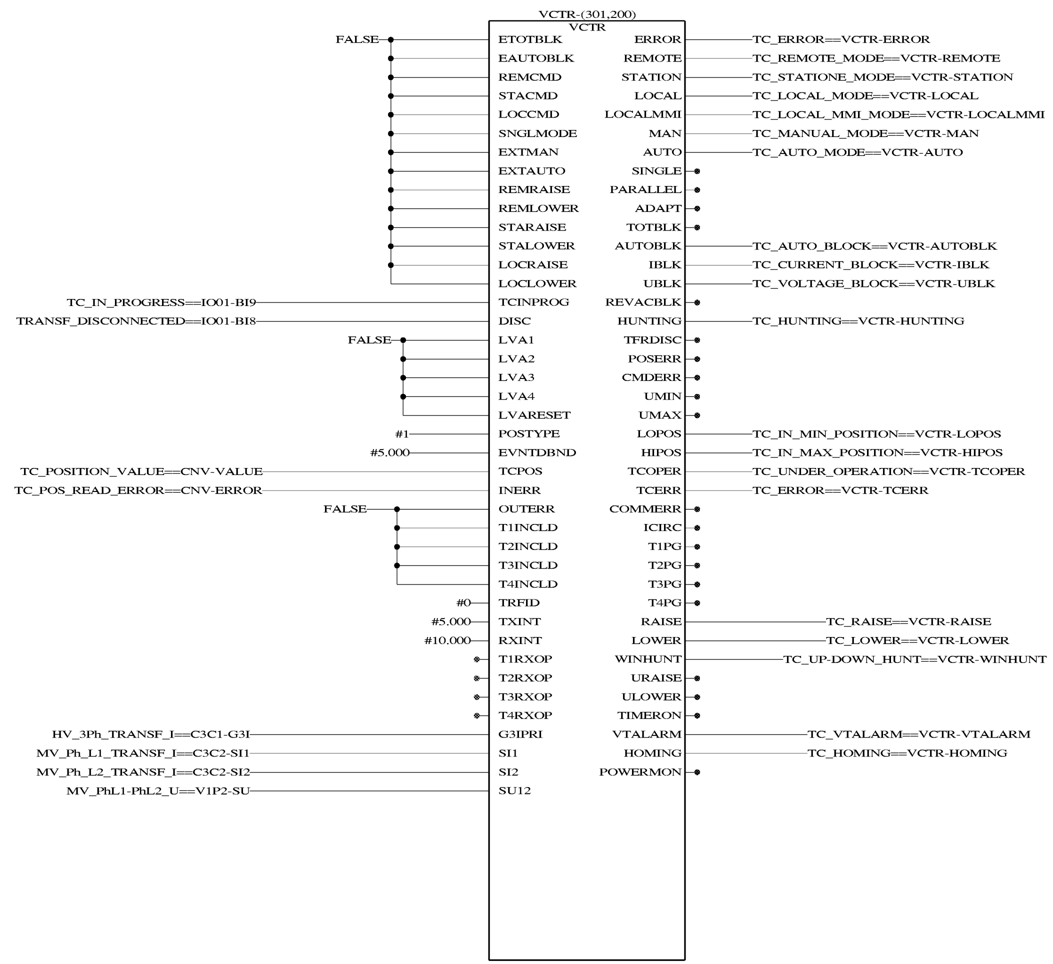
PLEASE NOTE that on all LV protection functions parameter SIDE3W must be set to value 3 in order to indicate to the respective function that it is connected to the LV (i.e. tertiary) side of the power transformer.

Prepared		02-04-20	RET521 2p4		LV_Prote
Approved	Birger Hillström	02-04-25		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 5	Sheet 1/1
Based on	Pcl				



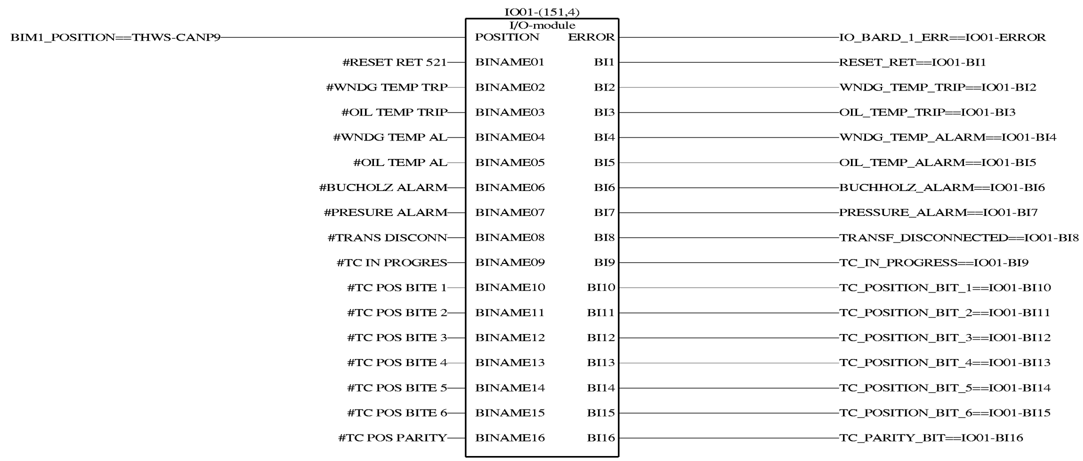
		Prepared	02-04-20	RET521 2p4	Trip_Log
		Approved Birger Hillström	02-04-25		
					Resp dep SA/ATA Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 5 Sheet 1/1
Based on	Pcl				

Function Block for MV side voltage control function (i.e. tap changer control function).
VCTR parallell for maximum 4 parallel operating transformers



		Prepared	02-04-20	RET521 2p4	Voltage_
		Approved Birger Hillström	02-04-25		
					Resp dep SA/ATA Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 5	Sheet 1/1
Based on	Pcl				

Function Block for Binary Input Module (BIM) with 16 optocoupler inputs.

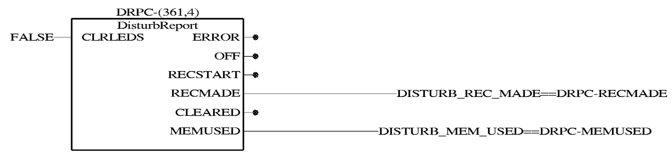


		Prepared	02-04-20	RET521 2p4		Binary_I
		Approved Birger Hillström	02-04-25			
					Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 5	Sheet 1/2
Based on	Pcl					

Function Block for Binary Output Module (BOM) with 24 contact outputs.

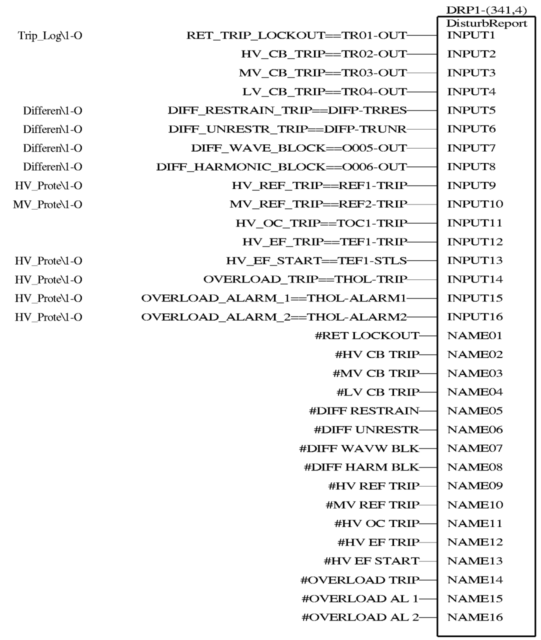
		Prepared	02-04-20	RET521 2p4	Binary_I
		Approved Birger Hillström	02-04-25		
					Resp dep SA/ATA Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 5 Sheet 2/2
Based on	Pcl				

Function Block for Disturbance Report function.
It provides binary indication when new recording is made and when avaiable memory is used.

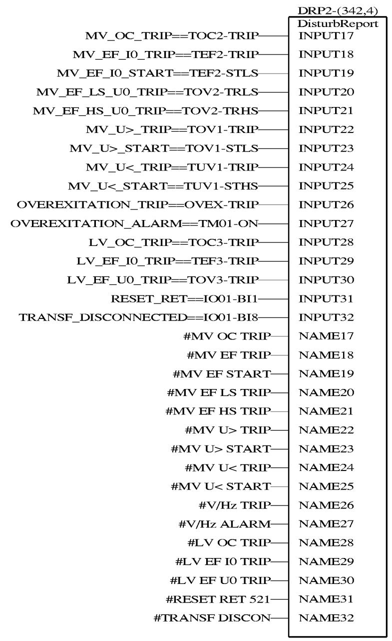


Prepared		02-04-20	RET521 2p4	Disturba
Approved	Birger Hillström	02-04-25		
Rev Ind	Reg nr		Resp dep SA/ATA	Rev Ind
Based on	Pcl		ABB Autom. Techn. Prod. AB	Example 5	Sheet 1/2

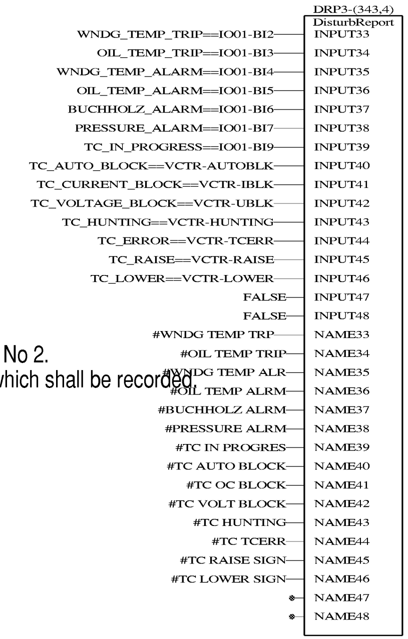
Function Block for Disturbance Report function No 1.
It is possible to connect first lot of 16 binary signals which shall be recorded.



Function Block for Disturbance Report function No 2.
It is possible to connect second lot of 16 binary signals which shall be recorded.



Function Block for Disturbance Report function No 3.
It is possible to connect tird lot of 16 binary signals which shall be recorded.



Prepared		02-04-20	RET521 2p4
Approved	Birger Hillström	02-04-25	
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB
Based on	Pcl		

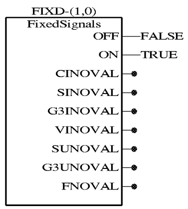
Disturba

Resp dep SA/ATA Rev Ind

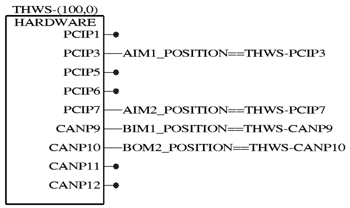
Example 5

Sheet 2/2

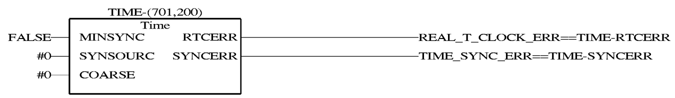
Function Block for fixed signals.
It defines binary zero (i.e. FALSE) and binary one (i.e. TRUE) values.



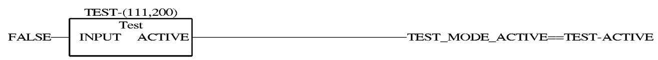
Function Block for terminal hardware structure.
It defines internal positions of all ordered hardware modules.
(i.e. AIM1, BIM1, BOM1 & MIM in this configuration)



Function Block for synchronization of terminal internal real time clock.



Function Block for terminal "Test Mode"

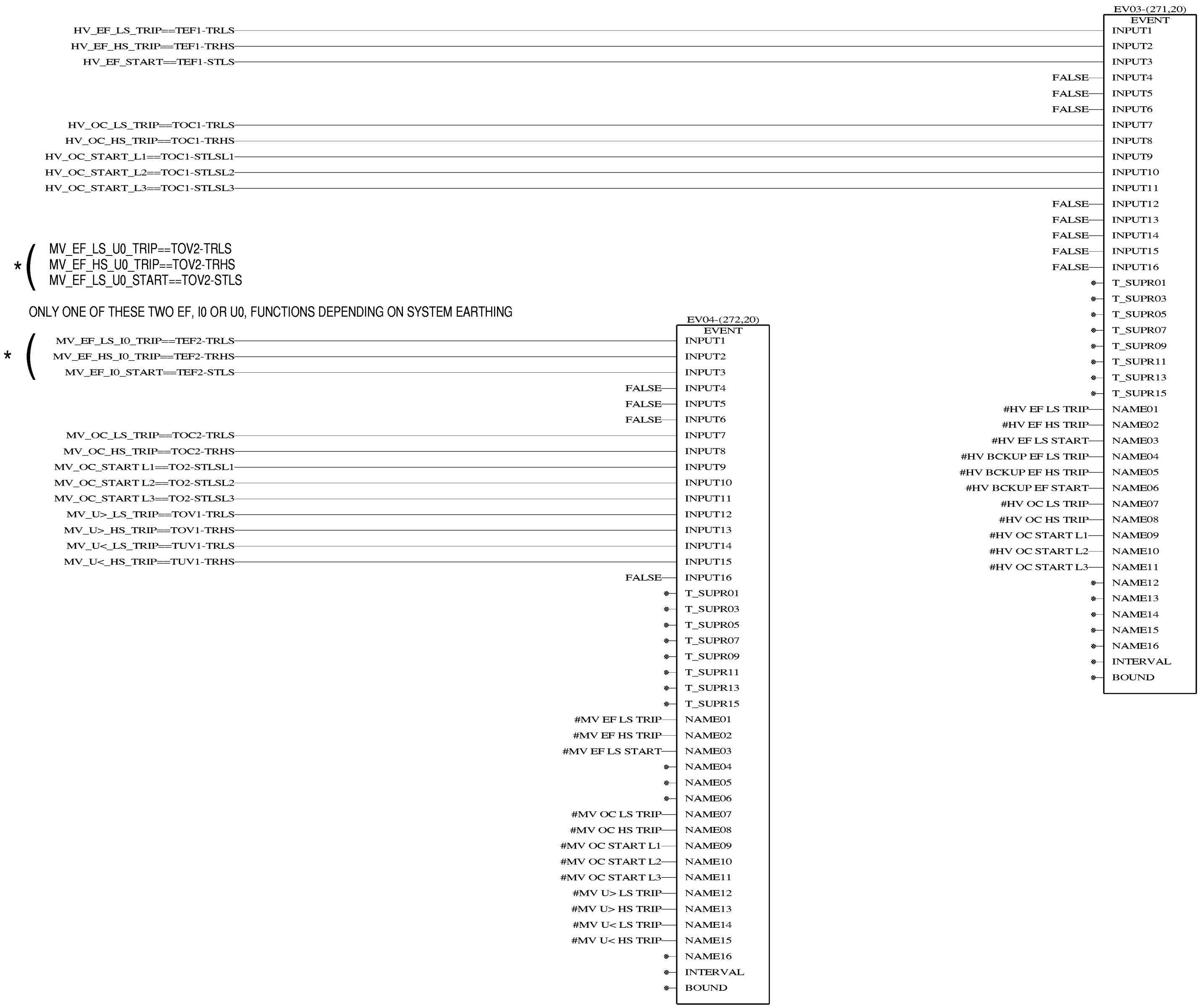


Prepared	02-04-20	RET521 2p4		Subsidar
Approved Birger Hillström	02-04-25			
Rev Ind	Reg nr		Resp dep SA/ATA	Rev Ind
Based on	Pcl	ABB Autom. Techn. Prod. AB	Example 5	Sheet 1/1

All EVENT blocks in this worksheet are used to report the selected internal binary signals to Substation Control System via LON bus.

