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Application guide

The chapter "Application".

This chapter deals with the application of the protection terminal RET 521 and its individual basic and optional functions. Each function is dealt with for what and how it should be applied in a power network.

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Application of RET 521

1

Introduction

The numerical transformer terminal RET 521 is designed for fast and selective protection and control of two- and three-winding transformers, auto-transformers, generator-transformer blocks and shunt reactors.

The RET 521 has low requirements on the main Current Transformers and no interposing CTs are necessary.

Flexibility is provided to cover for different applications in form of transformer size, vector groups, system neutral earthing and extension of protection functions according to the user's preference. The selection of functionality from the modular hardware and software is made according to the requirements for selectivity and reliability and following the user's preference. Big and important transformers such as generator-transformer blocks or large network transformers can use two RET 521 and include the modular protection software selectively to obtain redundancy.

Smaller transformers and shunt reactors can include the modular software in one RET 521 and can also use the programmable logic to provide trip or indication for external protections (e.g. Buchholz). Thus providing a very compact design for protection and control.

The RET 521 includes setting adaptation to power transformer rating and instrument transformer ratios to allow protection settings in "per unit" (p.u.) or percent (%), of the power transformer rating, thus facilitating the protection settings to an optimum.

The RET 521 is supplied for 2-winding applications and 3-winding applications as indicated below in paragraph 1.1, and 1.2.

1.1

2-winding applications

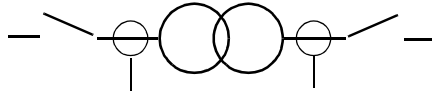


Fig. 1 2-winding power transformer

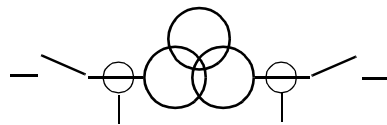


Fig. 2 2-winding power transformer with unconnected delta tertiary winding

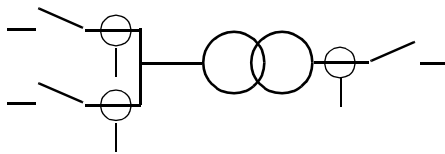


Fig. 3 2-winding power transformer with 2 circuit breakers on one side

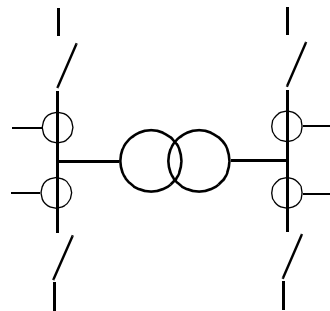


Fig. 4 2-winding power transformer with 2 circuit breakers and 2 CT-sets on both sides

1.2

3-winding applications

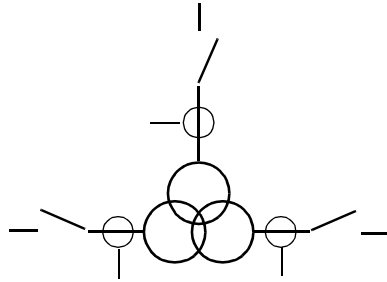


Fig. 5 3-winding power transformer with all three windings connected

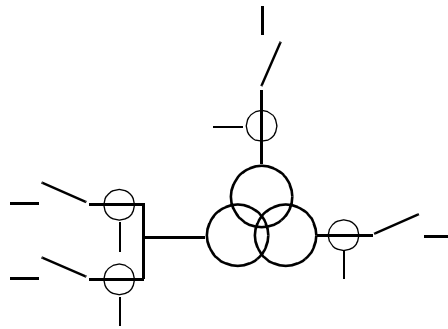


Fig. 6 3-winding power transformer with 2 circuit breakers and 2 CT-sets on one side

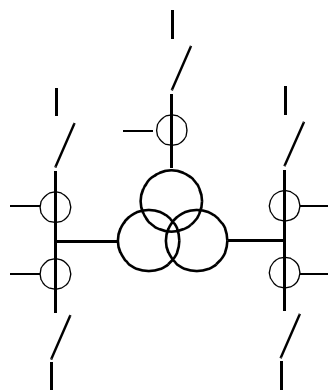


Fig. 7 3-winding power transformer with 2 circuit breakers and 2 CT-sets on 2 out of 3 sides

2 Service value reading

The Service report menu lets you display information about the:

- measured values from protection functions.
- operation conditions for protected objects in the power system.
- terminal.

The amount of available information depends on the number of basic and optional functions in a RET 521 terminal.

A certain subgroup is displayed on the local HMI if the corresponding function is installed in the terminal. These subgroups describe possible types of information:

- Analog Input Module (AIM)
- Binary Outputs
- Differential currents
- DisturbReport
- EarthFault
- Frequency Measurement
- MIM
- OverCurrent
- Overexcitation
- OverVoltage
- Thermal Overload
- UnderVoltage
- Voltage Control
- Active Group
- Internal time

3 Terminal identification

3.1 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 synchronised, (see the section “Time synchronisation”), to achieve higher time tagging correlation accuracy between terminals. Without synchronisation, 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.

3.2

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

3.3

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 synchronisation is enabled, time setting is not possible.

3.4

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	SW version for main program
CPU-module	CPU-module

3.5

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- <i><iomodulename></i>	Identity number of module in HW SlotNo 3
PCIP7- <i><iomodulename></i>	Identity number of module in HW SlotNo 7
CANP9- <i><iomodulename></i>	Identity number of module in HW SlotNo 9
CANP10- <i><iomodulename></i>	Identity number of module in HW SlotNo 10
CANP11- <i><iomodulename></i>	Identity number of module in HW SlotNo 11
CANP12- <i><iomodulename></i>	Identity number of module in HW SlotNo 12

3.6

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
Trafo-module	Trafo-module
ADC-module	ADC-module
HMI-module	HMI-module
Frame	Mechanical frame
Power-module	Power-module
LON-module	LON-module

4 Time synchronisation

4.1 General

The terminal has a built-in real time clock and calendar. The calendar starts with 1970 and lasts till 2038 and takes leap years into consideration. As with all real time clocks, it has a certain inaccuracy. Thus, in order to have the correct time for time tagging of events etc., it has to be synchronised. The terminal can accept synchronisation via either of the serial ports or via one of the binary inputs. Synchronisation via the serial ports will be done with absolute or relative time. Synchronisation via a binary input is done with minute pulses.

4.2 Synchronization via the serial ports

4.2.1 Synchronisation from SCS

The SCS will broadcast the synchronisation signals on the LON bus with absolute time every minute and with relative time every second. In order to get the correct absolute time, the PC for SCS must be synchronised from a world wide source, e.g. from a satellite or radio clock.

4.2.2 Synchronization from SMS

The SMS will broadcast the synchronisation signals on the SPA bus with absolute time every minute and with relative time every second. In this case a data communicator, e.g. SRIO 500 or SRIO 1000 is required. For proper synchronisation the data communicator should be synchronised from a world wide source, e. g. a satellite or radio clock.

4.3 Synchronisation via a binary input

The terminal accepts minute pulses to a binary input. These minute pulses can be generated from e.g. station master clock. In case the station master clock is not synchronised from a world wide source, time will be a relative time valid for the substation.

In case the objective of synchronisation is to achieve a relative time within the substation and no station master clock with minute pulse output is available, a simple minute pulse generator can be designed and used for synchronisation of the terminals. The minute pulse generator can be created using the logical elements and timers available in the terminal.

5 Activation of setting groups

5.1 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 optimised 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 five different ways:

- Locally by means of the local human-machine interface (HMI).
- Locally by means of a front-connected personal computer (PC).
- Remotely through the Station Monitoring System (SMS).
- Remotely through the Station Control System (SCS).
- Locally by means of up to four, programmable binary inputs, using the GRP function block.

6 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.

6.1 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 unauthorised 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.

6.2

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.

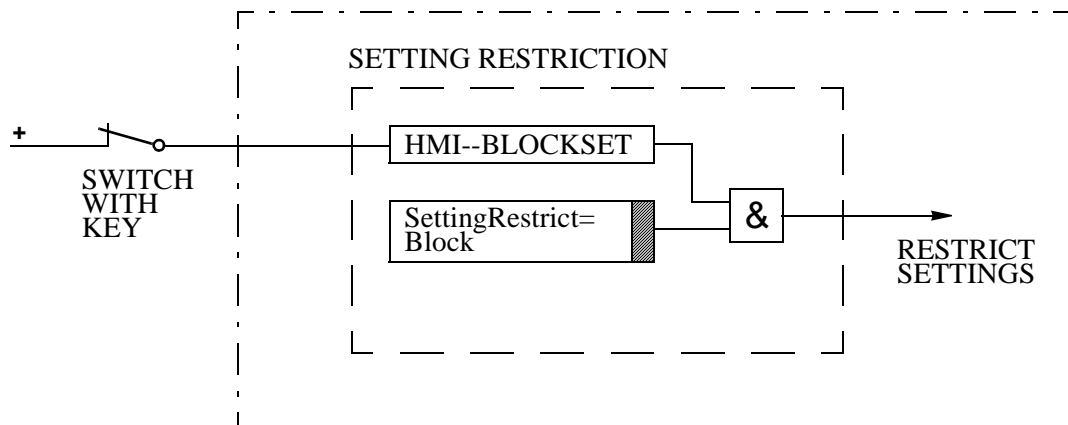


Fig. 8 Connection and logic diagram for the BLOCKSET function.

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.

Application of functions

7 I/O system configuration (IOHW)

7.1 General

This section describes the I/O system configuration that is used to add, remove, or move I/O modules in the RET 521 transformer terminal.

Two different I/O-buses are used in the terminal. These are the PCI and the CAN buses.

AIM, *Analog Input Modules* with 10 analogue input channels will be connected to the PCI bus, which can accommodate a maximum number of two slots, intended for the AIM. The maximum number of AIM modules in a RET 521 is two.

Four different types of I/O modules can be connected to the CAN bus, which can accommodate a maximum number of four slots, intended for I/O and analog input modules.

Available I/O modules that can be connected to the CAN bus:

- BIM, *Binary Input Module* with 16 binary input channels
- BOM, *Binary Output Module* with 24 binary output channels
- IOM, *Input/Output Module* with 8 binary input and 12 binary output channels
- MIM, *mA Input Module* with 6 analogue input channels

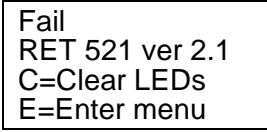
To configure, connect the function blocks that represent each I/O module (AIM, BIM, BOM, IOM, and MIM) to a function block for the I/O hardware positions (IOHW).

7.2 Functionality

Each module can be placed in any I/O slot for the corresponding bus in the product. To add, remove, or move modules in the product, reconfigure the product by using the CAP 531 configuration tool.

Users refer to the I/O slots by the physical slot numbers, which also appear in the product drawings. Available slots for the PCI bus are P3 and P7. The slots for the CAN bus are P9, P10, P11, and P12.

If the user-entered configuration does not match the actual configuration in the terminal, an error output is activated on the function block, which can be treated as an event or alarm, the green LED starts to flash and a fail message is displayed on the HMI:

A rectangular box with a black border containing the following text:

Fail
RET 521 ver 2.1
C=Clear LEDs
E=Enter menu

Fig. 9 Fail display

The AIM modules can be of three different types. The used type is chosen with a user-configurable function selector. As for the BIM, BOM and IOM, the same communication addresses will be used for all three types of AIM modules.

The BIM, BOM, and IOM share the same communication addresses for parameters and configuration. So they must share I/O module 01-04 (IOxx), which are the same function block. A user-configurable function selector per I/O module function block determines which type of module it is.

All names for inputs and outputs are inputs on the function blocks and are set fby using the CAP 531 configuration tool.

I/O modules that are not configured are not supervised. When an I/O module is configured as a logical I/O module (AIM, BIM, BOM, IOM, or MIM), the *logical I/O modules* are supervised.

Each logical I/O module has an error flag that is set if anything is wrong with any signal or the whole module. The error flag is also set when there is no physical I/O module of the right type present in the connected slot. When the error flag is set, the fail message (see Fig. 9) is displayed accompanied by the flashing green LED, and the erroneous module is pointed out.

7.3

Configuration

The configuration is made in two steps by using the CAP 531 configuration tool:

- 1 **Set the function selector for the logical I/O module to the type of I/O module that is used, AIM, BIM, BOM or IOM.**
- 2 **Connect the POSITION input of the logical I/O module to a slot output of the IOHW function block.**

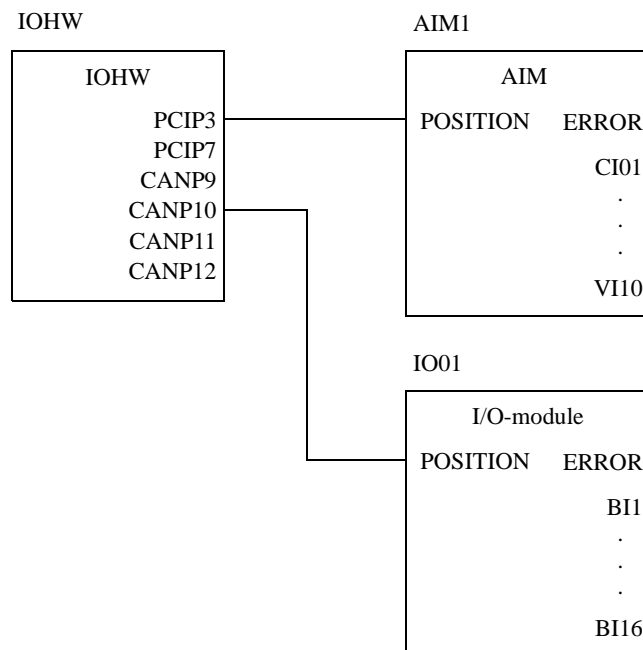


Fig. 10 Example of an I/O-configuration in the CAP 531 configuration tool for RET 521 with one AIM and one BIM

7.4

Setting

You can set the input names for analogue input, binary input and output modules (AIM, BIM, BOM, and IOM) from the CAP 531 configuration tool.

The binary input module (BIM) has a suppression function that blocks oscillating inputs on the module. You can set the oscillation blocking/release frequencies from the SMS or from the built-in HMI.

Refer to separate documents to set parameters from the SMS or from the built-in HMI for the analog input modules (AIM) and the mA input modules (MIM).

8 Activation of setting groups (GRP)

8.1 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 optimised regarding the conditions in power system.

The operational departments can plan different operating conditions for the primary equipment. The protection engineer can prepare in advance for the necessary optimised and pre-tested settings for different protection functions. Four different groups of setting parameters are available in the terminal. Any of them can be activated automatically through up to four different programmable binary inputs by means of external control signals.

The terminal have four independent groups (sets) of setting parameters. These groups can be activated at any time in five different ways:

- Locally by means of the local human-machine interface (HMI).
- Locally by means of a front-connected personal computer (PC).
- Remotely through the Station Monitoring System (SMS).
- Remotely through the Station Control System (SCS).
- Locally by means of up to four, programmable binary inputs.

8.2 Functionality

8.2.1 Activation by using binary inputs

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.

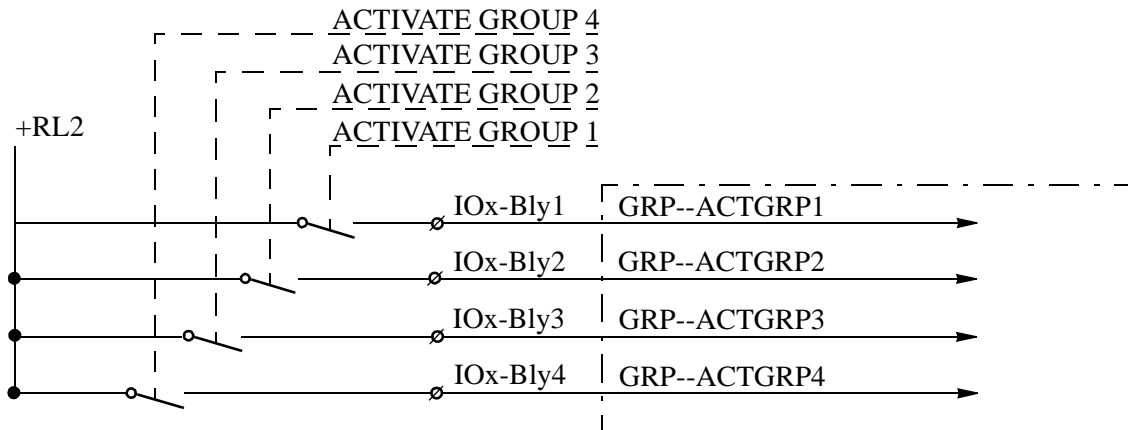


Figure 11: Connection of the function to external circuits.

The above example includes four output signals as well, for confirmation of which group that is active.

8.2.2

Using the HMI

Change active group by using the HMI menu branch:

Settings

ChangeAct Grp

8.2.3

Using SMS/SCS

Operating procedures for the PC aided methods of changing the active setting groups are described in the corresponding SMS documents and instructions for the operators within the SCS are included in the SCS documentation.

9

Configurable logic (CL)

9.1

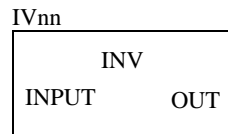
General

Different protection, control, and monitoring functions within the REx 5xx protection, control and monitoring terminals are quite independent as far as their configuration in the terminal is concerned. You cannot enter and change the basic algorithms for different functions. You can configure different functions in the terminals to suit special requirements for different applications.

For this purpose, you need additional logic circuits to configure the terminals to meet your needs and also to build in some special logic circuits, which use different logic gates and timers.

9.2**Function****9.2.1****Inverter (INV)**

The INV function block is used for inverting boolean variables.



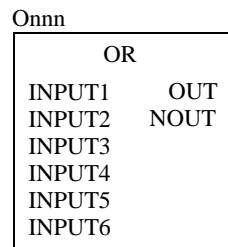
The output signal from the INV function block is set to 1 if the input signal is 0 and is set to 0 when the the input signal is 1. See truth table below.

Table 6: Truth table for the INV function block

INPUT	OUT
1	0
0	1

9.2.2**OR**

OR function blocks are used to form general combinatory expressions with boolean variables.



The output signal (OUT) is set to 1 if any of the inputs (INPUT1-6) is 1. See truth table below.

Table 7: Truth table for the OR function block

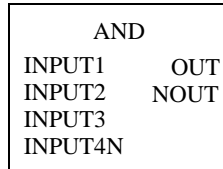
INPUT1	INPUT2	INPUT3	INPUT4	INPUT5	INPUT6	OUT	NOUT
0	0	0	0	0	0	0	1
0	0	0	0	0	1	1	0
0	0	0	0	1	0	1	0
...	1	0
1	1	1	1	1	0	1	0
1	1	1	1	1	1	1	0

9.2.3

AND

AND function blocks are used to form general combinatory expressions with boolean variables.

Annn



The output signal (OUT) is set to 1 if all the INPUT1-3 are 1 and INPUT4N is 0. See truth table below.

Table 8: Truth table for the AND function block

INPUT1	INPUT2	INPUT3	INPUT4N	OUT	NOUT
0	0	0	1	0	1
0	0	1	1	0	1
0	1	0	1	0	1
0	1	1	1	0	1
1	0	0	1	0	1
1	0	1	1	0	1
1	1	0	1	0	1
1	1	1	1	0	1
0	0	0	0	0	1
0	0	1	0	0	1
0	1	0	0	0	1
0	1	1	0	0	1
1	0	0	0	0	1
1	0	1	0	0	1
1	1	0	0	0	1
1	1	1	0	1	0

9.2.4

Timer

The configuration logic TM timer has outputs for delayed input signal at drop-out and at pick-up.

TMnn		
Timer		
INPUT		OFF
T		ON

The input variable to INPUT is obtained delayed a settable time T at output OFF when the input variable changes from 1 to 0 in accordance with the time pulse diagram, Fig. 12. The output OFF signal is set to 1 immediately when the input variable changes from 0 to 1.

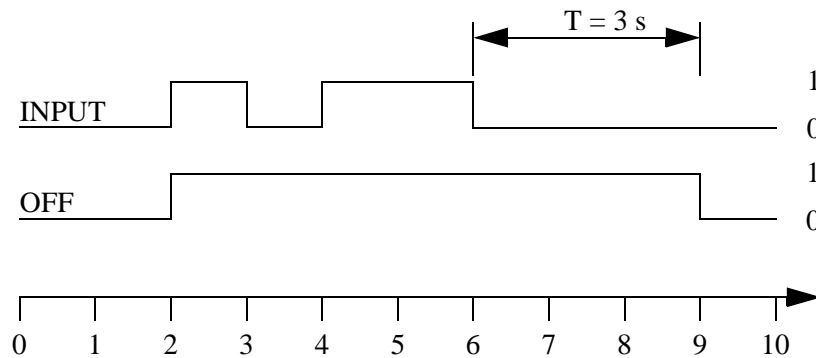


Fig. 12 Example of time diagram for a timer delayed on drop-out with preset time $T = 3\text{ s}$

The input variable to INPUT is obtained delayed a settable time T at output ON when the input variable changes from 0 to 1 in accordance with the time pulse diagram, Fig. 13. The output ON signal returns immediately when the input variable changes from 1 to 0.

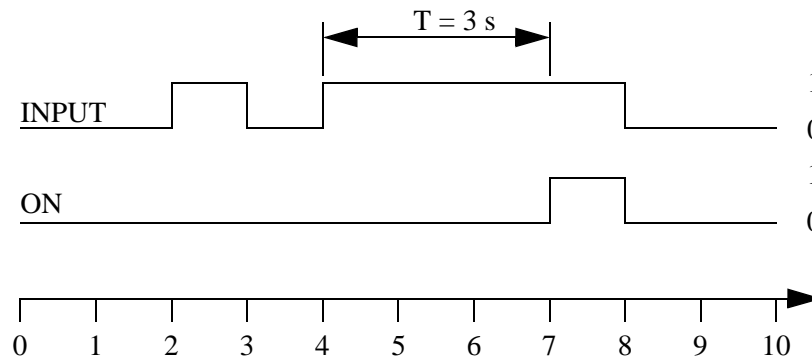


Fig. 13 Example of time diagram for a timer delayed on pick-up with preset time $T = 3\text{ s}$

If you need more timers than available in the terminals, you can use pulse timers with AND or OR logics. Fig. 14 shows an application example of how to realize a timer delayed on drop-out. Fig. 15 shows the realization of a timer delayed on pick-up. Note that the resolution of the setting time corresponds to the execution cycle of the logic as described in section “Configuration” on page 29.

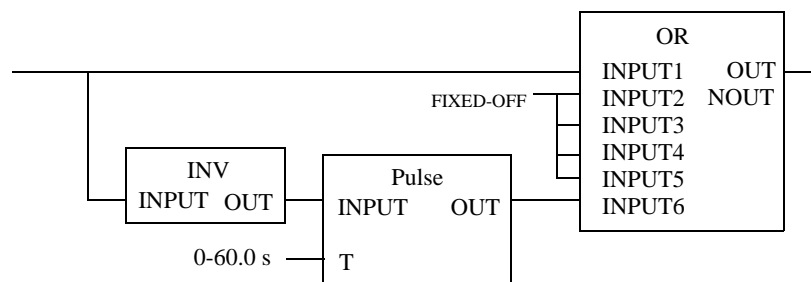


Fig. 14 Realization example of a timer delayed on drop-out

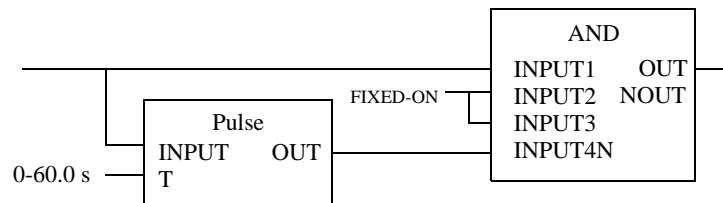
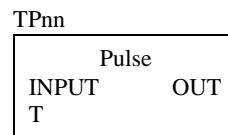


Fig. 15 Realization example of a timer delayed on pick-up

9.2.5

Pulse

The pulse function can be used, for example, for pulse extensions or limiting of operation of outputs.



A memory is set when the input INPUT is set to 1. The output OUT then goes to 1. When the time set T has elapsed, the memory is cleared and the output OUT goes to 0. If a new pulse is obtained at the input INPUT before the time set T has elapsed, it does not affect the timer. Only when the time set has elapsed and the output OUT is set to 0, the pulse function can be restarted by the input INPUT going from 0 to 1. See time pulse diagram, Fig. 16.