If rear LON port is not ordered or it is not connected to SCS then this worksheet has no meaning.

Prepared	02-04-20	RET521 2p4		Events_v
Approved Birger Hillström	02-04-25		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr	ABB Autom. Techn. Prod. AB	Example 5	Sheet 1/6
Based on	Pcl			



Prepared		02-04-20
Approved	Birger Hillström	02-04-25
Rev Ind	Reg nr	
Based on	Pcl	

RET521 2p4

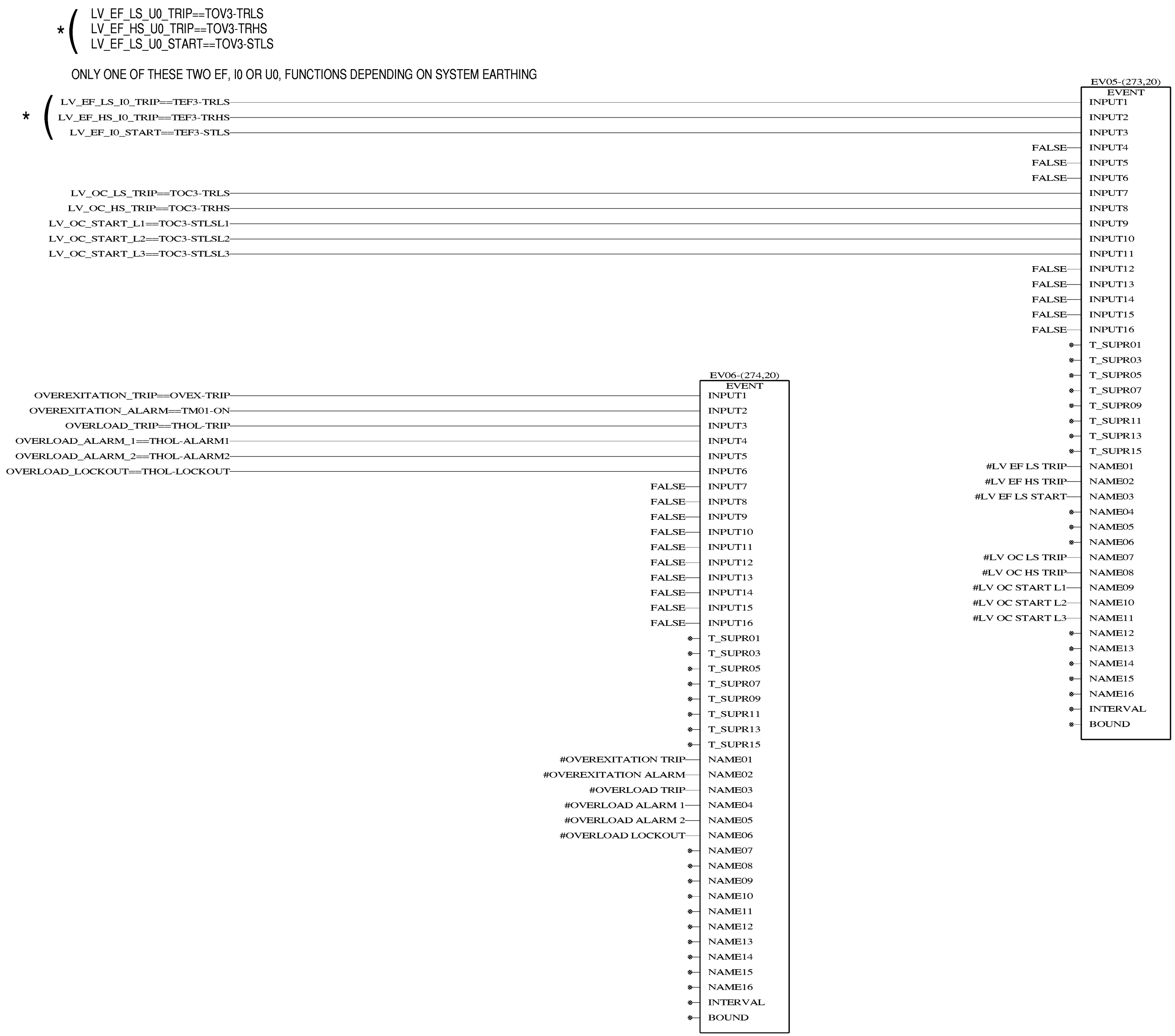
ABB Autom. Techn. Prod. AB

Resp dep SA/ATA | Rev Ind

Example 5

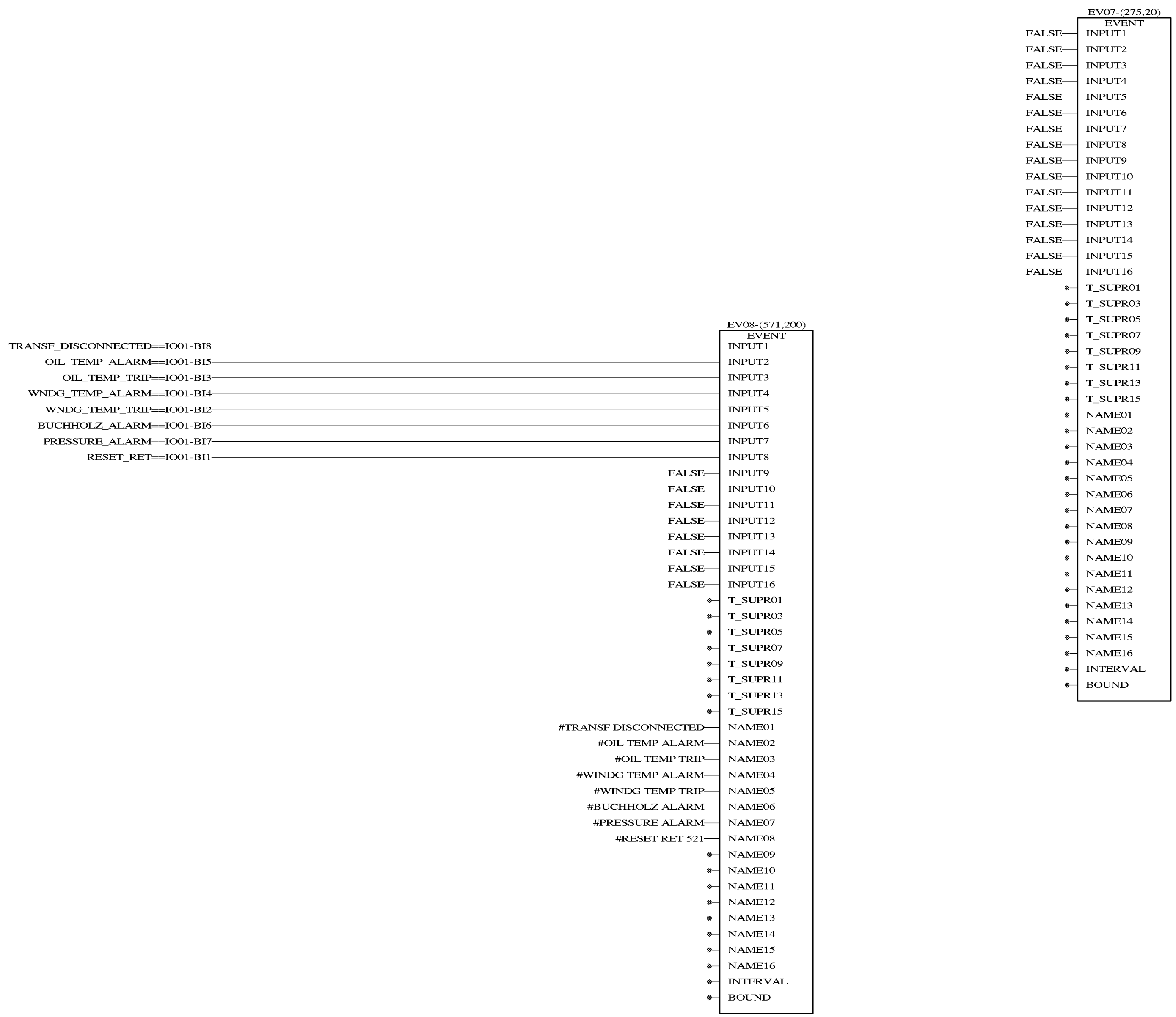
Events_v

Sheet 2/6

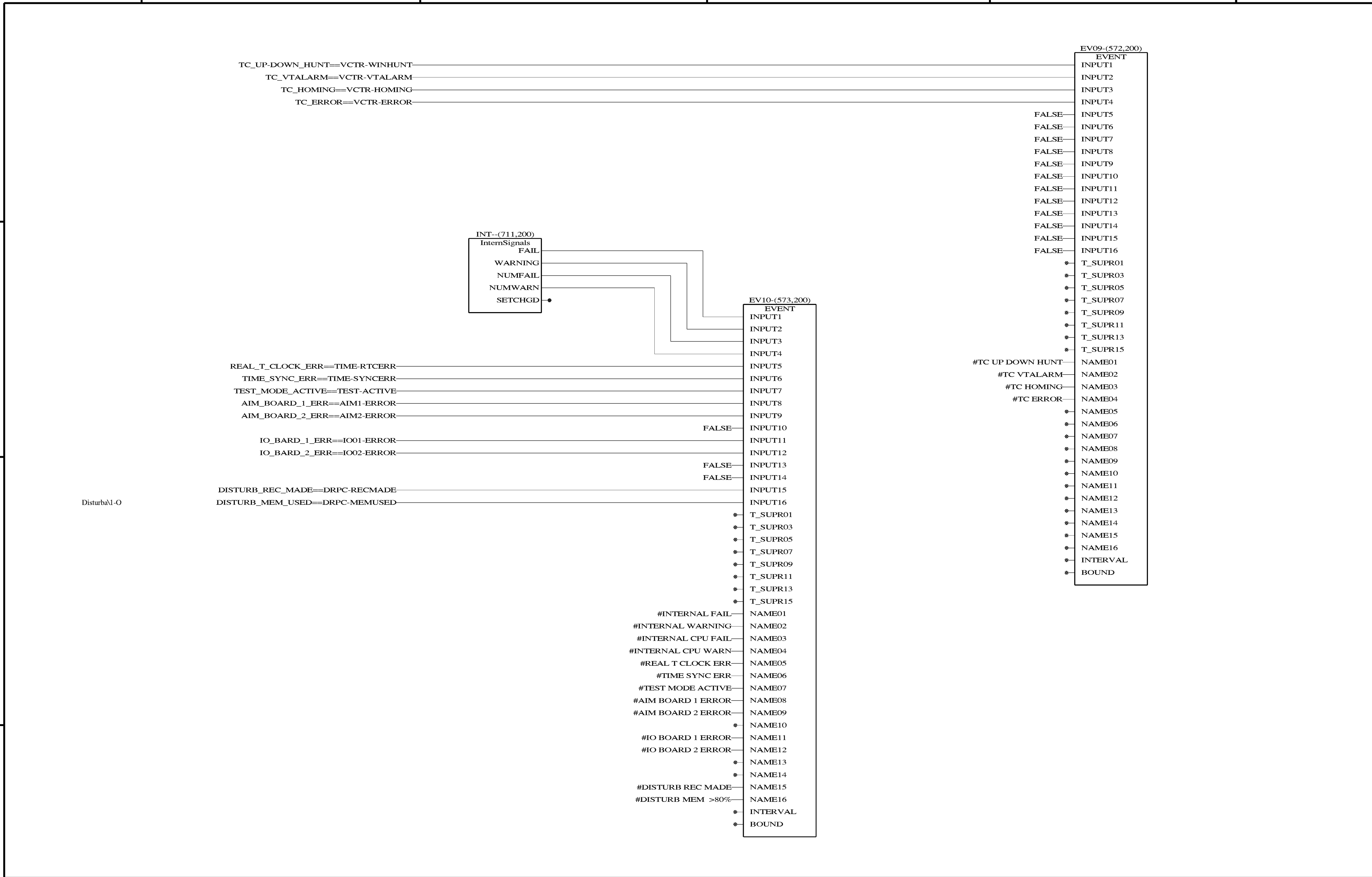


Prepared		02-04-20	RET521 2p4
Approved	Birger Hillström	02-04-25	
Rev Ind	Reg nr	Resp dep SA/ATA	Rev Ind
Based on	Pcl	ABB Autom. Techn. Prod. AB	Example 5
		Events_v	Sheet 3/6

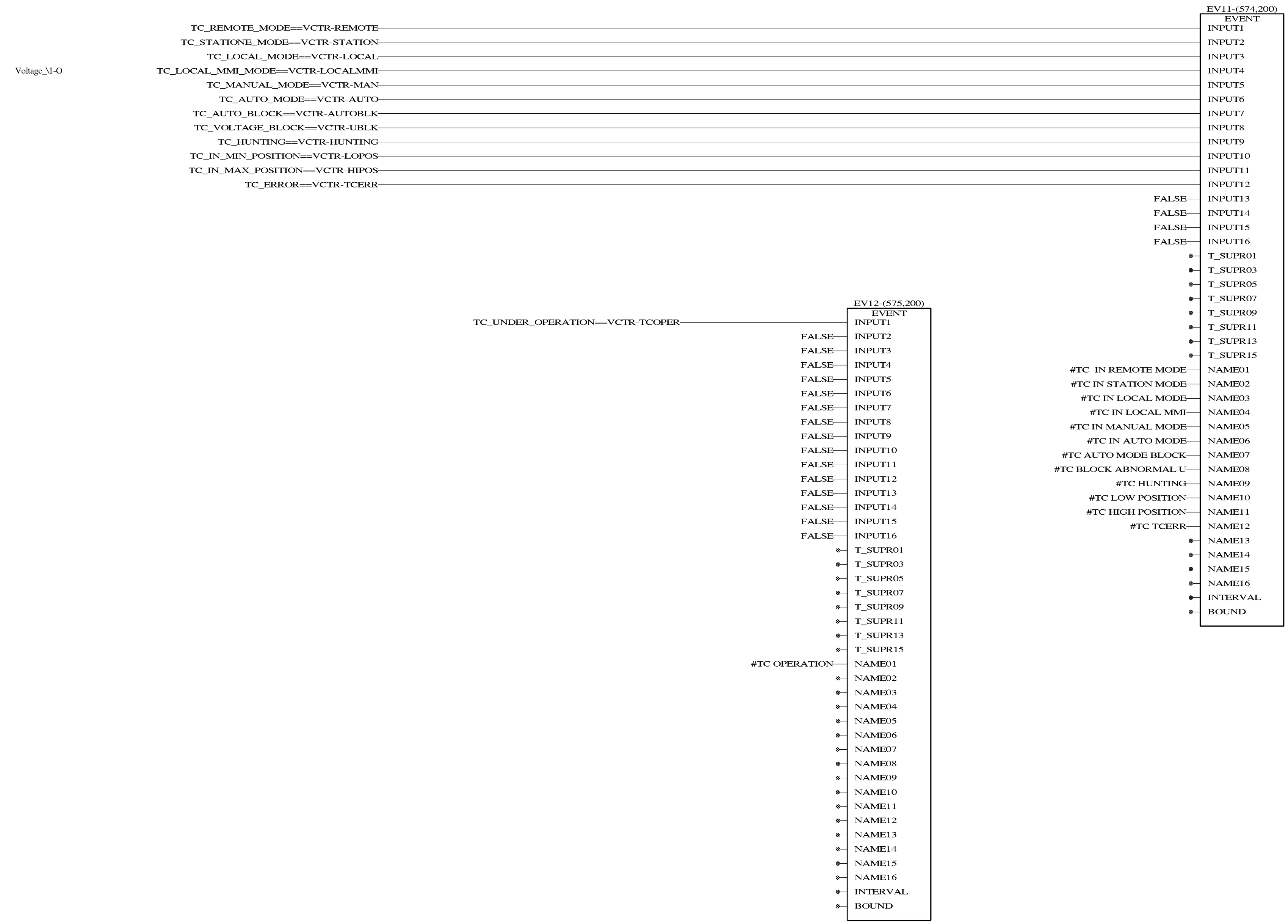
Event block 07 free, preferably used by customer.



Prepared		02-04-20	RET521 2p4	Events_v
Approved	Birger Hillström	02-04-25		
Rev Ind	Reg nr			Resp dep SA/ATA Rev Ind
Based on	Pcl		ABB Autom. Techn. Prod. AB	Example 5 Sheet 4/6



Prepared	02-04-20	RET521 2p4	Events_v
Approved Birger Hillström	02-04-25		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr	ABB Autom. Techn. Prod. AB	Example 5	Sheet 5/6
Based on	Pcl			



		Prepared	02-04-20	RET521 2p4	Events_v
		Approved Birger Hillström	02-04-25		
Rev Ind	Reg nr			Resp dep SA/ATA	Rev Ind
Based on	Pcl			ABB Autom. Techn. Prod. AB	Example 5	Sheet 6/6

Description Example Config no 6 (1MRK 001 536-27)	Work Sheet No
List of Content	Sheet No 01
Short Configuration Description	Sheet No 02
Configuration of Current & Voltage Signals	Sheet No 03
Reading of Tap Position via mA input signal	Sheet No 04
Differential Protection Function	Sheet No 05
HV Protection Functions	Sheet No 06
MV Protection Functions	Sheet No 07 & 08
LV Protection Functions	Sheet No 09
Tripping Logic	Sheet No 10 & 11
Voltage Control Function	Sheet No 12
Configuration of Binary Input Module	Sheet No 13
Configuration of Binary Output Module	Sheet No 14
Configuration of Disturbance Report	Sheet No 15, 16 & 17
Subsidary Configuration	Sheet No 18 & 19
Configuration of Event Reporting via LON bus	Sheet No 20 to 25

Short configuration description

The example configuration No 6 is made for protection and control of a three winding power transformer.
In the RET 521 terminal the following hardware modules are included: one AIM (9I+1U), one BIM, one BOM & one MIM.
It is assumed that 3-Ph HV currents are connected to analogue inputs 1, 2 & 3; that 3-Ph MV currents are connected to analogue inputs 4, 5 & 6; and that 3-Ph LV currents are connected to analogue inputs 7, 8 & 9.
To the analogue inputs 10 one MV phase-to-phase voltage (UL1-L2) is connected.

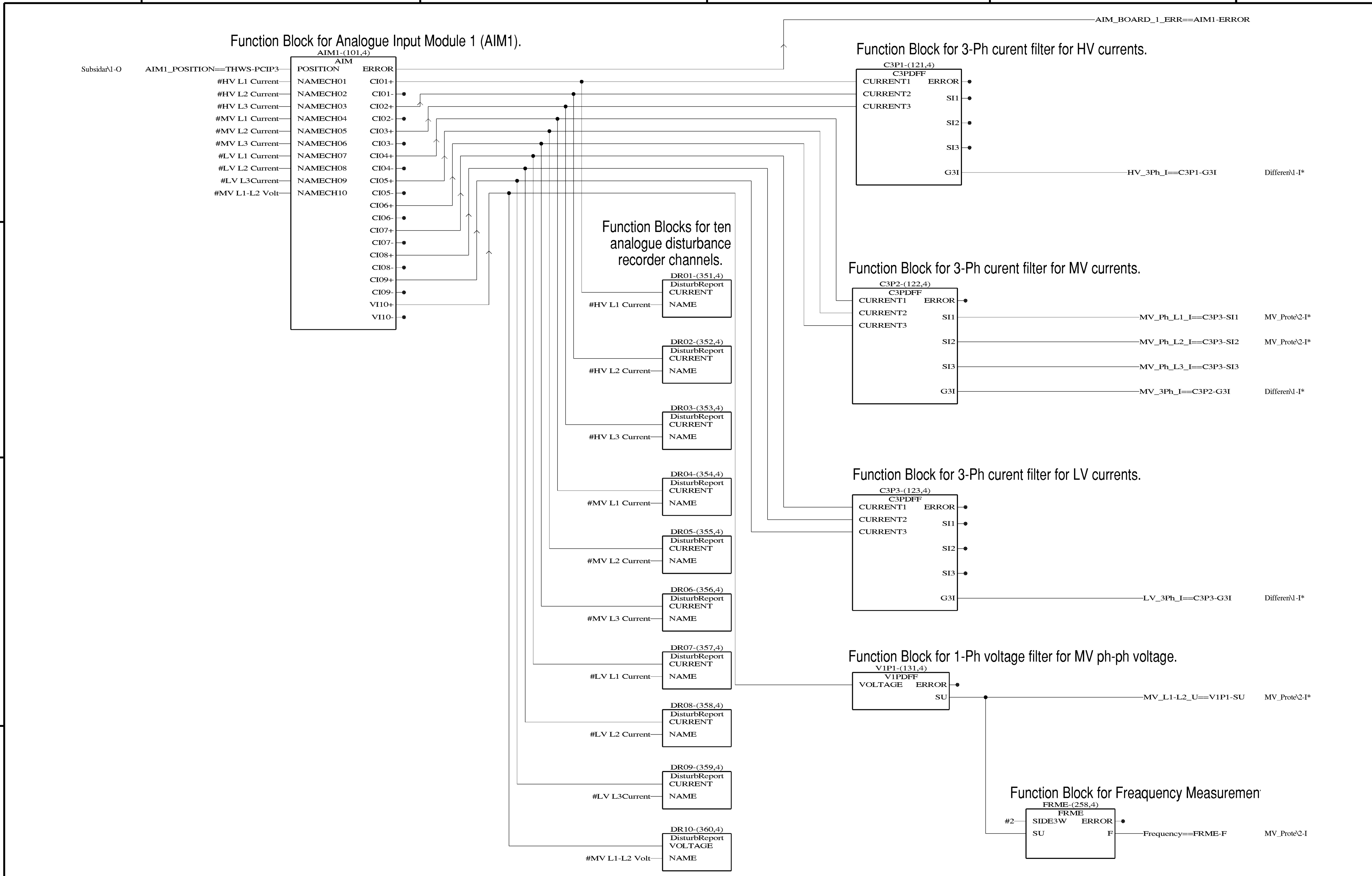
The tap changer with 17 positions is located on the HV winding. Its position is monitored via 4-20mA analogue signal.

The following protection and control function are included in the configuration:

Transformer bias differential protection (87T & 87H); HV 3-Ph OC protection (50, 51); HV EF protection (50N, 51N); MV 3-Ph OC protection (50, 51); MV EF protection (50N, 51N); MV thermal overload (49); MV U< protection (27); MV U> protection (59); Overexcitation protection (24); LV 3-Ph OC protection (50, 51); LV EF protection (50N, 51N) and MV side voltage control (90).
Individual tripping logic for CBs on all three transformer sides are provided.

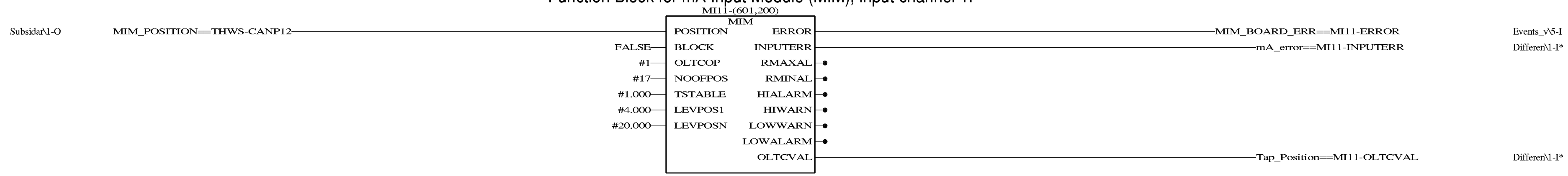
All 10 analogue input signals are connected to the disturbance recorder. In addition to that 48 binary signals are connected to the disturbance recorder as well.
All required inputs and outputs from/to tap changer mechanism are configured.
Finally binary events to the substation control system which will be automatically reported via LON bus are configured.

Rev Ind	Reg nr	Prepared 02-04-15	RET521 2p4	Resp dep SA/ATA	Rev Ind
Based on	Pcl	Approved Birger Hillström 02-04-20	ABB Autom. Techn. Prod. AB	Example 6	Overall_ Sheet 2/2



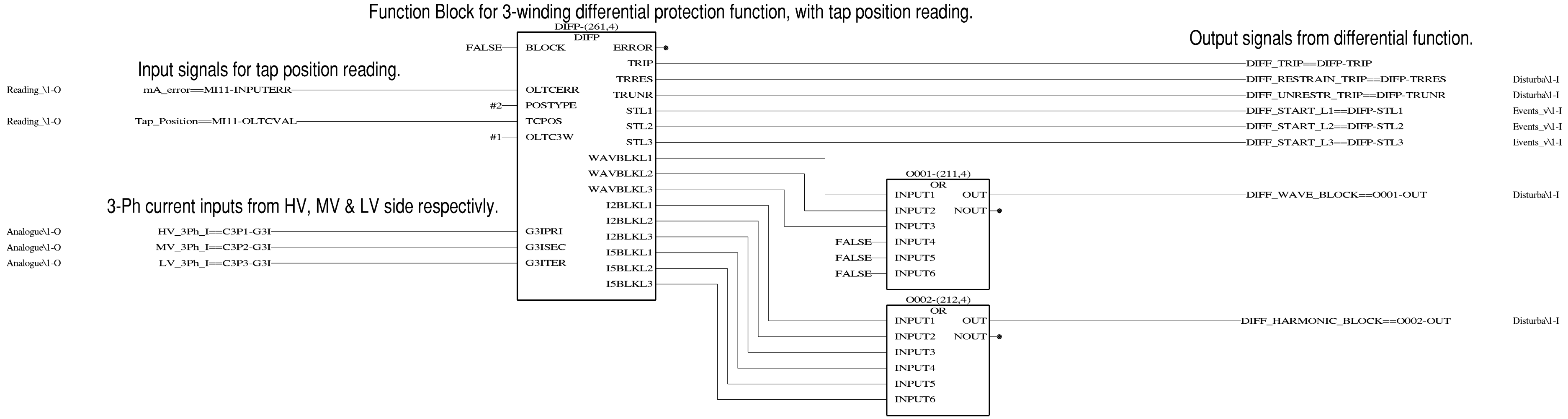
		Prepared	02-04-15	RET521 2p4	Analogue
		Approved Birger Hillström	02-04-20		Resp dep SA/ATA · Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 6 · Sheet 1/1
Based on	Pcl				

Function Block for mA Input Module (MIM), input channel 1.