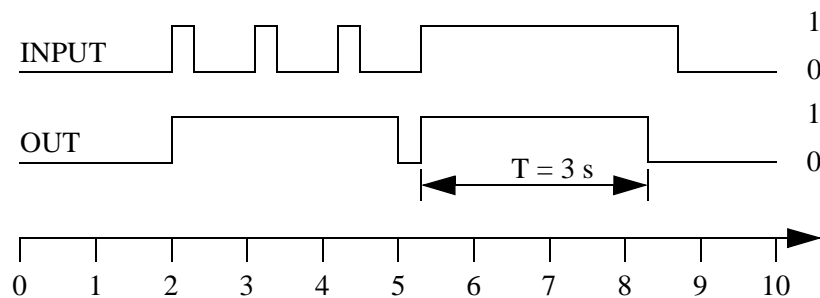


Fig. 16 Example of time diagram for the pulse function with preset pulse length $T = 3\text{ s}$

9.2.6

MOVE

The MOVE function blocks (may also be called copy-blocks) are used for synchronization of boolean signals sent between logics running with different execution cycle times.

There are two types of MOVE function blocks - MOF located *F*irst in the slower logic and MOL located *L*ast in the slower 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) available for the medium speed and four MOVE blocks (two MOF and two MOL) for the low speed.

Each MOVE block of 16 signals is protected from being interrupted by other logic application tasks. This guarantees the consistency of the signals to each other within each MOF and MOL function block.

Synchronization of signals with MOF should be used when a signal which is produced outside the slower logic is used in several places in the logic and there might be a malfunction if the signal changes its value between these places.

Synchronization with MOL should be used if a signal produced in the slower logic is used in several places outside this logic, or if several signals produced in the slower logic are used together outside this logic, and there is a similar need for synchronisation.

Fig. 17 shows an example of logic, which can result in malfunctions on the output signal from the AND gate to the right in the figure.

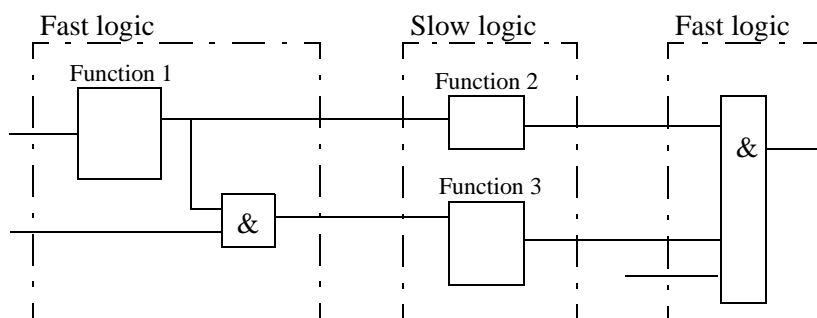


Fig. 17 Example of logic, which can result in malfunctions

Fig. 18 shows the same logic as in Fig. 17, but with the signals synchronized by the MOVE function blocks MOFn and MOLn. With this solution the consistency of the signals can be guaranteed.

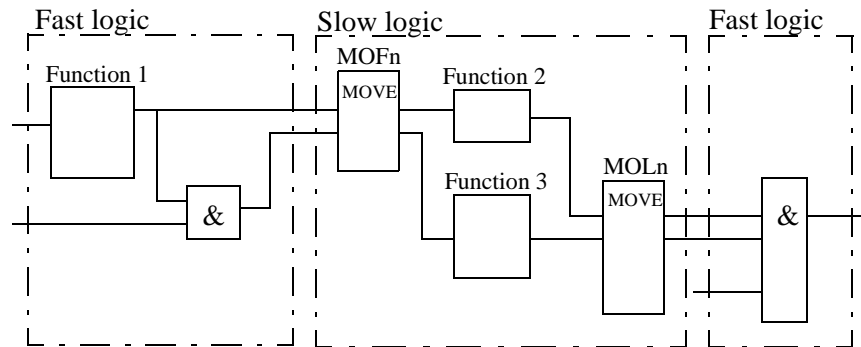


Fig. 18 Example of logic with synchronized signals

9.3

Setting

The time delays and pulse lengths for Timer and Pulse function blocks are set from the CAP 531 configuration tool.

Both timers in the same logic block (the one delayed on pick-up and the one delayed on drop-out) always have a common setting value.

Setting values of the pulse length are independent on one another for all pulse circuits.

9.4

Configuration

The configuration of the logics is performed from the CAP 531.

Execution of functions as defined by the configurable logic blocks in RET 521 runs in a fixed sequence in three different execution cycle times with maximum speed, mediate speed and low speed.

For each cycle time, the function block is given an execution serial number. This is shown when using the CAP 531 configuration tool with the designation of the function block and the cycle time, for example, TMnn-(1044, 20). TMnn is the designation of the function block, 1044 is the execution serial number and 20 is the cycle time.

Execution of different function blocks within the same cycle time should follow the same order as their execution serial numbers to get an optimal solution. Always remember this when connecting in series two or more logical function blocks. When you connect function blocks with different cycle times, see the use of MOVE function blocks in the section “MOVE” on page 28.

So design the logic circuits carefully and check always the execution sequence for different functions. In the opposite cases, additional time delays must be introduced into the logic schemes to prevent errors, for example, race between functions.

10 Command function (CM/CD)

10.1 General

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. 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. In the REx 5xx terminals it is also possible to receive data from other terminals via the LON bus.

Two types of command function blocks are available, Single Command and Multiple Command.

10.2 Single Command function

The outputs from the Single Command function block can be individually controlled from the operator station, remote-control gateway, or from the built-in HMI. Each output signal can be given a user-defined name.

The output signals are available for configuration to built-in functions or via the configuration logic circuits to the binary outputs of the terminal.

The command functions can be connected according to the application examples in Fig. 19 to Fig. 21. Note that the execution cyclicity of the configured logic connected to the command function block cannot have a cycle time longer than the command function block.

Fig. 19 shows an example of how the user can, in an easy way, connect the command function via the configuration logic circuit to control a high-voltage apparatus. This type of command function is normally performed by a pulse via the binary outputs of the terminal. Fig. 19 shows a close operation, but an open operation is performed in a corresponding way without the synchro-check condition.

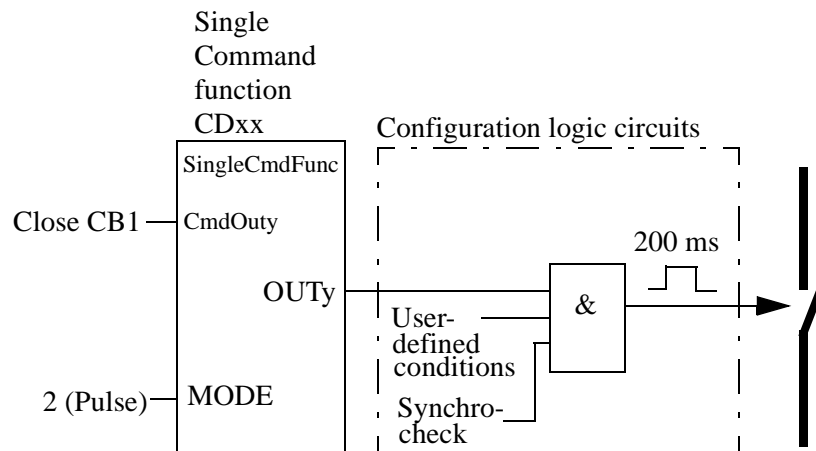


Fig. 19 Application example showing a logic diagram for control of a circuit breaker via configuration logic circuits

Fig. 20 and Fig. 21 show other ways to control functions, which require steady signals On and Off. The output can be used to control built-in functions or external equipment.

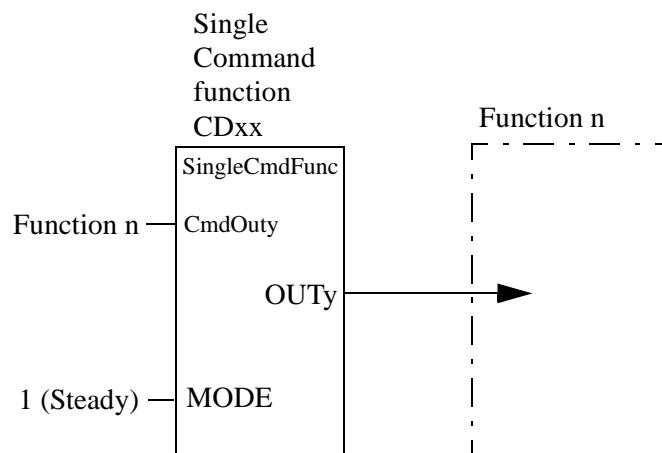


Fig. 20 Application example showing a logic diagram for control of built-in functions

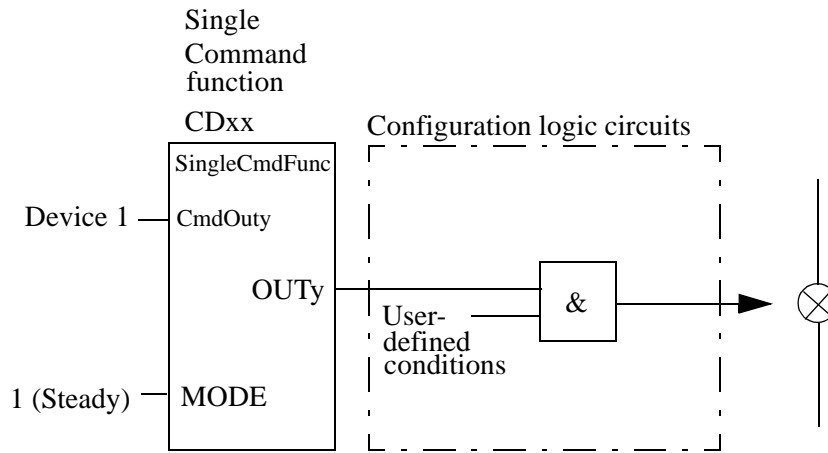


Fig. 21 Application example showing a logic diagram for control of external equipment via configuration logic circuits

10.3

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 user-defined name can be given for the whole block.

The output signals are available for configuration to built-in functions or via the configuration logic circuits to the binary outputs of the terminal.

10.4

Communication between terminals

The Multiple Command function block can also be used to receive information over the LON bus from other terminals. The most common use is to transfer interlocking information between different bays. That can be performed by an Event function block as the send block and with a Multiple Command function block as the receive block. The configuration for the communication between terminals is made by the LON Network Tool.

10.5

Commands from built-in HMI

The outputs of the Single Command function block can be activated from the built-in HMI. This can be performed under the menu:

Command
CDxx

Fig. 22 shows the dialogue box for the built-in HMI after the selection of the command menu above. The display shows the name of the output to control (CmdOut1) and the present status (Old) and proposes a new value (New).

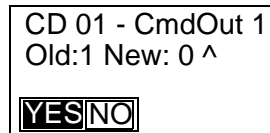


Fig. 22 Command dialogue to control an output from the Single Command function block

The dialogue to operate an output from the Single Command function block is performed from different states as follows:

- 1 Selection active; select the:
 - C button, and then the No box activates.
 - Up arrow, and then New: 0 changes to New: 1. The up arrow changes to the down arrow.
 - E button, and then the Yes box activates.
- 2 Yes box active; select the:
 - C button to cancel the action and return to the CMD/CDxx menu window.
 - E button to confirm the action and return to the CMD/CDxx menu window.
 - Right arrow to activate the No box.
- 3 No box active; select the:
 - C button to cancel the action and return to the CMD/CDxx menu window.
 - E button to confirm the action and return to the CMD/CDxx menu window.
 - Left arrow to activate the Yes box.

10.6

Setting

The setting parameters for the Single Command function and Multiple Command function are set from the CAP 531 configuration tool.

Parameters to be set for the Single Command function are MODE, common for the whole block, and CmdOuty - including the name for each output signal. The MODE input sets the outputs to be one of the types Off(0) , Steady(1), or Pulse(2).

The Multiple Command function has a common name setting (CmdOut) for the block, MODE as above and INTERVAL used for the supervision of the cyclical receiving of data.

11

Frequency measurement function (FRME)

11.1

General

The majority of protection and control functions in RET 521 are based on the fundamental frequency component of the analogue input signals. Since the unwanted harmonic components are generally present in the analogue input signal, a Discrete Fourier Filter (DFF) is implemented in order to extract the fundamental component out of it. As implemented in RET 521 the DFF has a “full cycle” window length with 20 samples and it is pre-designed for nominal power system frequency (i.e. 50Hz or 60Hz). As a result of DFF calculation the magnitude and phase angle of the fundamental component phasor of the analogue input quantity are obtained.