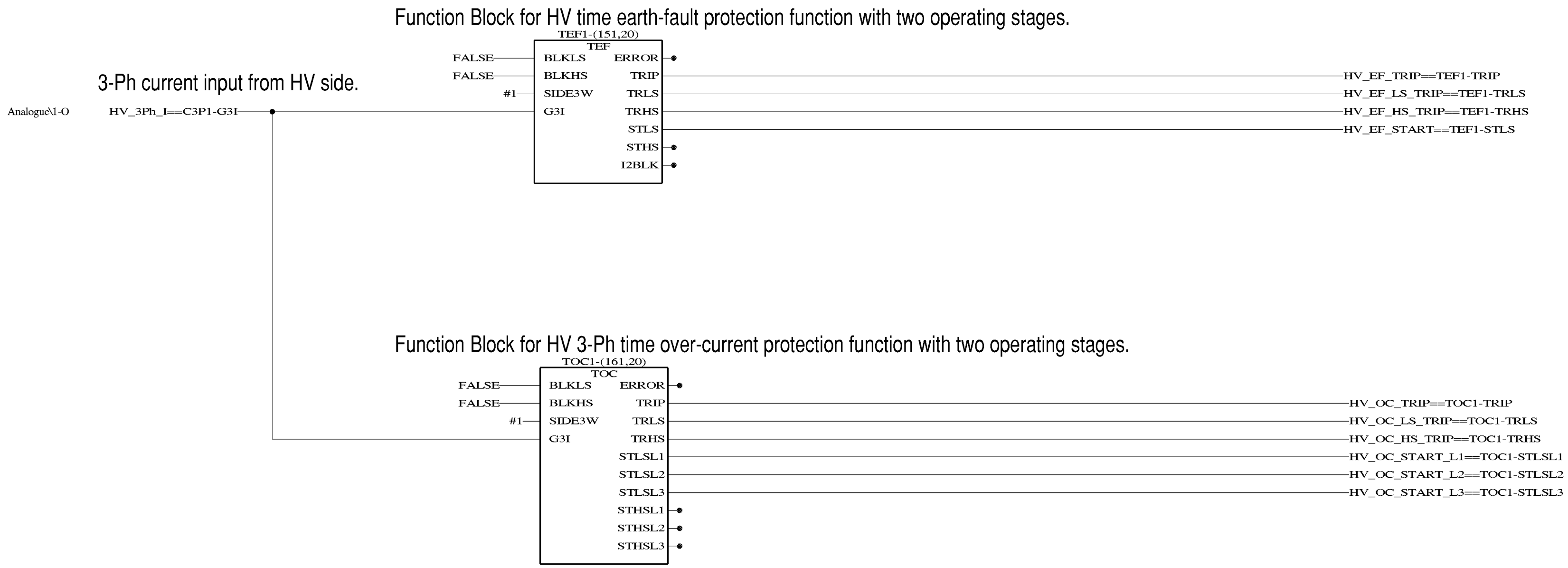


This function block is used here to convert 4-20mA input signal into 17 tap positions.
Value of tap position is then given to differential protection function and
voltage control function in order to enhance their functionality.

Prepared		02-04-15	RET521 2p4		Reading_
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 6	Sheet 1/1
Based on	Pcl				

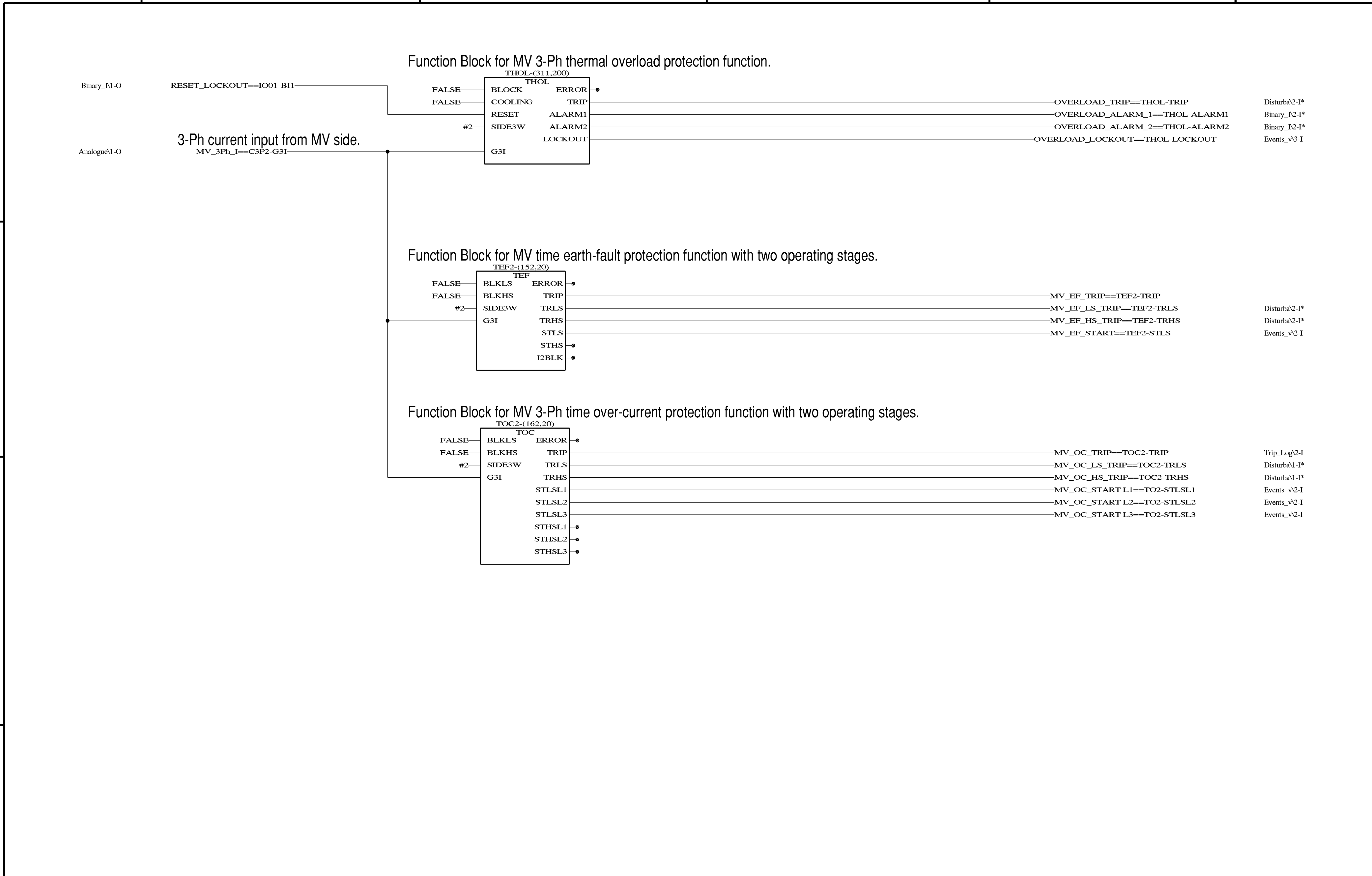


		Prepared	02-04-15	RET521 2p4	Differen
		Approved Birger Hillström	02-04-20		
					Resp dep SA/ATA / Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 6 / Sheet 1/1
Based on	Pcl				

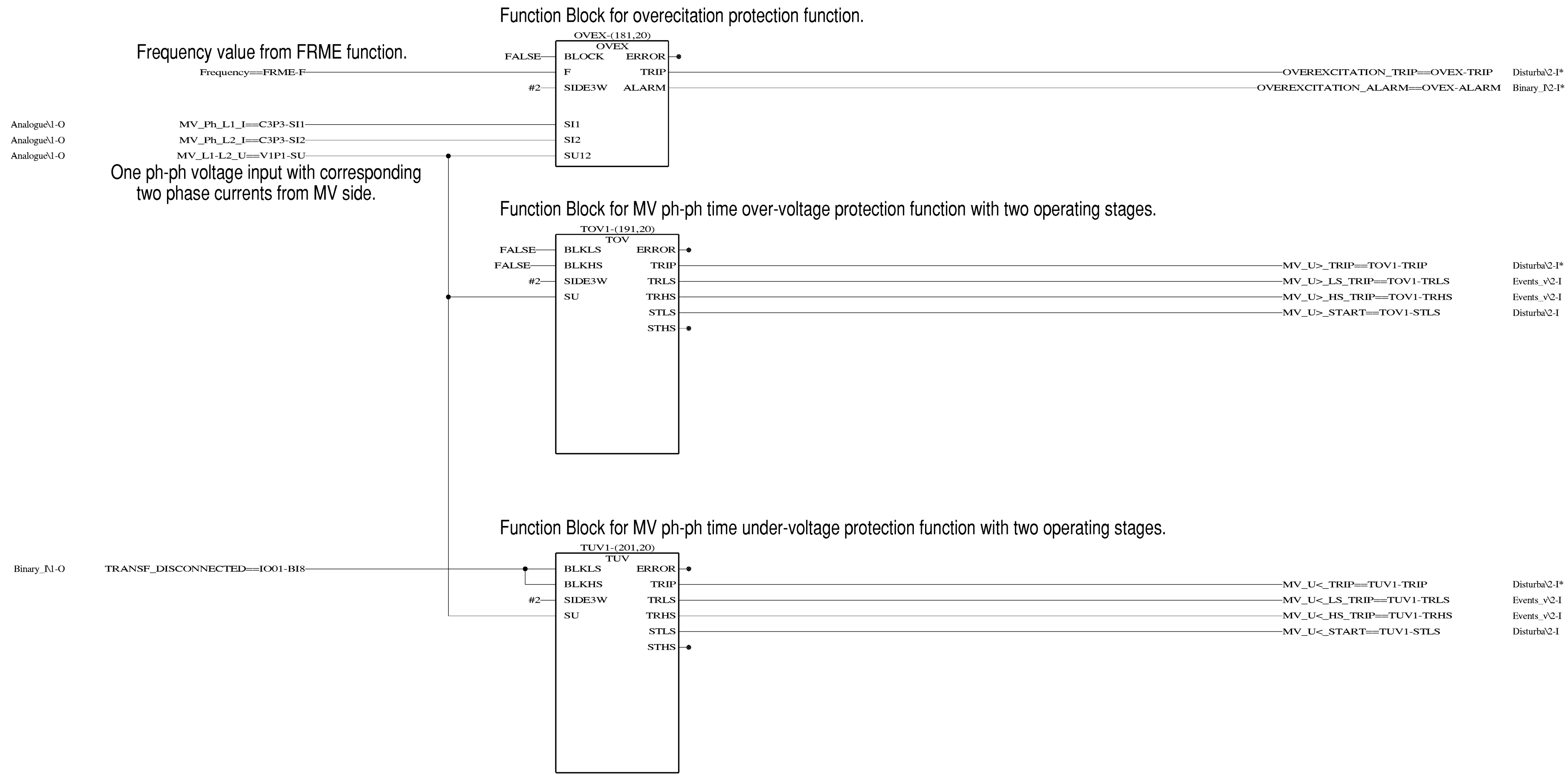


PLEASE NOTE that on all HV protection functions parameter SIDE3W must be set to value 1 in order to indicate to the respective function that it is connected to the HV (i.e. primary) side of the power transformer.