It can be shown that the DFF has excellent filter properties when the frequency of the fundamental component of the analogue input signal corresponds to the DFF window length. But in case when the frequency of the fundamental component of the input signal deviates from the DFF window length an additional error is introduced. This error can be tolerated for small frequency deviation of the analogue input signal (i.e. $\pm 2\text{Hz}$), but for larger deviations of frequency this error can not be tolerated.

Therefore it is absolutely necessary to account for this error for applications where the frequency of the analogue input signal can vary considerably (i.e. generator step-up transformers, or network transformers close to the large generating plants).

Within RET 521 a specially designed and patented algorithm for frequency measurement and tracking is implemented. The algorithm is located within the FRME function. This algorithm enables all other protection and control function within the protection terminal to be utilized within the extended frequency range from 0,7 to 1,2 of nominal power system frequency (i.e. 50Hz or 60Hz). In the same time the actual power system frequency is available as a Service Value on the built-in HMI and on SMS PC. More details about this algorithm can be found under section Technical Descriptions.

11.2

Measured quantities

In order to measure and track power system frequency the FRME function shall be configured to measure the voltage signal. Use one of the following two types of voltage input signals:

- Three Phase-to-Ground Voltages (frequency measurement is than based on positive sequence phasor which is internally calculated)
- One Phase-to-Phase voltage (frequency measurement is than based on that phase-to-phase voltage phasor)

Voltage input from any of the power transformer windings can be used for this measurement.

Configuration of the FRME function can be done only by CAP 531 configuration tool.

11.3**Settings**

The FRME function has only one setting parameter “Operation” which is used to set this function ON or OFF.

12**Transformer differential protection (DIFP)**

Differential protection is one of the most important and the most commonly used protection for transformers of approximately 10 MVA and above. The differential protection simplicity of comparing current into all terminals of the transformer gives it a very high reliability. The differential protection does an excellent job of meeting a large number of the protection requirements but must be combined with other protections to provide full transformer protection.

RET 521 has two variants of transformer differential protections intended for two-winding and three-winding transformers. Five restrained three-phase currents are available.

12.1**General**

The transformer differential protection is a unit protection. It serves as the main protection of transformers in case of faults in the windings. The protective zone of a differential protection includes the transformer itself, the bus-work or cables between the current transformer and the power transformer.

When bushing current transformers are used for the differential relay, the protective zone does not include the bus-work or cables between the circuit breaker and the power transformer. In some substations there is a current differential protection for the busbar. Such a busbar protection will include the bus-work or cables between the circuit breaker and the power transformer.

Electrical internal faults are very serious and cause immediate serious damage. Short-circuits and earth-faults on windings and terminals are generally detectable by the differential protection. Interturn fault, which is flashover between conductors within the same physical winding, is also possible to detect if enough number of turns are short-circuited. Interturn faults are the most difficult transformer winding faults to detect with electrical protections.

A small interturn fault including just a few turns will result in an undetectable amount of current until it has develop into an earth-fault. For this reason it is important that the differential protection has a high sensitivity and that it is possible to use a sensitive setting without causing unwanted operations for external faults.

It is important that the faulted transformer should be disconnected as fast as possible. As the differential protection is a unit protection it can be designed for fast tripping, thus providing selective disconnection of the faulty transformer. The differential protection should never operate to faults outside the protective zone.

A transformer differential protection compares the current flowing to the transformer with the current leaving the transformer. Power transformers introduce often 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 the differential protection.

Traditional transformer differential protection functions required auxiliary transformers for correction of the phase shift and ratio. Numerical microprocessor based differential algorithm as implemented by RET 521 compensate for both the turns-ratio and the phase shift internally in the software. No auxiliary current transformers are necessary. The rated data and vector group for the power transformer and the rated currents of the CTs have to be set from SMS or built-in HMI. See the sections “Power transformer data” on page 142 and “Current and voltage transformer data” on page 148 for details.

The differential current should theoretically be zero during normal load or external faults if the turn-ratio and the phase shift are correctly compensated. However, there are several different phenomena other than internal faults that will cause unwanted and false differential currents. The main reasons for unwanted differential currents are:

- mismatch due to different position of the tap changer
- different characteristics, loads and operating conditions of the current transformers
- zero sequence currents that only flow on one side of the power transformer
- normal magnetizing currents
- magnetizing inrush currents
- overexcitation magnetizing currents

The following paragraphs describe how these reasons of unwanted differential currents can be taken into consideration.

12.2

Magnetizing inrush current

The magnetizing inrush is a transient condition which occurs when a power transformer is energized. Similar inrush currents flow when the voltage return to normal after the clearance of shunt faults. The magnetizing current appears as a differential current to the transformer differential protection. It is not a fault condition and the protection must remain stable during the inrush transient, a requirement which is a major factor in the design of differential protection for transformers. With improved modern steels in the manufacture of power transformers, and application of very fast differential relays, magnetizing inrush phenomena came into more prominence.

The shape, magnitude and duration of the inrush current depend on the following characteristic factors:

- the source impedance
- the size of the transformer
- the location of energized winding
- the connection of the windings
- the point of wave when the breaker closes
- the magnetic properties of the core
- the remanence of the core
- the use of pre-insertion resistors

The inrush current can appear in all three phases and in an earthed neutral. The magnitude of the inrush current to the inner winding is larger than the inrush current to the outer winding. The magnitude of the inrush current is 10-20 times in the first case and 5-10 times the rated current in the second case. Usually, the high-voltage winding is the outer winding and the low-voltage winding is the inner winding. The inrush current decays 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.

The maximum inrush current develops if the switching occurs when the voltage is close to zero and the new flux from the inrush current gets the same direction as the remanent flux. The sum of the two fluxes can exceed the saturation flux. The inrush current will be small when the new flux from the inrush current gets the opposite direction as the remanent flux. The magnitude of the inrush current depends therefore on the point on wave when we close the transformer switch.

The source impedance of the power system and the air-core reactance of the energized winding determine the magnitude of the inrush current when the core saturates. The probability that the maximum inrush current should occur is low. One out of 5-6 times, the switching should generate an inrush current close to the maximum.

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 second 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.

12.2.1

Inrush restraint methods

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 time axis. The 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 substantially increases the proportion of the second harmonic, being up to more than 60 % of the fundamental harmonic.

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

Sensitive differential protections may operate incorrectly when a power transformer is energized. To make a differential protection stable against inrush currents, measures must be taken in order to make the algorithm capable to distinguish the inrush phenomena from a fault. It is necessary to provide some forms of detection of inrush conditions and restrain the differential protection.

Second harmonic restraint is an effective method to avoid unwanted operations when energizing a power transformer, as the second harmonic always is present in the inrush current. The second harmonic content of a differential current is compared to the fundamental harmonic of the same differential current and if the ratio is higher than a set limit, then an inrush condition is assumed.

Normal primary fault currents do not contain second or other even harmonics. The secondary current of a current transformer which is energized into steady state saturation will also contain odd harmonics but not even harmonics. However, should the current transformer be saturated by the transient component of the fault current, the resulting saturation is not symmetrical and even harmonics are introduced into the output current. This can have the disadvantage of increasing the fault clearance time for heavy internal faults with current transformer saturation.

With a combination of the second harmonic restraint and the waveform restraint methods it is possible to get a protection with high security and stability against inrush effects and at the same time maintain high performance in case of heavy internal faults even if the current transformers are saturated.

Both these restraint methods are applied by RET 521. Two possible combinations are available. The default or standard method (conditionally) is to let the harmonic and the waveform methods operate in parallel only when the power transformer is not yet energized, and switch off the second harmonic criterion when the power transformer has been energized. The second harmonic method is also active a short time when heavy external fault has been detected. The second method (always) is to let the second harmonic method be active all the time. The waveform method operates in parallel all the time. The choice of combination of restraint method is done with a setting parameter. Option Conditionally is recommended as the default setting. Option Always can be used to increase the stability if the current transformers are sufficiently large so that the harmonics produced by transient saturation do not delay normal operation of the protection.

The second harmonic restraint function has a settable level. If the ratio of the second harmonic to fundamental harmonic in the differential current is above the settable limit, the operation of the differential protection is restrained. It is recommended to use the setting 15 % as a default value in case no special reasons exist to choose an other setting.

12.3

Overexcitation magnetizing current

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

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

Both excessive voltage and lower frequency will tend to increase transformer flux density. An overexcited transformer is not a transformer fault. It is an abnormal network condition for which a transformer differential protection should not operate. The differential protection must remain stable during the overexcitation condition.

12.3.1

Overexcitation restraint method

Overexcitation current contains odd harmonics, because the waveform is symmetrical about the time axis. As the third harmonic currents cannot possible flow into a delta winding, the fifth 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 component with little odd harmonics. In this instance the fifth harmonic limit must be set to a relatively low value.

RET 521 differential protection function is provided with a fifth harmonic restraint to prevent the protection from operation during an overexcitation condition of a power transformer. If the ratio of the fifth harmonic to fundamental harmonic in the differential current is above a settable limit the operation is restrained. It is recommended to use the setting 25 % as a default value in case no special reasons exist to choose an other setting.

Transformers likely to be exposed to overvoltage or underfrequency conditions should be provided with an overexcitation protection based on V/Hz to achieve trip before the internal limit is reached.

12.4

Normal service

During normal service a small differential current flows through the differential protection. The current is due to the excitation current of the power transformer, ratio errors in the current transformers and changes of the position of the tap changer, if provided.

Normal magnetizing currents are of the order of 1 % or less which is low in comparison with the operate value of the differential protection and can be neglected.

The power transformer ratio changes as a result of changing the tap of an on-load tap changer. This will cause false differential currents to the differential protection function if not the tap position is known. A tap changer in the end position gives a differential current of 10-20 % of load current depending of the regulating range of the tap changer. If the tap position is not known, the actual ratio will only match at one point of the tap changing range. Therefore, the mismatch due to this must be taken care of by setting a lower base sensitivity of the differential protection. A setting of 10-15 % higher than the mismatch is usual.

12.4.1

Tap changer position adaption

If the tap position is known and the differential function is supplied with regularly updated information about the tap changer position an adaption to the actual turn ratio can be done. In this case it is possible to set a much higher sensitivity of the differential protection. RET 521 has this feature.

12.5

External faults

For faults outside the protective zone a relatively large differential current can occur due to the position of the tap changer and differences between the current transformers. At maximum through fault current the unwanted differential current produced by a small percentage unbalance may be substantial. There is a risk for current transformer saturation for heavy faults just outside the protective zone. The differential protection should not operate for the differential current in these cases.

12.5.1**Restrained differential protection**

To make a differential relay as sensitive and stable as possible, restrained differential protections have been developed and are now adopted as the general practice in the protection of power transformers. The protection should be provided with a proportional bias which makes the protection operate for a certain percentage differential current related to the current through the transformer. This stabilizes the protection under through fault conditions while still permitting the system to have good basic sensitivity.

The bias current can be defined in many different ways. One classical way of defining the bias current has been $I_{bias} = (I_1 + I_2) / 2$, where I_1 is the magnitude of the power transformer primary current, and I_2 the magnitude of the power transformer secondary current. However, it has been found that if the bias current is defined as the highest power transformer current this will reflect the difficulties met by the current transformers much better.

The differential protection function in RET 521 uses the highest current of all power transformer inputs as bias current. The currents are scaled with the relation of the power transformer winding current rating to its CT primary current rating and then referred to the same side of the power transformer. This is done in order to let the bias current reflect the working situation for the current transformer especially in cases where the transformer rated current and the CT primary rated current differs considerably. This is often the case in applications with T-connections. The main philosophy behind the principle with the operate bias characteristic is to decrease the operate sensitivity when the current transformers have difficult operating conditions. This bias quantity gives the best stability against an unwanted operation of the overall differential protection. Fig. 23 shows the set of 5 operate-bias characteristics that are available in RET 521.

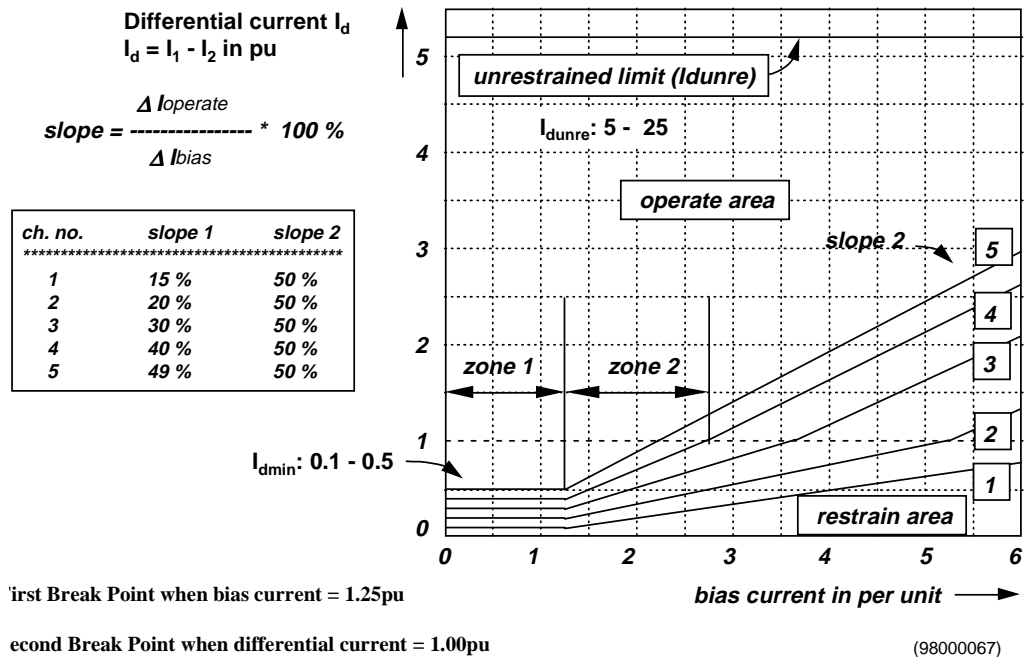


Fig. 23 RET 521 set of operate-bias characteristics

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 judgment. The second slope is increased to ensure stability under heavy through fault conditions which could lead to increased differential current due to saturation of current transformers.

Characteristic number 3 and the default sensitivity, $I_{d\text{min}}$ set to 30 % of the power transformer rated current can be recommended as a default setting in normal applications. If the conditions are known more in detail, higher or lower sensitivity can be chosen. The selection of suitable characteristic should in such cases be based on the knowledge of the class of the current transformers, availability of information on the on load tap changer (OLTC) position, short circuit power of the systems, etc. If the differential function is supplied with regularly updated information about the OLTC position it is possible to set a higher sensitivity.

Transformers can be connected to buses in such ways that the current transformers used for the differential protection will be either in series with the power transformer windings or the current transformers will be in breakers that are part of the bus, such as a breaker-and-a-half or a ring bus scheme. For current transformers with primaries in series with the power transformer winding, the current transformer primary current for external faults will be limited by the transformer impedance.

When the current transformers are part of the bus scheme, as in the breaker-and-a-half or the ring bus scheme, the current transformer primary current is not limited by the power transformer impedance. High primary currents may be expected. In either case, any deficiency of current output caused by saturation of one current transformer that is not matched by a similar deficiency of another current transformer will cause a false differential current to appear.

Differential protection can overcome this problem if the bias is obtained separately from each set of current transformer circuits. It is therefore important to avoid paralleling of two or more current transformers for connection to a single restraint input. Each current connected to RET 521 is available for biasing the differential protection function.

12.5.2

Elimination of zero sequence currents

A differential protection may operate unwanted to external earth faults in cases where the zero sequence current can flow only on one side of the power transformer but not on the other side. This is the situation when the zero sequence current cannot be properly transformed to the other side of the power transformer. Power transformer connection groups of Yd or Dy type cannot transform the zero sequence current. If a star winding neutral point is earthed or a delta winding of a power transformer is earthed via an earthing transformer inside the zone protected by the differential protection there will be an unwanted differential current in case of an external earth fault.

To make the overall differential protection insensitive to external earth faults in these situations the zero sequence currents must be eliminated from the power transformer terminal currents, so that they do not appear as the differential currents. This had once been achieved by means of intermediate current transformers. The elimination of zero sequence current is done numerically in RET 521 and no auxiliary transformers or zero sequence traps are necessary.

12.6

Internal faults

For faults inside the protective zone, a current proportional to the fault current occurs in the differential circuits and the transformer differential protection will operate.

The transformer differential protection is often provided with an unrestrained differential function. The unrestrained differential protection offers faster fault clearance for heavy internal faults and it is not blocked for magnetizing inrush or overexcitation magnetizing currents. The purpose of the unrestrained differential protection is also to exclude the risk of excessive restraint resulting from the harmonic distortions of the secondary currents from the current transformers in case of heavy internal faults.

The current setting for the unrestrained function has to be set above the maximum inrush current when the transformer is energized. As the magnitude depends on several factors it is difficult to accurately predict the maximum anticipated level of inrush current. The magnitude is normally within the range 5-20 times the rated current of the power transformer (I_r).

RET 521 differential protection function is provided with an unrestrained differential function, that measures the fundamental harmonic of the differential current. The differential current operate value can be set in the range 5 to 25 times the rated current of the power transformer. The following settings can be recommended

Power transformer connection	Rated power MVA	Recommended setting x I_r when energizing from	
		High voltage side	Low voltage side
Yy	< 10	13	13
Yy	10-100	9	9
Yy	> 100	5	5
Yd	-	9	9
Dy	< 100	9	13
Dy	> 100	5	9

The power transformers are assumed to be step-down transformers with power flow from the high voltage side to the low voltage side.

A setting of $13 \times I_r$ or higher can be required when very large through fault currents may saturate the current transformers and cause a large differential current. This can for example be the case when the bus is included in the protective zone of the differential protection or when a breaker-and-a-half arrangement is used.

13

Three-phase time overcurrent protection (TOC)

13.1

General

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 windings and the transformer core. Furthermore, a fault with high fault currents may cause a high gas pressure. If the pressure gets too high, it will damage the transformer tank. Depending on the magnitude of the fault current overcurrent protections can be used to clear these faults.

High fault currents may flow through a transformer when an external shunt fault occurs on the network and may produce a relatively intense rate of heating of the transformer. This can result in damage to the transformer. The copper losses increase in proportion to the square of the per unit fault current. If the current is limited only by the reactance of the transformer, the duration of external short-circuits that a transformer can withstand without damage is relatively short. Phase overcurrent protection is an important protection that can be used to clear the transformer before the transformer is damaged.

Transformer failures are seldom transient ones and the magnitude of the fault current depends on:

- the short-circuit capacity of the power networks
- the system earthing of the connected networks
- the leakage reactance of the transformer
- the position of the fault along the winding

A short-circuits between the phases will cause a substantial fault current. The magnitude of the fault current depends mainly on the source impedance and the leakage impedance of the transformer.

An earth fault is a metallic contact or flashover between a winding and an earthed part such as the core or the tank. The actual value of the earth fault current will depend on the way the system is earthed and the position of the fault along the winding. The phase currents can be high enough to be detected by a phase overcurrent protection in case of earth faults in solidly earthed systems. However, in many other situations the individual phase currents may be relatively low and are not possible to be detected by the phase overcurrent protection.

A metallic contact or flashover between conductors within the same physical winding causes an interturn fault. An interturn fault short-circuits a small part of the winding. The current in the short-circuited turns will become very high but the influence on the phase currents of the transformer will be very small. Interturn faults are very difficult to detect by protection equipment using electrical input quantities only, but can be detected by using a Buchholz relay.

The phase overcurrent protection is mainly a protection for phase to phase faults but can sometimes also operate for earth faults. The overcurrent protection has very small possibility to detect interturn faults. This must be remembered when considering the performance of a transformer protection scheme.

Depending on the size of the power transformer, the voltage level and the performance of the overall protection scheme, the phase overcurrent protections for power transformers can have several different purposes.

Small power transformers often have an overcurrent protection as main protection though overcurrent protections have inferior sensitivity and are slower than differential protections.

Many large transformers have an overcurrent protection as back-up protection for internal faults. The overcurrent protection will sometimes serve as main protection for the busbar fed from the power transformer. It will often serve as a back-up protection for the busbar and the outgoing power lines fed from the power transformer.

Generally, overcurrent phase protections provide some additional protection for through fault withstand but do not provide adequate primary protection in many applications.

13.2

Short-circuit protection

The phase overcurrent protection is an inexpensive, rather simple, and reliable scheme for fault detection and is used for some transformer protection applications. Sensitive settings and at the same time fast operations are normally not possible with overcurrent protections. The protection will provide limited protection for internal transformer faults. It suffers from having to be set high for transformer inrush, for coordination for down line protections, and to allow transformer overloads that it is ineffective for low magnitude internal transformer faults. Fast operation is often not possible since the transformer protection should be coordinated with the protection for the feeders connected to the busbar.

It should be observed that the sensitivity of a phase overcurrent protection, applied on one side of a Dy transformer, is changed during unsymmetrical faults on the other side of the transformer. The table shows some examples of how the phase currents will be influenced by the phase shift of transformers.

Transformer connection	Fault on low-voltage side	Low-voltage current	High-voltage current in phase		
			a	b	c
Dy0	ph-earth	1.0	0.58	0	0.58
Dy Yd	ph-ph	1.0	1.15	0.58	0.58
All types	three ph	1.0	1.0	1.0	1.0

For example only one of the phases on the high-voltage side of a Yd transformer carries full short-circuit current. The two other phases on the high-voltage side carry only 50 percent of the current. The sensitivity of an overcurrent protection that measures the currents in just two phases on the high-voltage side may be only 50 percent of the sensitivity of an overcurrent protection that measures the currents in all three phases on the high-voltage side. An overcurrent protection on the high-voltage side shall therefore be connected to three current transformers, one in each phase, and measure the current in all three phases.

The overcurrent protections should have an inverse-time element whose pickup can be adjusted to somewhat above maximum rated load current including the overload capacities of the transformer, and with sufficient time delay to be selective with the protections of adjacent power system components during external faults. When overcurrent protection is applied to the high voltage side of a transformer with three or more windings, it shall have a set operate value that will permit the transformer to carry its rated load. Locating phase overcurrent protections on the low voltage side of each winding will increase the sensitivity since only the full load rating of an individual winding need to be considered.

The protection functions should also have a fast definite time delayed element whose pickup can be slightly higher than either the maximum short-circuit current for an external fault or the magnetizing inrush current. The main function of such a stage is to obtain fast operations of heavy internal faults. Numerical overcurrent protections provide upgraded performance. The digital filters now remove the DC component and harmonics from the inrush current. The transient overreach of a numerical overcurrent protection function is very small. The protection functions can therefore be set more sensitive than conventional types.

When a transformer is connected to more than one source of short-circuit current, it may be necessary for at least some of the overcurrent protections to be directional to obtain good protection as well as selectivity for external faults. In some applications directional overcurrent protection functions are located on both the high voltage and low voltage sides of the transformer. Both protections are set to see into the transformer. The transient overreach is less than 10 per cent.

Directional functions can also be valuable when transformers, that are connected to only one source of short-circuit current, operate in parallel. Fast, sensitive and directional overcurrent protection functions monitoring the low voltage side, looking into the transformers will achieve selective fault clearance of the transformers.

The terminal is provided with three three-phase time overcurrent protection modules. The function measures the highest fundamental harmonic current of the phases. Each module can be configured to any side of the transformer. It is also possible to configure two or all three modules to the same side of the power transformer or to any feeder. Each overcurrent module has got two stages working independently of each other. The two stages have their own setting ranges for the start of the function. The lowset stage function can be chosen to have either independent time setting or a current depending inverse time characteristics according to IEC Normal Inverse, Very Inverse, Extremely Inverse and Long Time Inverse. The highset stage function can only have independent time delay setting.

Any of the two stages can be directional. The three-phase voltages from the same side of the power transformer have to be connected to the terminal. The directional function is achieved down to 1 % of rated voltage. Below this voltage no direction is achieved and the overcurrent protection will work either as a nondirectional function or be blocked depending on the chosen setting for this situation.

The voltage that will be used as the directional reference depends on the actually highest current of the three phase currents. If the current in phase a is highest, the reference voltage will be the phase-to-phase voltage between phase b and c. The characteristic angle of the relay (RCA) and the relay operate angle (ROA) are settable. The ROA is set symmetrically from the maximum torque angle (MTA). The RCA is set with reference to the reference voltage. The RCA is defined to be negative if MTA leads the reference voltage. Fig. 24 shows an example. The RCA is set to +30 degree leading and ROA is 90 degrees. The MTA direction represents a 60 degrees lagging fault current.