Prepared		02-04-15	RET521 2p4	HV_Prote
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA · Rev Ind
Rev Ind	Reg nr		ABB Autom. Techn. Prod. AB	Example 6 · Sheet 1/1
Based on	Pcl			

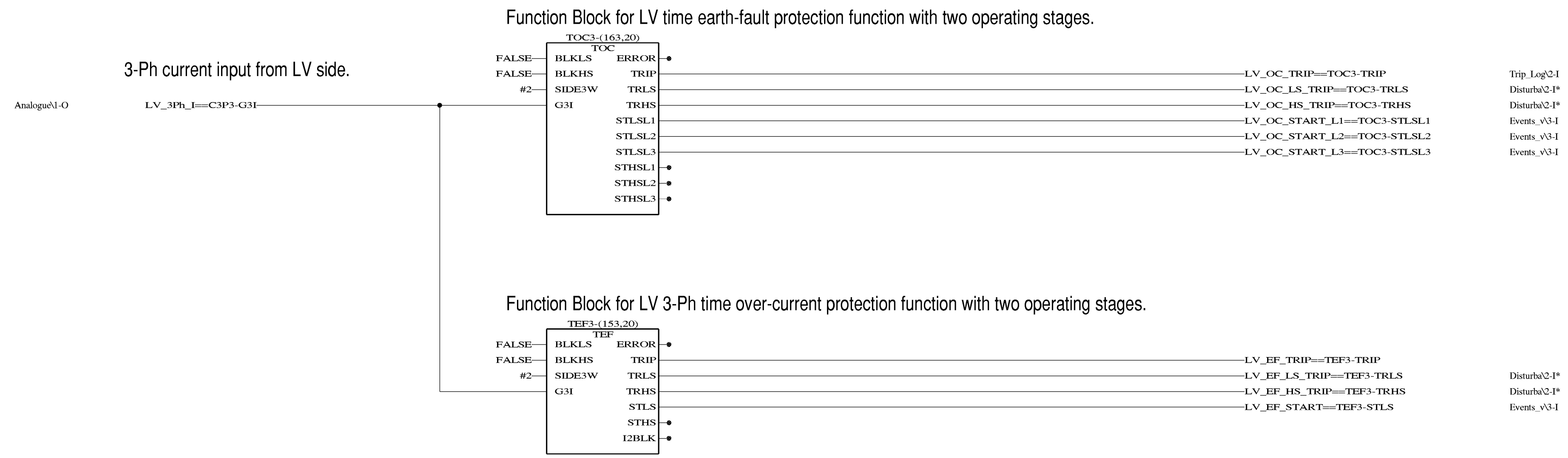


Rev Ind	Reg nr	Prepared	02-04-15	RET521 2p4
Based on	Pcl	Approved Birger Hillström	02-04-20	ABB Autom. Techn. Prod. AB
Resp dep	SA/ATA	Rev Ind		MV_Prote
Example 6		Sheet 1/2		



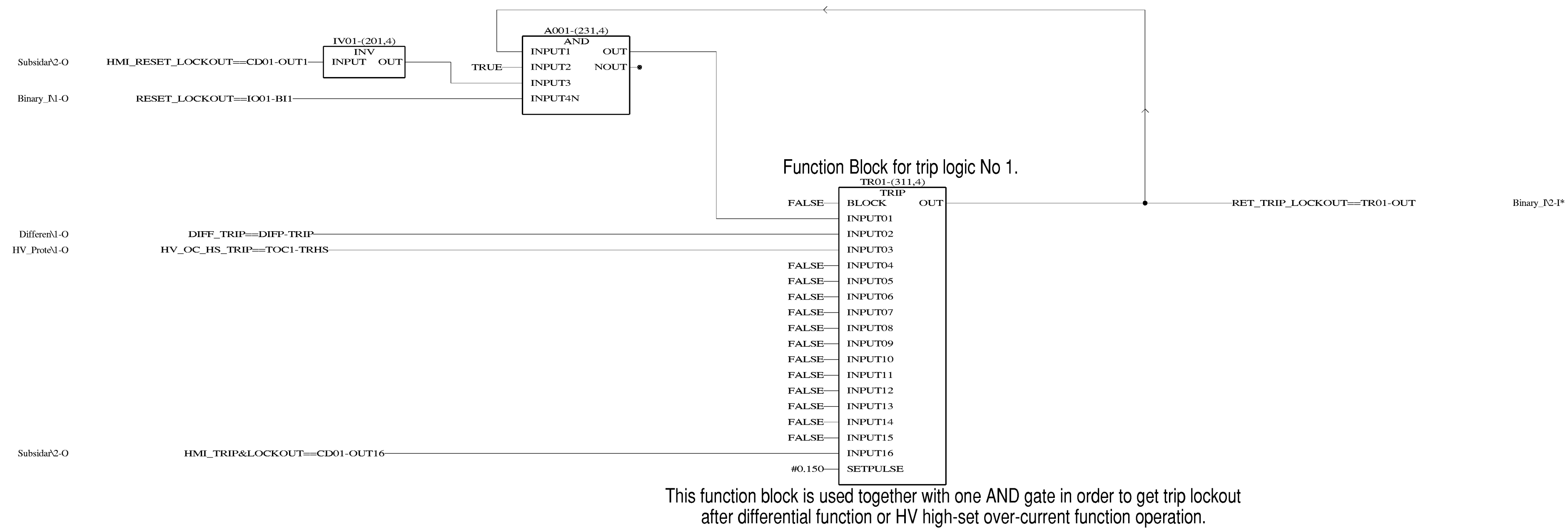
PLEASE NOTE that on all MV protection functions parameter SIDE3W must be set to value 2 in order to indicate to the respective function that it is connected to the MV (i.e. secondary) side of the power transformer.

Prepared		02-04-15	RET521 2p4	MV_Prote
Approved	Birger Hillström	02-04-20		
Rev Ind	Reg nr		Resp dep SA/ATA	Rev Ind
Based on	Pcl		ABB Autom. Techn. Prod. AB	Example 6	Sheet 2/2

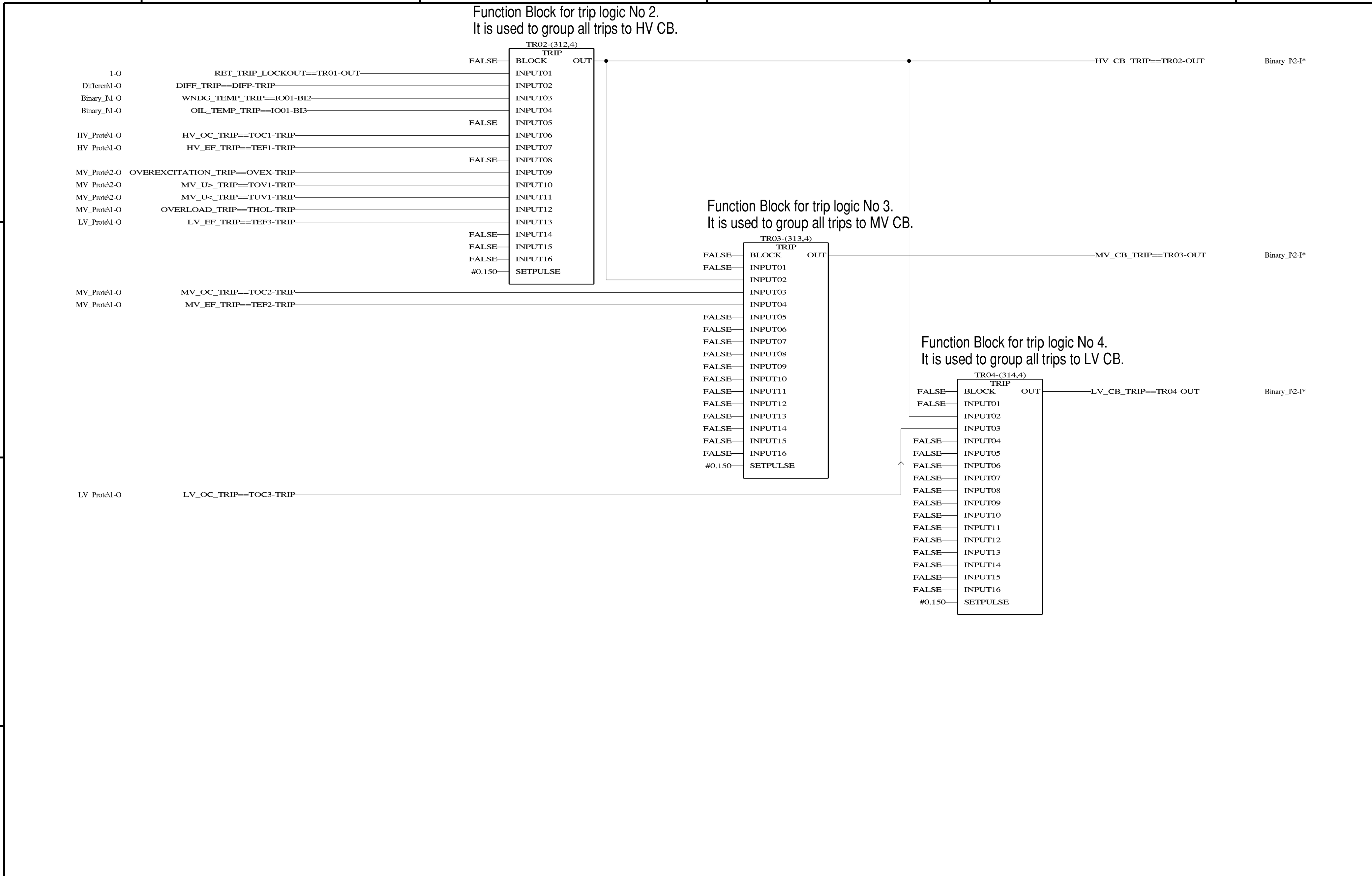


PLEASE NOTE that on all LV protection functions parameter SIDE3W must be set to value 3 in order to indicate to the respective function that it is connected to the LV (i.e. tertiary) side of the power transformer.

Prepared	02-04-15	RET521 2p4	LV_Prote
Approved Birger Hillström	02-04-20		
Rev Ind / Reg nr		Resp dep SA/ATA	Rev Ind
Based on / Pcl		ABB Autom. Techn. Prod. AB	Example 6 / Sheet 1/1

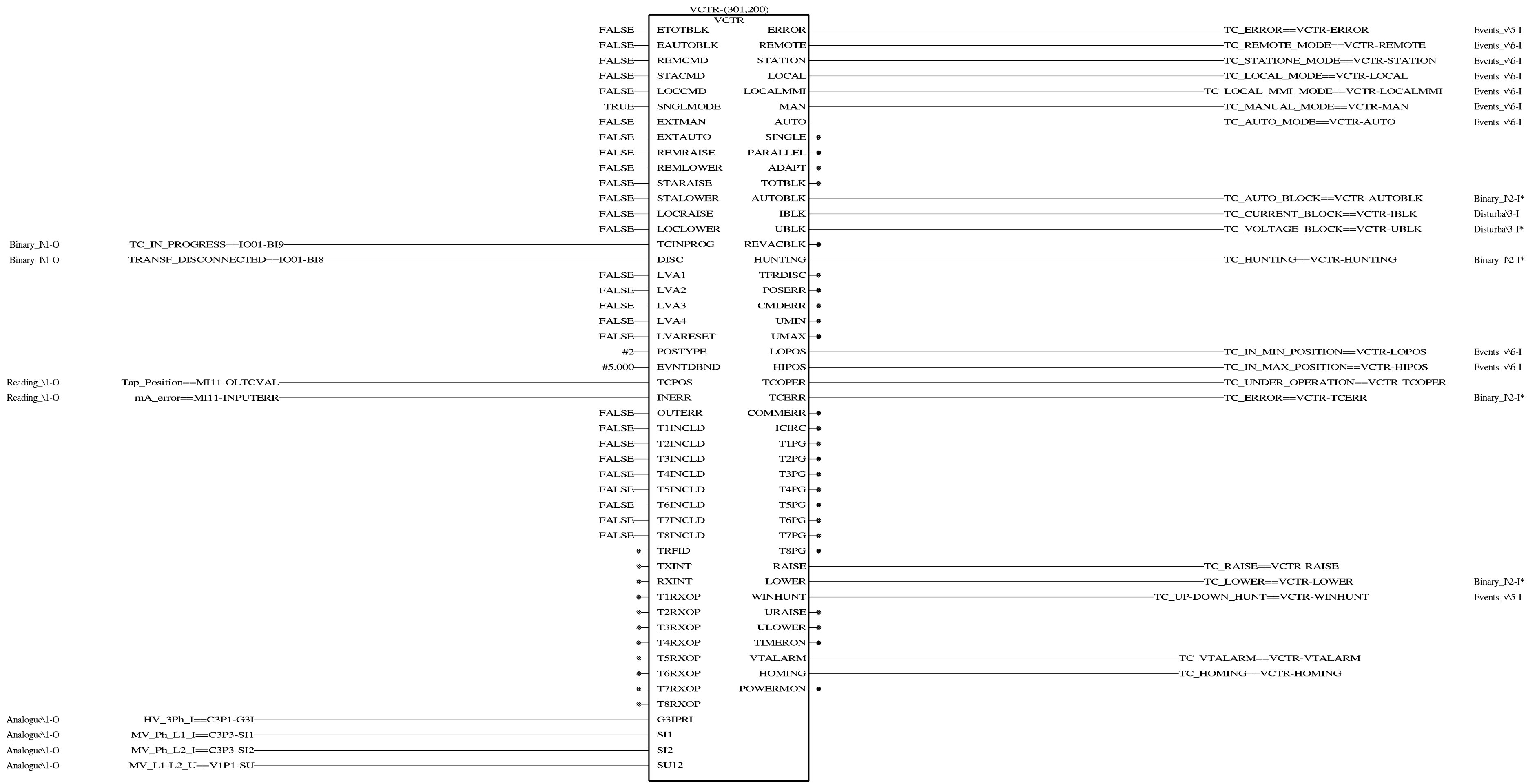


Prepared	02-04-15	RET521 2p4	Trip_Log
Approved Birger Hillström	02-04-20		Resp dep SA/ATA · Rev Ind
Rev Ind · Reg nr		ABB Autom. Techn. Prod. AB	Example 6 · Sheet 1/2
Based on · Pcl			



		Prepared	02-04-15	RET521 2p4	Trip_Log
		Approved Birger Hillström	02-04-20		
					Resp dep SA/ATA / Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 6 / Sheet 2/2
Based on	Pcl				

Function Block for MV side voltage control function (i.e. tap changer control function).
VCTR parallel for max 8 parallel operating transformers



Prepared		02-04-15
Approved	Birger Hillström	02-04-20
Rev Ind	Reg nr	
Based on	Pcl	