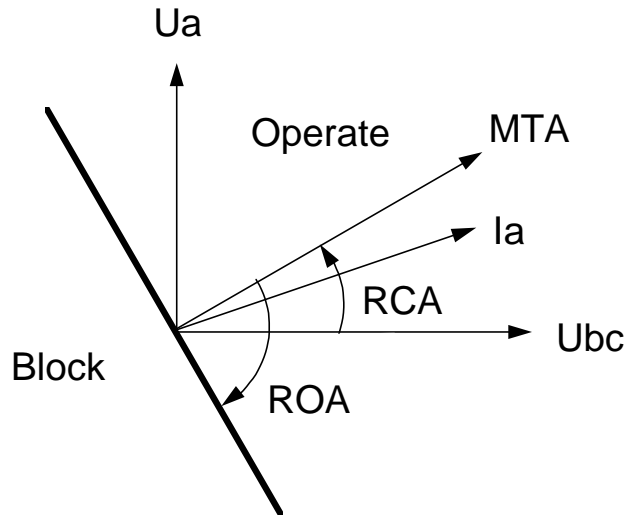


Fig. 24 Forward directional characteristic

The direction can be set to Reverse or Forward. The direction is defined to be Reverse when the protection looks into and operates for faults in the power transformer or for faults on the other side of the transformer. The direction Forward is set if the protection shall operate for faults located in the network on the same side of the transformer.

13.3

Settings

In the CAP531 configuration tool it is possible to choose UserDef side as parameter setting for SIDE2W or SIDE3W. When UserDef is chosen then the setting IrUserDef will be used as "rated" current for TOC.

For directional TOC the setting UrUserDef also have to be set. The direction for User-Def side is the same as for the primary side. Observe that for secondary and tertiary side Reverse direction means currents from power transformer and Forward direction means currents to power transformer.

The operating current is normally set in per cent of the rated load current Ir of the power transformer. However, if an overcurrent protection module is configured to another object it is possible to define another base current not related to the power transformer.

The lowset stage must be given a setting so that the highest possible load current does not cause operation. The highest possible load current of the transformer is given of the overload capacity of the transformer. The overload capacity is dependent on for example the ambient temperature and the load cycle of the transformer. Often the overload capacity of a transformer can be up to 1.4 times the rated power. The corresponding settings of the lowset stage are 130% to 170% of the overload capacity of the transformer. This setting includes a safety factor and the reset ratio of the protection. The time setting shall be coordinated with the protections of the outgoing feeders.

A power transformer can carry substantial overload during an hour or two. Many utilities want to utilize this capability temporarily. When two or more transformers are operated in parallel to share a common load, the overcurrent protection settings should consider the short time overload on one transformer upon loss of the other transformer and maybe set the operate value even higher than the recommendation above. In such a case it is recommended that the transformer is provided with a thermal overload protection.

As the overcurrent protection normally shall provide back-up protection functions for outgoing feeders, it should be checked that the overcurrent protection has the possibility to operate at minimum fault current within the back-up protection zone. The back-up function is not always possible to fulfill for example in case of a large transformer and long feeders. In such cases other measures have to be considered.

The highset stage with a short or no time delayed operation must be set so that the protection is selective to other protections in the power system. For an overcurrent protection at the high voltage side, from where the fault current is fed, it is wanted to have fast clearing of as many faults as possible within the transformer. The protection must not operate for a fault on the low voltage side busbar. The highset stage is recommended to be set at about 30 % above the maximum fault current on the low voltage side busbar. This setting includes a safety factor and the transient overreach factor of the protection. The setting should also be above the transformer inrush current. This should normally not be any problem to fulfill. However, if problems with inrush should arise there is also a possibility to use the inrush block signals from the differential protection function to block the phase overcurrent function.

With this setting fast tripping is only obtained for severe faults on the feeding side of the transformer. The protection operates delayed for faults on the remaining parts of the winding and for faults on the load side of the transformer if the fault current and the duration exceed the set value of the protection.

The highset stage of an overcurrent protection at the low voltage side must be time delayed to prevent unwanted tripping of the transformer in case of faults on the outgoing feeders. The current set value must be coordinated to the settings for the protections of the outgoing feeders. If the transformer is connected to more than one source of short-circuit current these restrictions are valid also for the highset stage at the high voltage side.

When the directional overcurrent function is used it is recommended to set the characteristic angle of the relay $RCA = -45$ degrees and the relay operate angle $ROA = 75$ degrees.

14

Restricted earth fault protection (REF)

Break-down of the insulation between a phase conductor and earth in an effectively or low impedance earthed power system results in a large fault current. A breakdown of the insulation between a transformer winding and the core or the tank may result in a large fault current which causes severe damage to the windings and the transformer core. A high gas pressure may developed, damaging the transformer tank.

Fast and sensitive detection of earth faults in power transformer winding can be obtained by restricted earth fault function in solidly earthed or low impedance earthed networks. Only requirement is that power transformer winding is connected to earth in the star point (in case of star connected windings) or via separate earthing transformer (in case of delta connected windings).

14.1

General

The restricted earth fault function is used as a unit protection function. It protects the power transformer winding, only against the faults involving earth. However, it should be noted that the earth faults are the most likely and common type of fault.

Overall transformer differential protection may not be sensitive enough to operate for:

- earth faults in the transformer winding when the network is earthed through an impedance
- earth faults in the transformer winding in solidly earthed network when the point of the fault is close to the winding star point

For these type of faults restricted earth fault is the fastest and the most sensitive protection for a transformer winding to have. In the same time REF is not affected, as differential protection, with the following power transformer related phenomena:

- magnetizing inrush currents
- overexcitation magnetizing currents
- on load tap changer
- external & internal phase faults which do not involve earth
- symmetrical overload conditions

Because of its properties restricted earth fault function may be used as main protection of the transformer winding for faults involving earth.

Traditionally restricted earth fault protection was based on “high impedance” differential principle. However, REF function available in RET 521 transformer protection terminal is a “low impedance” type. It can be shortly described as a earth (i.e. zero-sequence) differential function with supplementary directional check feature.

14.2

Magnitude of the earth fault current

The magnitude of the earth fault current in the transformer winding is not only controlled by the source impedance and neutral earthing impedance but also by the leakage reactance of the power transformer and the fact that the fault voltage may differ from the full system voltage according to the position of the fault in the winding.

For delta connected windings earth fault current will have its maximum value when the fault is on the winding terminal. This maximum fault current magnitude will mostly depend on the type of power network earthing. The minimum earth fault current, for delta connected windings, will appear for the fault in the midpoint of the winding. This fault current will be approximately 50% of the maximum earth fault current.

For solidly earthed, star connected windings earth fault current will have its maximum value when fault is on the winding terminal. The fault current will remain quite large for faults down to few percent off the transformer neutral, but fault current distribution will very much depend on the point of the fault. As the fault point moves closer to the star point, fault current contribution from the power system will be smaller, but the neutral current will be all the time quite large.

For low impedance earthed, star connected windings earth fault current will have its maximum value when the fault is on the winding terminal. This maximum fault current will be limited by the earthing impedance. The earth fault current will be almost zero for fault close to the star point. For faults in between the fault current will be directly proportional to the position of the fault in the winding.

14.3

Earth Fault current distribution

To successfully detect earth faults in earthed Y-connected or D-connected transformer windings the REF function shall discriminate between internal and external earth faults to the protected zone. REF function in RET 521 do this in two different ways:

- by diff-bias operating characteristics
- by the directional element

Earth fault current distribution in case of star connected windings for internal and external fault are shown in Fig. 25 and Fig. 26 respectively.

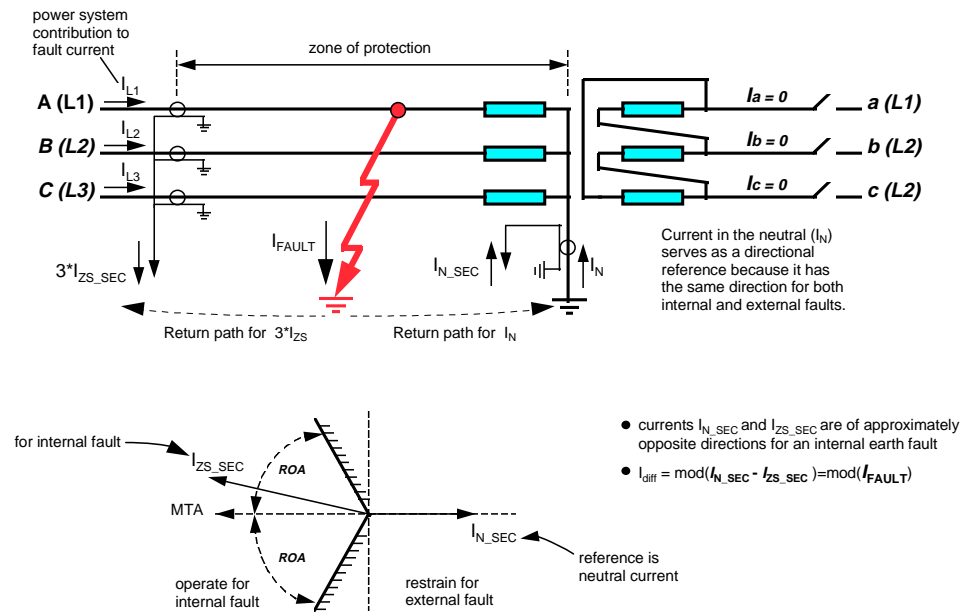


Fig. 25 Internal Earth Fault

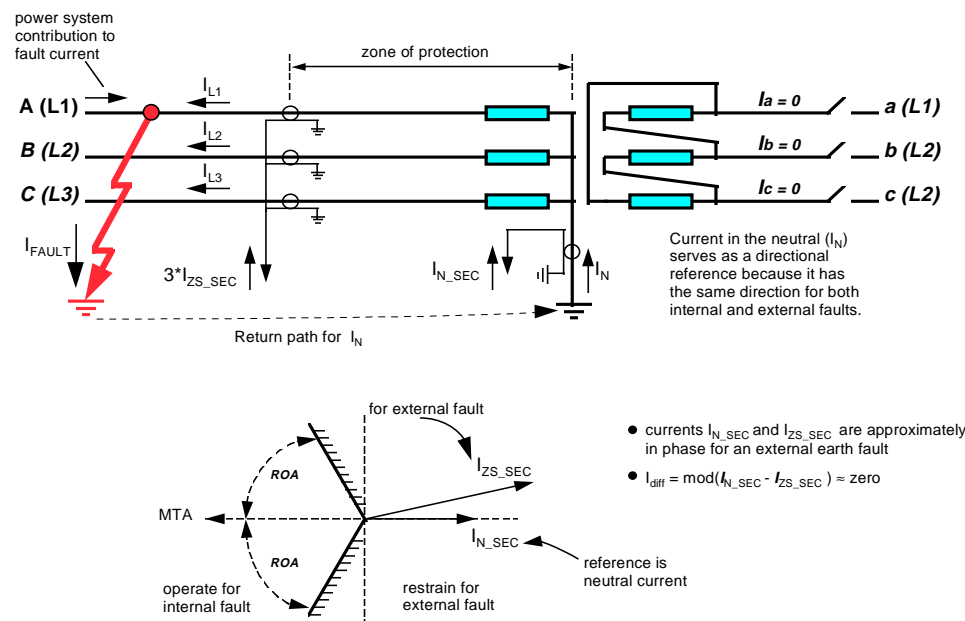


Fig. 26 External Earth Fault

As all differential protection, REF calculates the differential and the bias currents. The differential current is equal to the vectorial difference between the neutral current and residual current at the transformer winding terminal. The bias current is calculated as the relatively highest of the four currents used by REF function (i.e. three phase currents and one neutral current). If protected winding has “T” configuration (i.e. one-and-a-half breaker station) than bias current is calculated as the relatively highest of the seven currents used by REF function (i.e. two sets of three phase currents and one neutral current).

The REF has only one operate-bias characteristic which is shown in Fig. 27. By changing the minimum base sensitivity, REF bias characteristic is moved in the operating plain. First and second slopes are fixed to 70% and 100% respectively. First break point corresponds to a bias current of 1,25 pu. Second break point corresponds to a bias current for which the required differential current for REF function operation is 1,0pu.

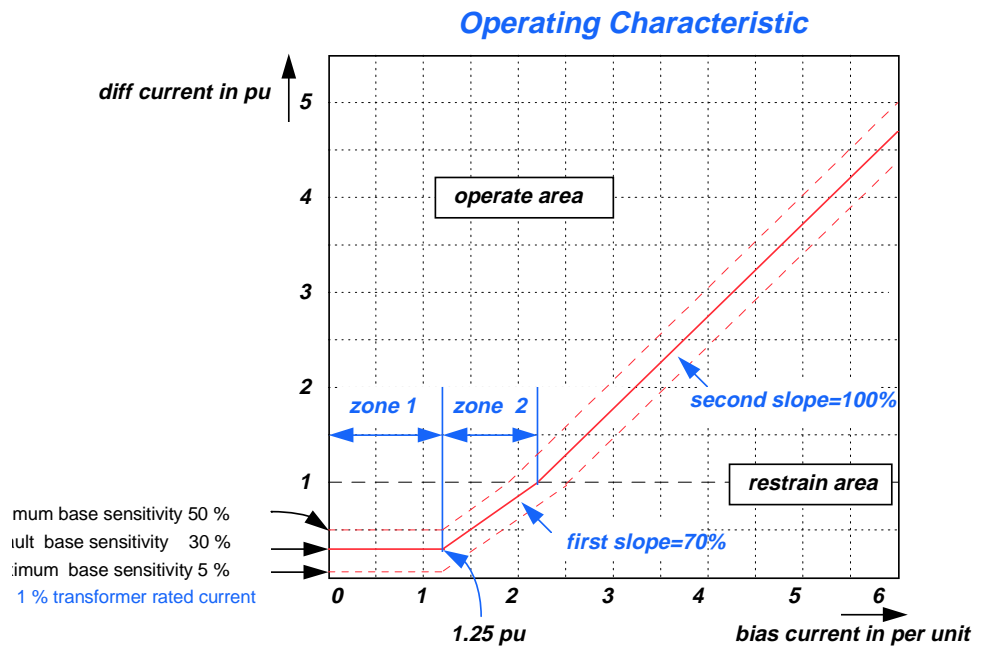


Fig. 27 Operate - bias characteristic of the restricted earth fault protection REF.

Differential and bias current from REF function are available as service values.

Additional directional criteria in REF function is pre-set to operate only for internal earth faults (See Fig. 25 and Fig. 26 for more details). However, it should be noted that is extremely important to properly set phase and neutral CT earthings (i.e. parameter “CTearth”) to enable REF directional criteria to work properly. All CT settings can be found under “Configuration” menu on built in HMI and in SMS.

14.4 Measured Quantities

REF is usually configured to measure one neutral current and one three phase set of currents. If protected winding has “T” configuration (i.e. one-and-a-half breaker station) than REF should be configured to measure one neutral current and two sets of three phase currents.

14.5 Settings

The REF is a unit protection and it is based on zero sequence currents, which only exist in case of an earth fault. Therefore the REF can be made very sensitive because no load currents need to be considered. For each REF instance there is only three settings.

Parameter “Operation” sets the REF function ON or OFF. The parameter “Idmin” defines the operating characteristic of the REF function. It is set as percentage of the rated current of the protected winding. It is therefore very important to properly set rated winding current. The parameter “roa” defines the operate area for the directional criteria.

It is recommended to set Idmin to 30% when solidly earthed power transformer windings should be protected. For low impedance earthed winding it should be set to on third of the value of the maximum earth fault current for delta connected windings and to 5% to 10% in case of star connected windings.

15 Earth fault time current protection (TEF)

15.1 General

Break-down of the insulation between a phase conductor and earth in an effectively or low impedance earthed system results in a large fault current. A breakdown of the insulation between a transformer winding and the core or the tank may result in a large fault current which causes severe damage to the windings and the transformer core. Furthermore, a high gas pressure may develop, damaging the transformer tank.

The magnitude of the winding fault current depends both on the earth-fault level, the connection group of the transformer and the location of the fault.

A sensitive earth-fault current protection, measuring the residual current ($3I_0$) in the connection between the power transformer windings and the bus and the current between YN-connected winding neutrals and earth will detect earth-faults both on the phase conductors and a large part of the windings. The coverage depends on the earthing of the system and also the connection diagram of the power transformer.

When used for protection of the power transformer circuits, input currents used for the earth-fault protection function in the terminal are either:

- measured residual current or calculated residual current from current transformers in the connection between the power transformer and bus.
- the measured current in the connection between the neutral point of a winding and earth.

The earth-fault current protection function in RET 521 can also be used for other feeders connected to the transformer bus. Input current will then be the measured or calculated residual current in the actual feeder. Another possible application is to use TEF as a tank protection.

Measured residual current is obtained by summation of the secondary phase currents from the current transformer group or from one current transformer encompassing all three phase conductors. The residual current can also be obtained by summing up the three phase current vectors mathematically.

The residual current $3I_0$ gives rise to a residual voltage $3U_0$. The residual voltage can be measured using

- a single voltage input from the open delta windings of a three-phase voltage transformer group
- a single voltage input from a voltage transformer connected between the neutral point of a winding and earth in a high impedance earthed or unearthened network. Note that the input voltage in this case will be $1 \times U_0$!
- a three-phase voltage input and summing up the three phase voltage vectors internally

The current lags the voltage $-3U_0$ by a phase angle that is equal to the angle of the zero-sequence source impedance. An example is shown in Fig. 29, where the residual current flowing towards the faulted power transformer lags the voltage U_A with a phase angle equal to the impedance angle of the source impedance Z_{OA} .

Directional function and hence selectivity for internal and external faults can be obtained by measuring the angle between the residual current and voltage.

Residual currents due to imbalance in the network can appear in the circuits of a winding with neutral connected to earth.

The magnetizing inrush current can contain a large dc component and the magnitude is generally different in the three phases. A false residual current can result due to different saturation of the line current transformer cores. If the power transformer winding neutral is earthed, the magnetising inrush current can have a residual current component which is measured both in the neutral connection to earth and by the line current transformers. To prevent an unwanted operation, a second harmonic current blocking function is therefore available in the earth-fault current protection.

15.2

Direction and magnitude of the fault current

15.2.1

Earth-faults on a phase conductor

Earth-fault current can only flow from a part of the network which is connected to earth. Any appreciable earth fault current can only flow towards the Y- and delta windings connected to bus B respectively C in Fig. 28. In case of an external fault, only a small capacitive earth-fault current will flow from the winding towards the fault.

Hence, an earth-fault relay connected to the current transformer groups b) or c) in Fig. 28 will be selective and only operate in case of internal faults.

In case of an earth-fault in network A, part of the fault current will flow via the neutral connection of the YN-connected winding and out towards the fault. Hence, an earth-fault relay connected to current transformer group a) must be directional if selective function for internal or external earth-fault is requested.

A relay measuring the current in the connection between the winding neutral and earth can not be selective, since the fault current flows in the same direction for faults in the transformer and faults in the network, compare Fig. 25 and Fig. 26.

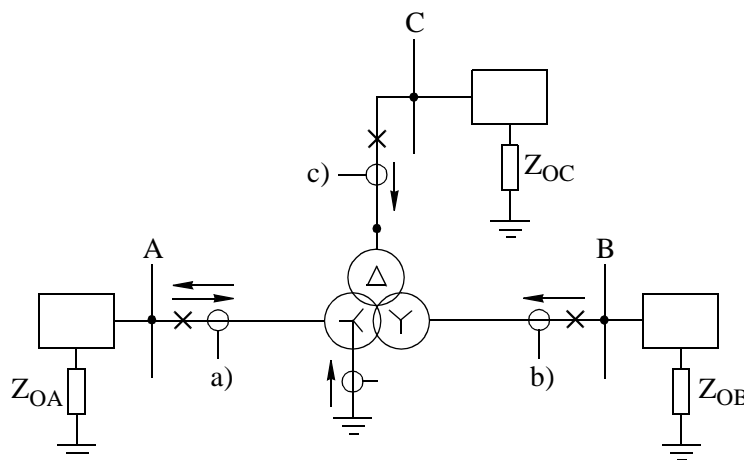


Fig. 28 Three-winding transformer with connected networks

If the positive and negative sequence impedances can be assumed equal, which normally is the case for faults in the network, the single-phase fault current can be calculated from the formula:

$$IF = \frac{3U_{ph}}{2Z_s + Z_o + 3R_f}$$

where:

- U_{ph} = phase voltage
- R_f = fault resistance in ohms
- Z_o = zero-sequence source impedance of the faulted network in ohms per phase
- Z_s = 3-phase short circuit impedance in ohms per phase at the faulted spot
- When the 3-phase short-circuit current (I_{sc}) or the fault level MVA (S) is known, Z_s is calculated from the formula:

$$Z_s = \frac{U_{ph}}{I_{sc}} = \frac{U^2}{S}$$

where U = rated voltage between phases (kV).

For a fault close to buses B or C in Fig. 28, $Z_o = Z_{oB}$ respectively Z_{oC} .

For a fault close to bus A, Z_o is equal to the impedance of the parallel connected zero-sequence impedances Z_{oT} of the transformer and the source impedance Z_{oA} of network A when the transformer is disconnected.

$$Z_o = \frac{Z_{oA} \times Z_{oT}}{Z_{oA} + Z_{oT}}$$

The residual fault current IFA flowing from bus A towards the transformer is calculated from the formula:

$$IFA = IF \times \frac{Z_{oT}}{Z_{oA} + Z_{oT}}$$

For the transformer in Fig. 28, with the neutral directly connected to earth, the impedance Z_{oT} on the transformer side is equal to the zero-sequence impedance X_{oT} of the transformer winding. If an earthing impedance Z_n is connected between the winding neutral and earth, the zero sequence impedance $Z_{oT} = X_{oT} + 3 \times Z_n$.

The residual fault current flowing from the bus towards the transformer in case of a transformer fault is lagging the voltage $-3U_o$ by an angle equal to the impedance angle of the source impedance of the network (For example impedance angle of Z_{oA} for a relay connected to current transformers a) in Fig. 28).

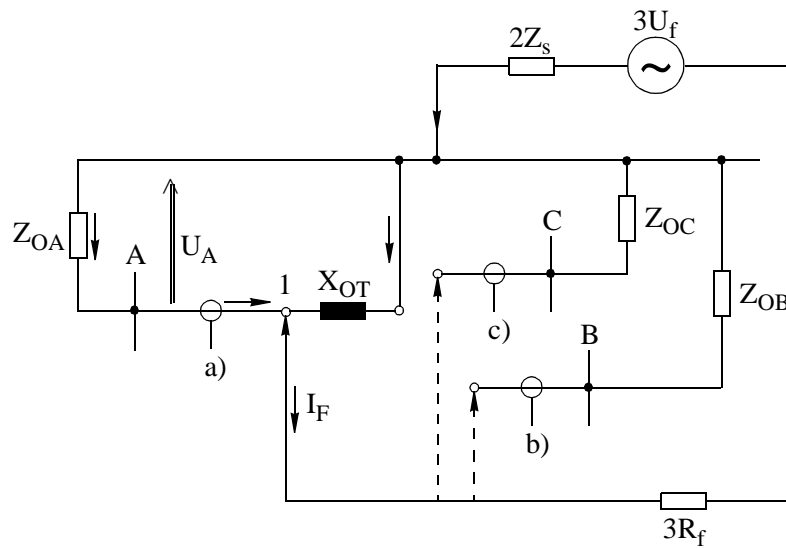
The residual fault current flowing from the transformer towards the bus in case of an external fault is calculated from the equation

$$IFF = IF \times \frac{Z_{oA}}{Z_{oA} + Z_{oT}}$$

The residual fault current flowing towards the bus is lagging the voltage $-3U_o$ with an angle equal to the impedance angle of the zero-sequence impedance Z_{oT} on the transformer side.

Fig. 29 shows the simplified diagram with the zero-sequence impedance diagram of the 3-winding transformer according to Fig. 28. The full lines show the connection when calculating the current for a fault on a terminal of the Yo-connected winding. The dotted lines indicate the corresponding connection when calculating faults on the terminal of the Y resp. delta windings.

For further details, see standard zero-sequence impedance diagrams for power transformers.



$$U_0 = -I_0 \times Z_0 I_F = 3 \times I_0 Z_0 = Z_{0A} \times X_{OT} / Z_{0A} + X_{OT} \text{ Hence } U_A = -3U_0$$

Fig. 29 Simplified circuits for calculation of residual fault currents

15.2.2 Earth-faults in transformer windings

15.2.2.1 Faults in delta connected windings

An earth-fault at the midpoint of one phase winding gives the minimum fault current, approximately 50 % of the fault current resulting from an earth-fault on the phase conductor. The fault current increases gradually when the fault is moved towards the end of the winding. Hence, the entire winding can normally be protected.

15.2.2.2 Faults in Y-connected windings (neutral not earthed)

A winding earth-fault, close to the terminal, results in a voltage per turn far beyond the core saturation level for the part of the winding between the terminal and the fault. The magnitude of the fault current will be approximately the same as for an earth-fault on the phase conductor. The magnetizing current will normally contain a basic frequency component of more than 70 %.