RET521 2p4

ABB Autom. Techn. Prod. AB

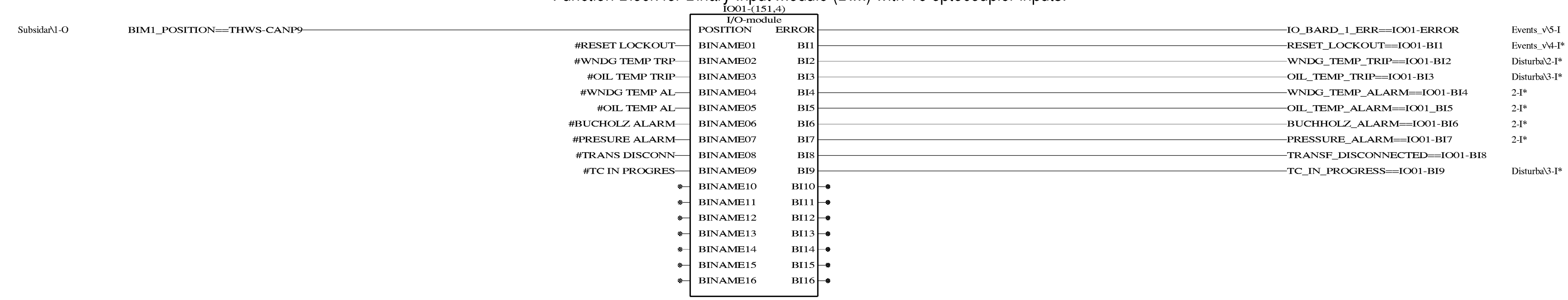
Resp dep SA/ATA | Rev Ind

Example 6

Voltage_

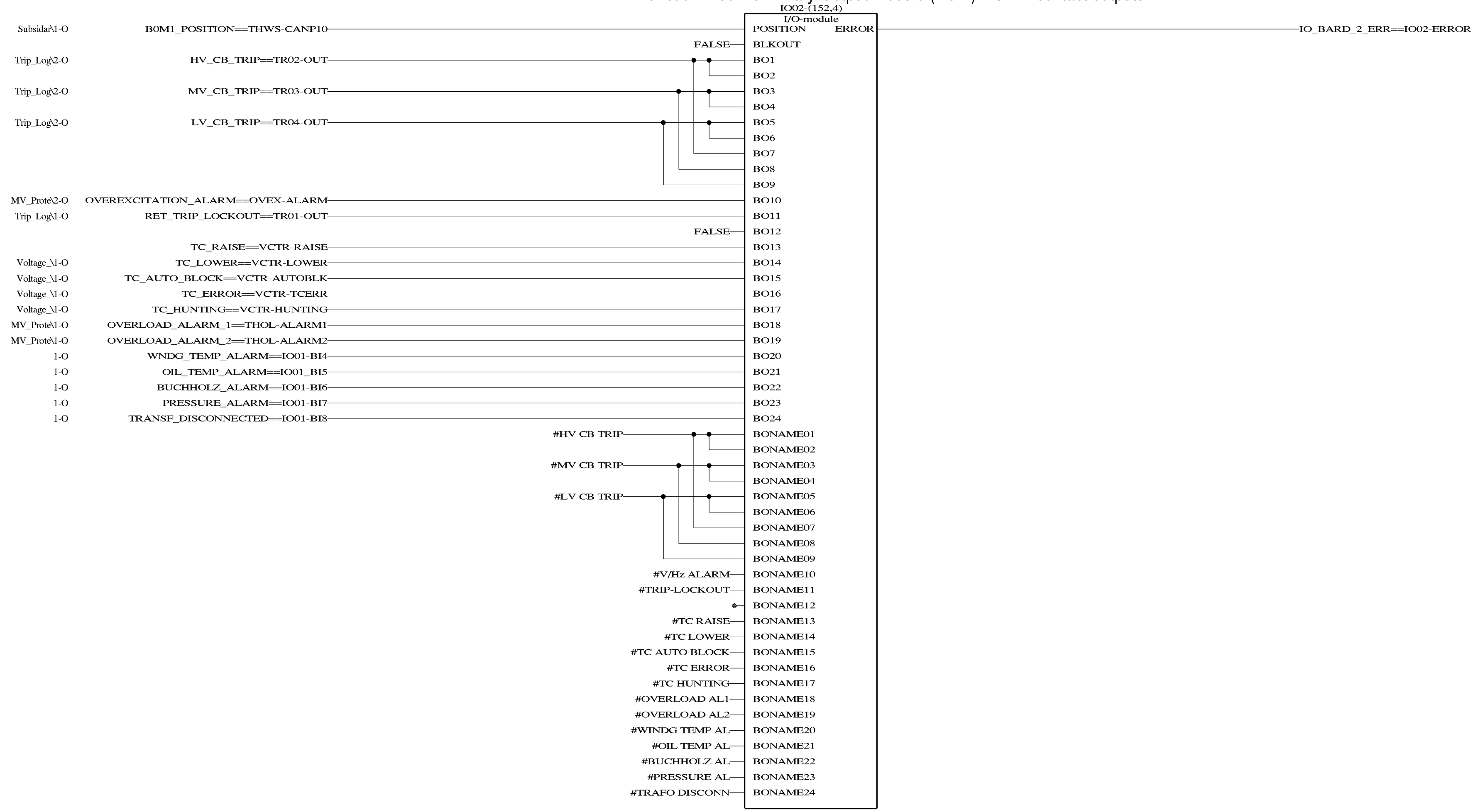
Sheet 1/1

Function Block for Binary Input Module (BIM) with 16 optocoupler inputs.



		Prepared	02-04-15	RET521 2p4	Binary_I
		Approved Birger Hillström	02-04-20		
					Resp dep SA/ATA · Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Example 6 · Sheet 1/2
Based on	Pcl				

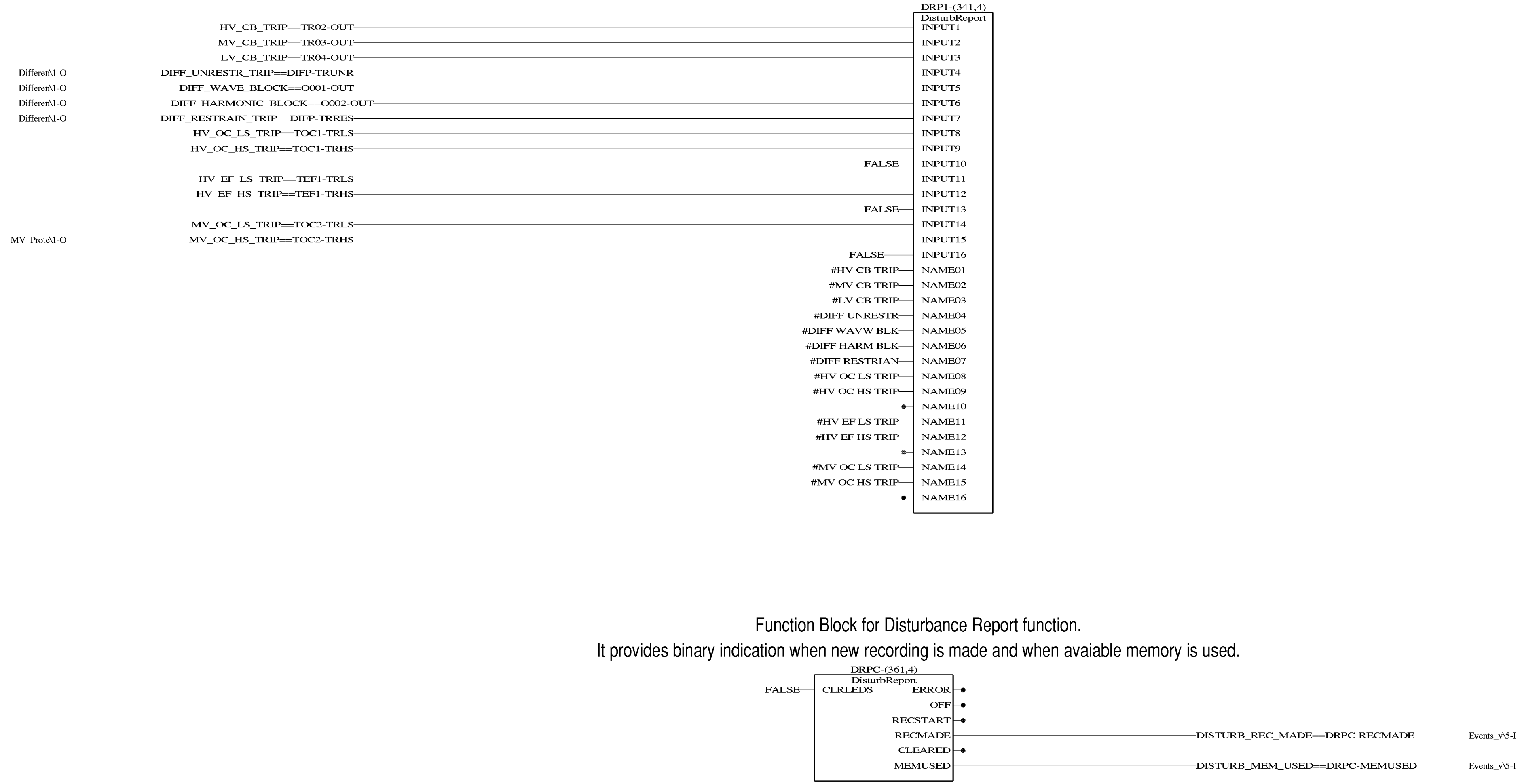
Function Block for Binary Output Module (BOM) with 24 contact outputs.



Prepared		02-04-15	RET521 2p4		Binary_I
Approved	Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind		Reg nr	ABB Autom. Techn. Prod. AB	Example 6	Sheet 2/2
Based on		Pcl			

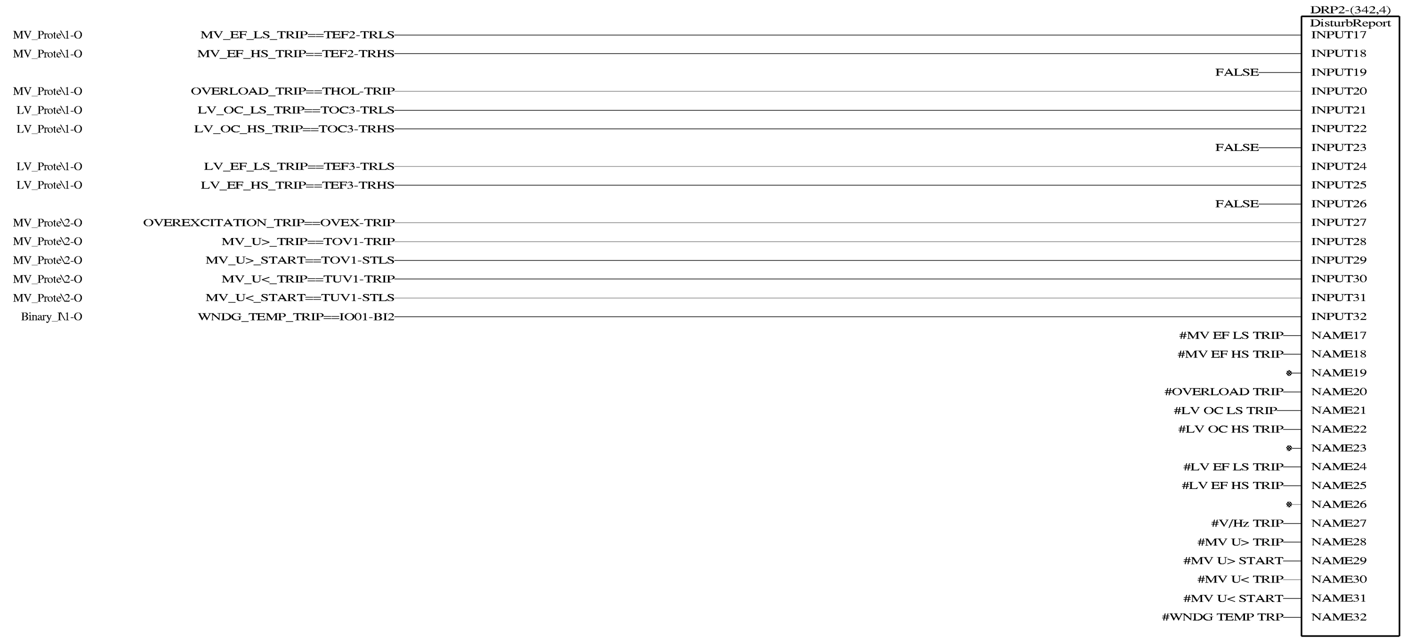
Function Block for Disturbance Report function No 1.
It is possible to connect first lot of 16 binary signals which shall be recorded.

Function Block for Disturbance Report function.
It provides binary indication when new recording is made and when avaiable memory is used.



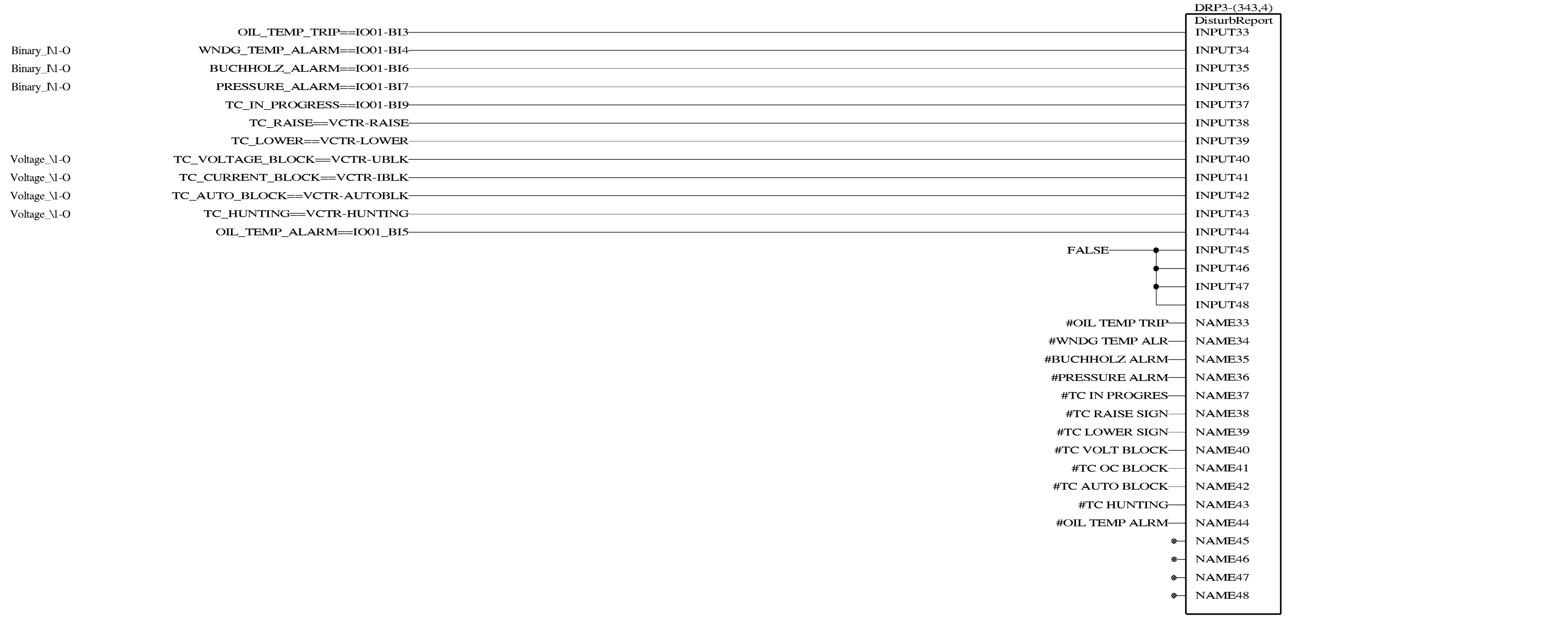
	Prepared		02-04-15	RET521 2p4	Disturba
	Approved	Birger Hillström	02-04-20		
Rev Ind	Reg nr			Resp dep SA/ATA	Rev Ind
Based on	Pcl			ABB Autom. Techn. Prod. AB	Example 6	Sheet 1/3

Function Block for Disturbance Report function No 2.
It is possible to connect second lot of 16 binary signals which shall be recorded.



Prepared 02-04-15
Approved Birger Hillström 02-04-20
RET521 2p4
Disturba
Rev Ind Reg nr
Based on Pcl
Resp dep SA/ATA Rev Ind
ABB Autom. Techn. Prod. AB
Example 6
Sheet 2/3

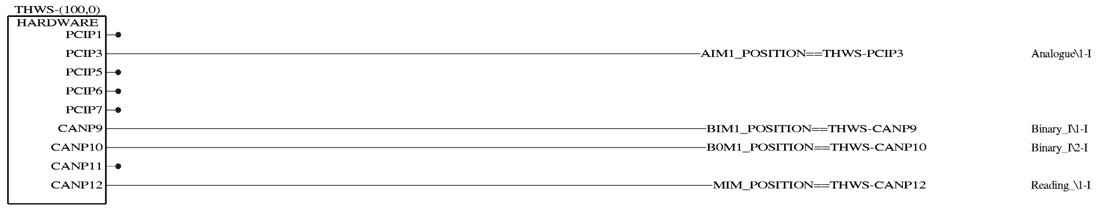
Function Block for Disturbance Report function No 1.
It is possible to connect tird lot of 16 binary signals which shall be recorded.



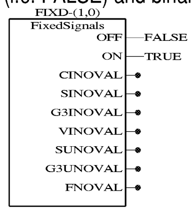
Prepared		02-04-15	RET521 2p4
Approved	Birger Hillström	02-04-20	
Rev Ind	Reg nr		
Based on	Pcl		ABB Autom. Techn. Prod. AB

			Disturba
Resp dep	SA/ATA	Rev Ind	
Example 6			Sheet 3/3

Function Block for terminal hardware structure.
It defines internal positions of all ordered hardware modules.
(i.e. AIM1, BIM1, BOM1 & MIM in this configuration)



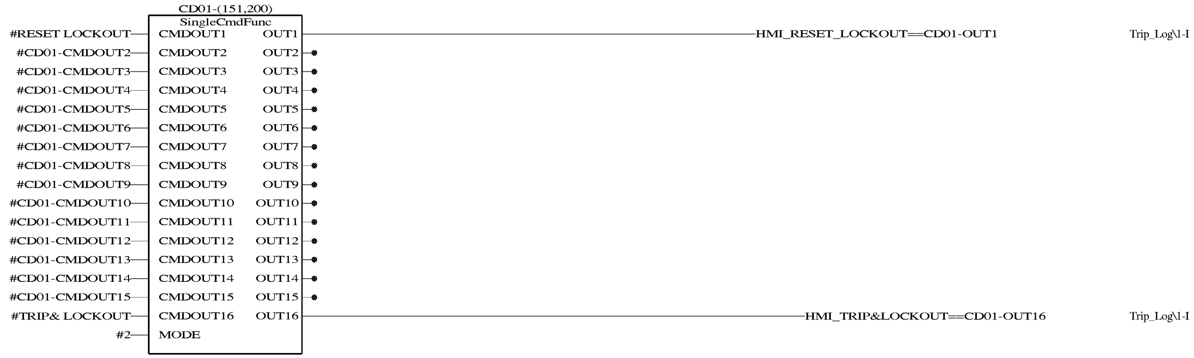
Function Block for fixed signals.
It defines binary zero (i.e. FALSE) and binary one (i.e. TRUE) values.



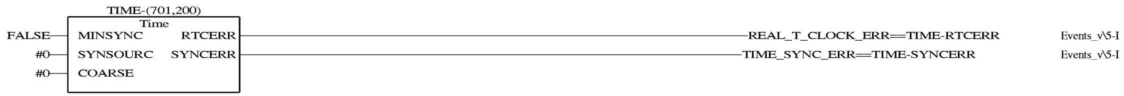
Rev Ind	Reg nr	Prepared	02-04-15	RET521 2p4
Based on	Pcl	Approved Birger Hillström	02-04-20	ABB Autom. Techn. Prod. AB

Resp dep	SA/ATA	Rev Ind	Subsidar
Example 6			Sheet 1/2

Function Block for single command block.
It gives oportunity to issue up to 16 binary commands from built-in HMI.
(Under HMI menu Command/CD01)



Function Block for synchronization of terminal internal real time clock.



Function Block for terminal "Test Mode"

Prepared	02-04-15	RET521 2p4		Subsidar
Approved Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr	ABB Autom. Techn. Prod. AB	Example 6	Sheet 2/2
Based on	Pcl			

All EVENT blocks in this worksheet are used to report the selected internal binary signals to Substation Control System via LON bus.

If rear LON port is not ordered or it is not connected to SCS then this worksheet has no meaning.

Prepared		02-04-15
Approved	Birger Hillström	02-04-20
Rev Ind	Reg nr	
Based on	Pcl	

RET521 2p4

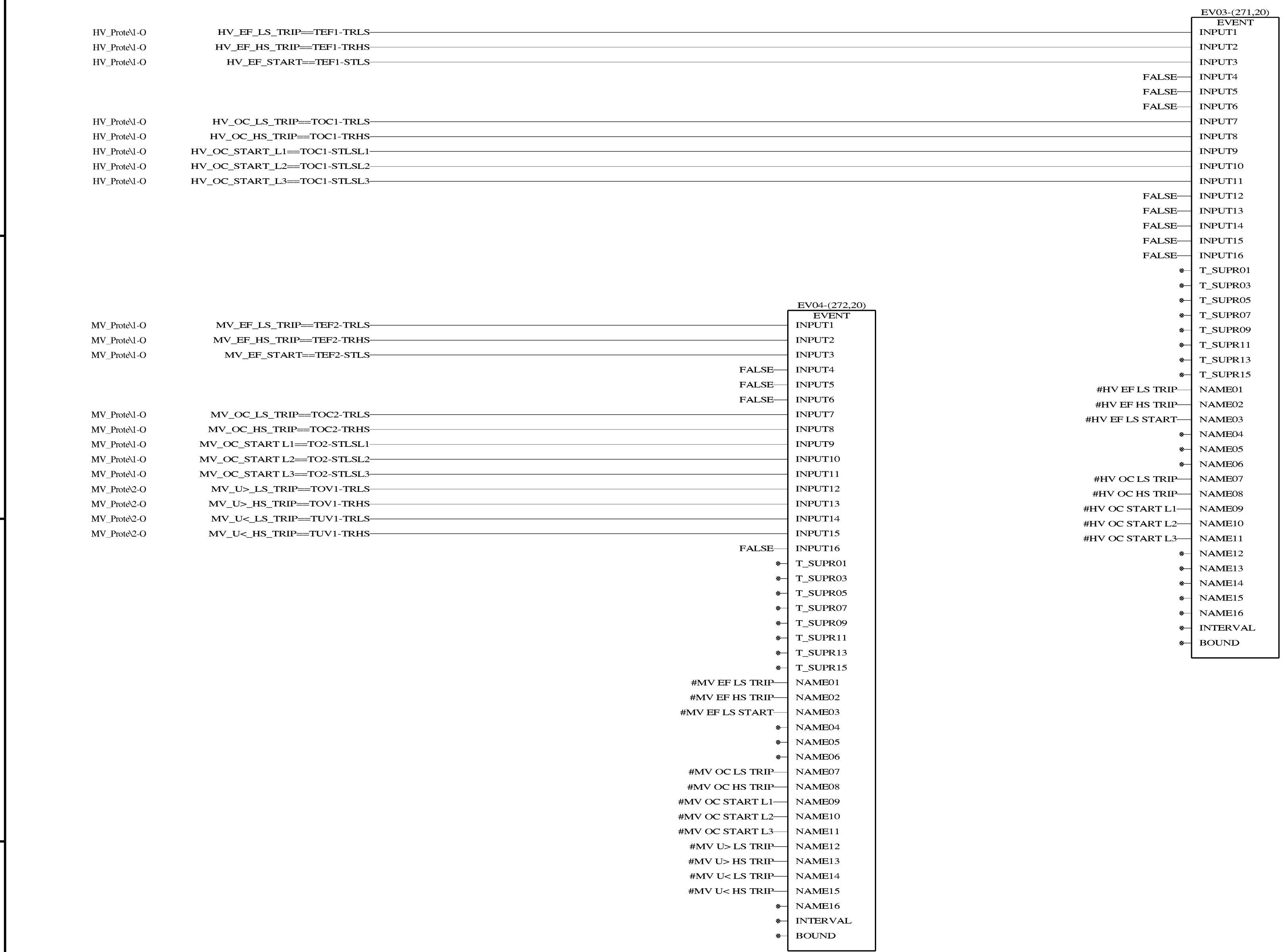
ABB Autom. Techn. Prod. AB

Resp dep SA/ATA | Rev Ind

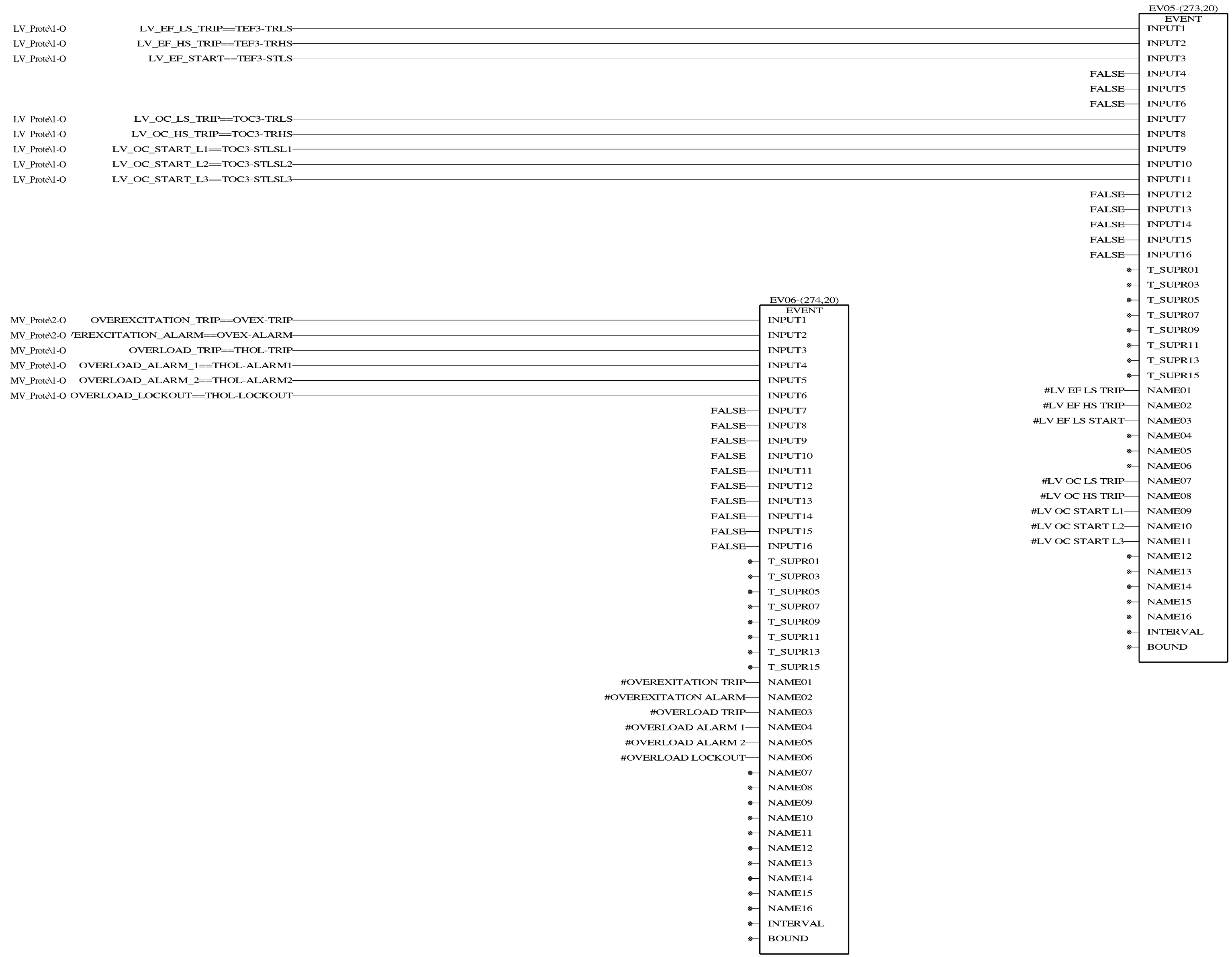
Events_v

Example 6

Sheet 1/6

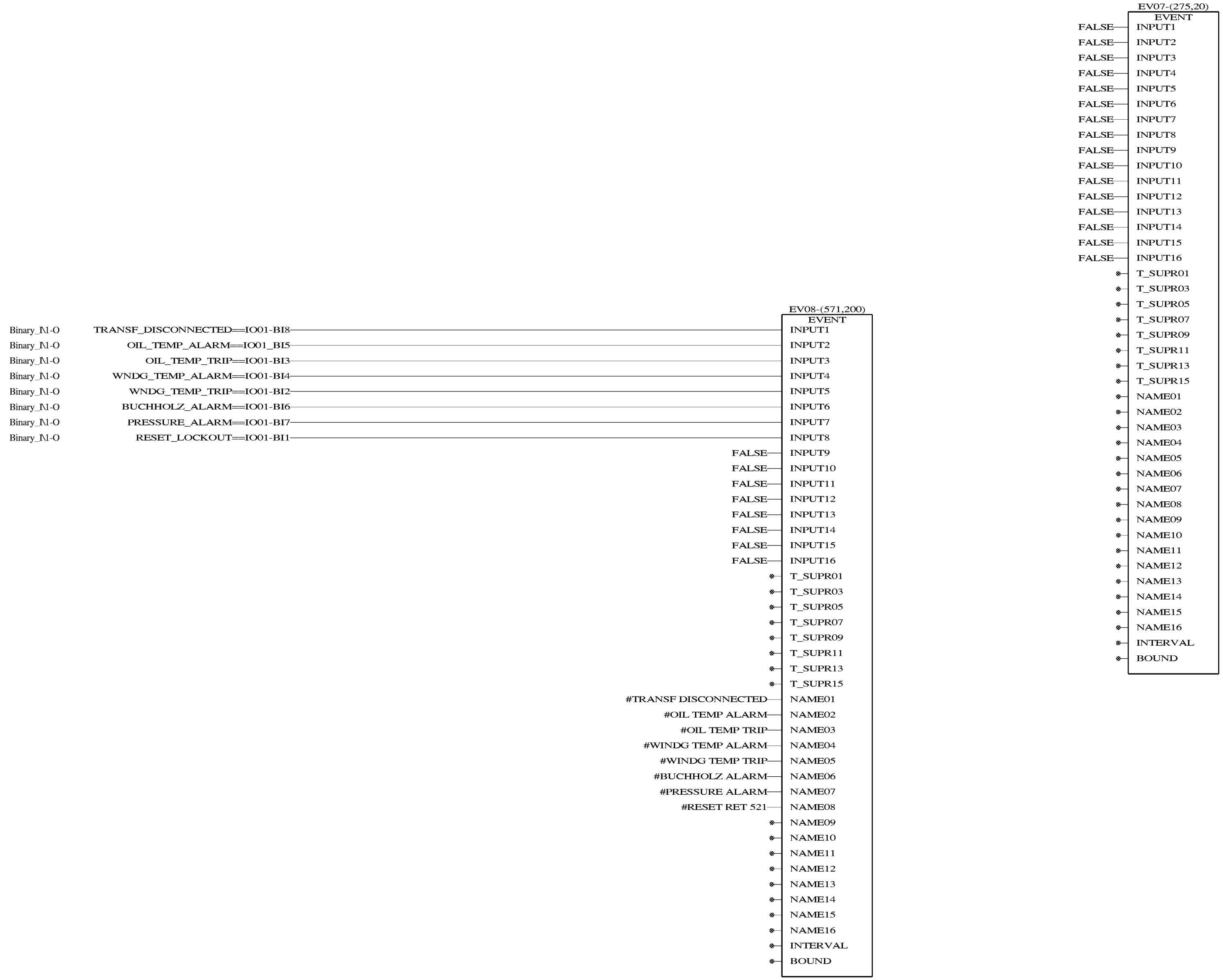


Prepared		02-04-15	RET521 2p4	Events_v
Approved	Birger Hillström	02-04-20		
Rev Ind	Reg nr		Resp dep SA/ATA	Rev Ind
Based on	Pcl		ABB Autom. Techn. Prod. AB	Example 6	Sheet 2/6

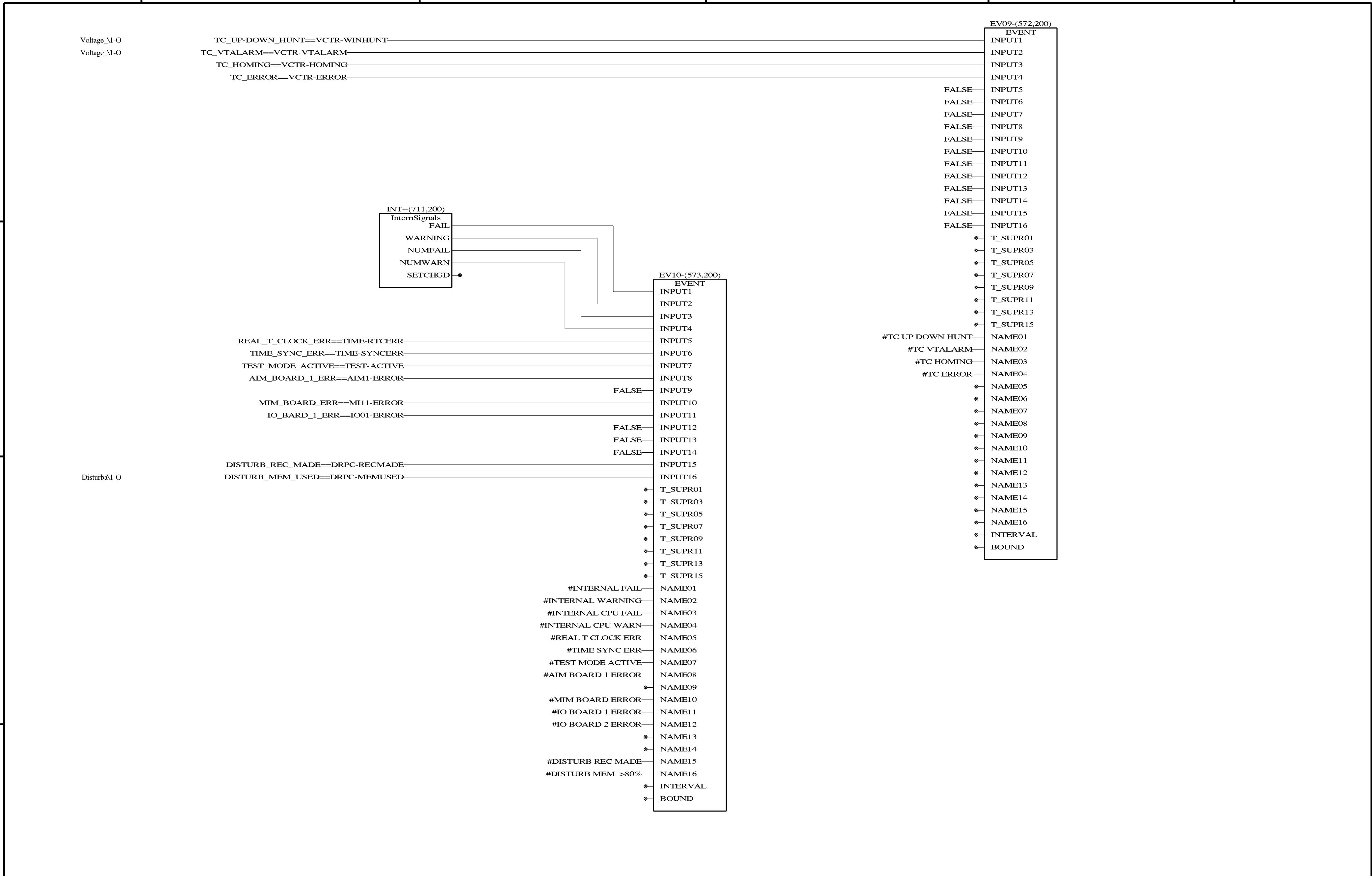


Prepared	02-04-15	RET521 2p4		Events_v
Approved Birger Hillström	02-04-20		Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr	ABB Autom. Techn. Prod. AB	Example 6	Sheet 3/6
Based on	Pcl			

Event block 07 free, preferably used by customer.



		Prepared	02-04-15	RET521 2p4	Events_v
		Approved Birger Hillström	02-04-20		
				Resp dep SA/ATA	Rev Ind
Rev Ind	Reg nr			ABB Autom. Techn. Prod. AB	Sheet 4/6
Based on	Pcl			Example 6	



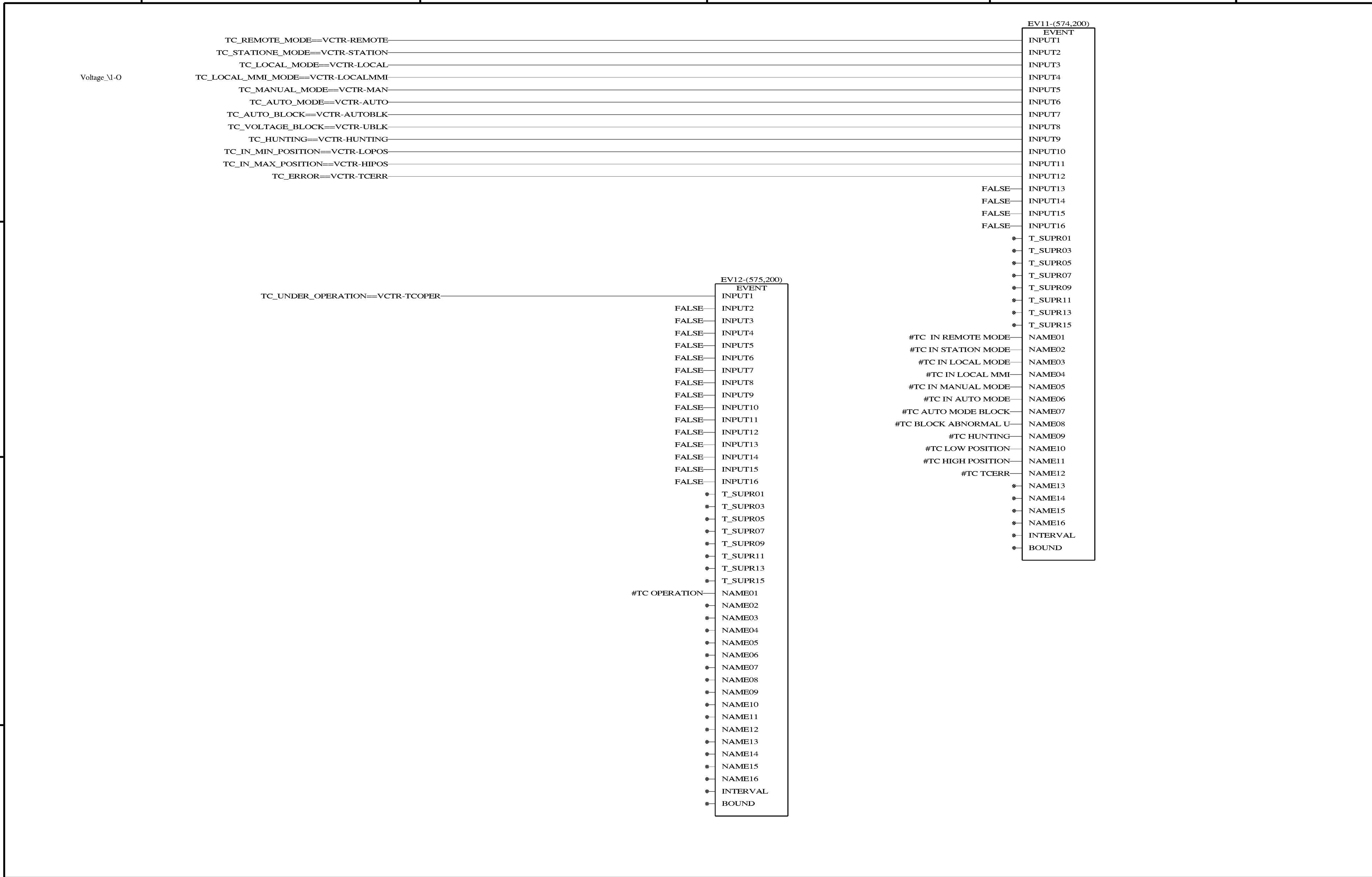
Prepared		02-04-15	RET521 2p4
Approved	Birger Hillström	02-04-20	
Rev Ind	Reg nr		
Based on	Pcl		ABB Autom. Techn. Prod. AB

Events_v

Resp dep SA/ATA Rev Ind

Example 6

Sheet 5/6



Rev Ind		Reg nr	Prepared	02-04-15	RET521 2p4
Based on		Pcl	Approved Birger Hillström	02-04-20	ABB Autom. Techn. Prod. AB

Events_v			
Resp dep	SA/ATA	Rev Ind	
Example 6			Sheet 6/6

1MRK 504 036-UEN

ABB Automation Technology Products AB
Substation Automation
SE-721 59 Västerås
Sweden
Telephone: +46 (0) 21 34 20 00
Facsimile: +46 (0) 21 14 69 18
www.abb.com/substationautomation

Printed on recycled and ecolabelled paper at Elanders Novum