If the transformer also has a delta- or a YN-connected winding with direct earthed neutral in a solidly earthed system, a fault current of about 10 % of the phase conductor fault current can be expected for a fault 20 % off the neutral. However, if the transformer has no delta- or YN-connected winding, the earth fault current will decrease and can be expected to be about 10 % of the phase conductor fault current for a fault 50 % off the neutral.

The magnitude of the winding fault current can vary substantially from the stated figures depending on the magnetising characteristics of the power transformer and other design factors.

15.2.2.3**Faults in windings (neutral earthed)**

The fault current will have its maximum value when the fault is on the winding terminal. The fault current remains quite large for faults down to some few per cent off the transformer neutral, but the part of the fault current seen by a residually connected earth-fault relay decreases when the fault moves towards the neutral point of the winding. A relay measuring the current in the connection between the neutral point and earth will see practically all the fault current when the fault is close to the neutral point. This relay, however, must normally have a long time delay to be selective against other earth-fault relays in the network.

The best coverage will be achieved by the restricted earth-fault scheme.

15.3**Measured quantities**

All three earth-fault time current functions in RET 521 can be configured to any single-phase or 3-phase current input. The directional function can be configured to any single-phase or 3-phase voltage input. The protection uses the fundamental frequency component of the currents and voltages.

When connected to a 3-phase input, the residual current or voltage is calculated mathematically within RET 521.

15.4**Settings**

In the CAP531 it is possible to choose UserDef side as parameter setting for SIDE2W or SIDE3W. When UserDef is chosen then the setting IrUserDef will be used as "rated" current for TEF.

For directional TEF the setting UrUserDef also has to be set. The direction for UserDef side is the same as for the primary side. Observe that for secondary and tertiary side Reverse direction means currents from power transformer and Forward direction means currents to power transformer.

15.4.1**Delta connected windings**

The high set stage, set to 1/3 of minimum fault current for an earth fault on the winding terminal will protect the phase conductors between the current transformers and the winding and also the entire winding.

A low set stage, with setting 10 % of minimum fault current for an earth fault on the winding terminal, can be used to detect developing faults. A long inverse time delay is recommended.

Second harmonic blocking, with typical setting 20 % second harmonic to first harmonic ratio should be selected for both stages if the winding is connected to a network with power generation.

15.4.2**Y-connected windings**

With the same settings as for delta windings according to above, the high current stage will normally cover more than 50 % of the winding and the low set stage will normally cover about 80 % of the winding if the power transformer also has a delta-connected or direct earthed YN-connected winding.

For a YY-connected transformer, about 50 % of the winding will normally be protected.

Second harmonic blocking, with typical setting 20 % second harmonic to first harmonic ratio should be selected for both stages if the winding is connected to a network with power generation.

15.4.3**Y0-connected windings**

Residual currents flowing in the winding circuits due to imbalance in the network must be taken into consideration when setting the protection.

Directional function should be selected when the relay is connected to residually connected current transformers between the bus and the winding.

When directional setting “Forward” is selected, the relay operates for faults in the network. The current and time delay settings must be coordinated with the setting of other earth-fault relays in the network. The characteristic angle (rca) is set to match the impedance angle of the zero-sequence impedance X_{0T} of the transformer if the winding neutral is direct earthed. If an earthing impedance Z_n is inserted between the neutral and earth, the characteristic angle is set to match the impedance angle of $X_{0T} + 3 \times Z_n$.

Due to the bandpass filtering, a polarising voltage down to 1 per cent of the rated voltage will provide correct directional operation. This is also valid when the protection is connected to capacitive voltage transformers.

The minimum polarising voltage to the protection is calculated from the formula

$$U_{min} = IF_{min} \times Z_0 \times \frac{U_{sec}}{U_{prim}}$$

where:

- IF_{min} = minimum primary fault current
- Z_0 = Zero-sequence impedance of network
- U_{sec} , U_{prim} = rated phase voltages of the open delta-connected voltage transformers.

The rated transformer phase-to phase voltage is seen as 100 % of U_r .

Directional setting “Reverse” is used when the protection shall operate for faults in the transformer. The characteristic angle (rca) is set to match the impedance angle of the zero-sequence source impedance of the network (For example the characteristic angle of impedance ZoA when connected to current transformers a) in Fig. 29).

As a non-directional protection function, measuring the current in the connection between the neutral point and earth, the time/current settings must be coordinated with the other earth-fault relays in the network.

15.4.4**External feeders**

When used as earth-fault current protection in other feeders connected to the transformer bus, the time/current settings must be coordinated with the setting of the other relays in the network.

16**Single/three-phase time overvoltage protection (TOV)****16.1****General****16.1.1****Phase overvoltage**

The overvoltage protection is applied on power system elements, such as generators, transformers, motors and power lines in order to prevent excessive voltages that can damage the insulation. Overvoltage at network frequency may also cause damage to power transformers and electric machines due to overfluxing.

Overvoltage at or close to power system frequency can occur as a result of:

- 1 Incorrect operation of a voltage regulator or wrong settings under manual voltage control
- 2 Sudden loss of load, e.g. disconnection of a heavily loaded power line
- 3 Low active load in transmission systems with lines with large capacitance to earth.
- 4 Overspeed of generator when disconnected from the network and incorrect operation of the machine AVR
- 5 Phase to earth faults in unearthed or high impedance earthed systems

Overvoltages in the form of transients can also occur in the network. Protection against transient voltages is basically provided by surge arrestors connected to incoming lines and busbars.

16.1.2**Residual voltage**

Earth fault in the network results in a residual voltage $3U_0$ which can be measured by summing up the three phase voltages vectorially:

$$3U_o = U_{L1} + U_{L2} + U_{L3}$$

The residual voltage can be measured using:

- a single voltage input from the broken secondary windings of a three-phase voltage transformer group.
- a single voltage input from a voltage transformer connected between the neutral point of a winding and earth in a high impedance earthed or unearthed network. Note that the input voltage in this case will be $1 \times U_o$!
- a three-phase voltage input and summing up the three phase voltage vectors mathematically.

The residual voltage is transferred to all parts of the network which are galvanically interconnected with the faulted spot. It is also transmitted through power transformers with two Y-connected windings with the neutrals connected to earth, and, to a small extent, through the capacitances between the high and low voltage windings of power transformers.

The residual voltage is highest at the faulted spot. In a high impedance earthed system, most of the voltage is generated across the earthing impedance, and the residual voltage will be approximately the same in the whole network. If the system is solidly earthed, the residual voltage is reduced towards the source (earthing point).

A residual voltage, normally limited to some few per cent of rated phase voltage, can be present under normal service conditions due to imbalances in the network.

The TOV protection is generally used as a backup function for the selective earth-fault protections in a network.

16.1.2.1

Magnitude of the residual fault voltage

If the positive and negative sequence impedances can be assumed equal, which normally is the case for faults in the network, the residual voltage in case of a single-phase earth-fault can be calculated from the formula:

$$3U_o = \frac{3U_{ph} \times Z_o}{2Z_s + Z_o + 3R_f}$$

where:

- U_{ph} = phase voltage
- R_f = fault resistance in ohms
- Z_o = zero-sequence impedance in ohms per phase at the faulted spot.
- Z_s = 3-phase short circuit impedance in ohms per phase at the faulted spot

When the 3-phase short-circuit current (I_{sc}) or the fault level MVA (S) is known, Z_s is calculated from the formula:

$$Z_s = \frac{U_{ph}}{I_{sc}} = \frac{U^2}{S}$$

where U = rated voltage between phases (kV).

If the positive and negative impedances are assumed equal, the residual voltage in case of a phase-phase-earth fault without fault resistance can be calculated from the formula:

$$3U_o = \frac{3U_{ph} \times Z_o}{Z_s + 2Z_o}$$

For this type of fault, the residual voltage rapidly decreases when the fault resistance between phases and earth increases.

Generally, the function of the neutral point voltage protection in case of single-phase earth faults is considered when determining the settings. Two-phase faults with connection to earth will be detected by the phase short-circuit protection.

16.2

Measured quantities

The time overvoltage protection TOV can be configured to any three-phase or single-phase voltage input. It calculates the fundamental frequency component of the voltage.

With Function Selector setting 1 = SU for single-phase voltage input, the TOV protection is normally used to measure a phase-to-phase voltage or the residual voltage (neutral voltage protection).

The three-phase voltage input function can be set to measure the phase-to-earth voltages or the residual voltage $3U_o$. The selection is made with the CAP 531 configuration tool, with Function Selector setting 2 = G3U for measuring the phase-to-earth voltages. Setting 3 = G3URES is used for measuring the residual voltage $3U_o$ when TOV is used as an earth-fault protection.

16.3

Settings

The TOV protection has two voltage stages, the low set stage and the high set stage. Definite time or very inverse time delay can be selected for the low set stage. The high set stage has a definite time delay.

The operate voltage of the TOV protection is set in per cent of the rated phase-to-phase voltage of the transformer winding. The operate voltage on the relay terminals is equal to the set primary voltage multiplied by the set ratio of the voltage transformers.

16.3.1**Settings for phase overvoltage protection**

The low set voltage stage is normally, with some margin, set higher than maximum voltage under service conditions and with sufficient time delay to override transient overvoltages. The high voltage stage with short time delay can be set slightly higher than transient overvoltages due to load rejection etc.

16.3.2**Settings for neutral voltage protection**

The operate value of the neutral time voltage function must - with a margin - be set higher than the maximum residual voltage to the protection when there is no fault in the network. The time/voltage settings must be coordinated with the setting of other earth-fault relays in the network.

The minimum residual voltage to the protection in case of a single-phase earth fault is calculated from the formula:

$$U_{min} = IF_{min} \times Z_0 \frac{U_{sec}}{U_{prim}}$$

where:

- IF_{min} = minimum primary earth fault current.
- U_{sec} , U_{prim} = rated phase voltages of the open delta-connected voltage transformers.
- Z_0 = zero sequence impedance at the faulted spot

16.3.3**Setting example:**

Rated voltage of the transformer winding: 10 kV

Rated VT ratio:

$$\frac{11}{\sqrt{3}} / \frac{0,11}{\sqrt{3}} / \frac{0,11}{3}$$

16.3.3.1**Phase overvoltage protection**

Assume that stage UsetLow shall be set to operate at 120 % of rated transformer voltage.

1) Settings for three-phase voltage input:

Function Selector 2=G3U

$V_{Tprim} = 11,0 \text{ kV}$ $V_{Tsec} = 110 \text{ V}$

$U_{set \text{ Low}} = 120/\sqrt{3} = 69 \text{ \%}$.

The operate phase-to-earth voltage on the relay terminal is equal to $10\,000 \times 0,11/11 \times 69/100 = 69 \text{ V}$.

2) Settings for single input of phase-to-phase voltage:

Function Selector 1=SU

$V_{Tprim} = 11,0 \text{ kV}$ $V_{Tsec} = 110 \text{ V}$

$U_{set \text{ Low}} = 120 \text{ \%}$.

The operate phase-to-phase voltage on the relay input terminal is equal to $10\,000 \times 0,11/11 \times 120/100 = 120 \text{ V}$

16.3.3.2

Using TOV as a neutral voltage protection

Assume setting $U_{setLow} =$ neutral point voltage $U_0 = 10 \text{ \%}$ of rated phase voltage of the transformer winding.

1) With 3-phase voltage input and Function Selector setting 3=G3URES, the protection measures the voltage $3U_0$. Settings:

$V_{Tprim} = 11,0 \text{ kV}$ $V_{Tsec} = 110 \text{ V}$

$U_{setLow} = 10/\sqrt{3} \times 3 = 17 \text{ \%}$

The operate voltage on the relay side, measured by injection between one phase terminal and neutral, is

$10\,000 \times 0,11/11 \times 17/100 = 17 \text{ V}$.

2) Single voltage input from the broken delta windings with rated secondary voltage $110/3 \text{ V}$. The input voltage to the protection is $3U_0$ and the setting becomes

Function Selector 1=SU

$V_{Tprim} = 11,0 \text{ kV}$ $V_{Tsec} = 63 \text{ V}$ (see Note below)

$U_{setLow} = 10/\sqrt{3} \times 3 = 17 \text{ \%}$ like above.

Note: The VT transformer ratio for the broken delta windings must be correctly set. The set values in RET 521 are primary and secondary phase-to-phase voltages in a 3-phase system. In the example above, the VT ratio of the broken delta windings is set as $VT_{prim} = 11 \text{ kV}$ and $VT_{sec} = 110 \times \sqrt{3}/3 = 63 \text{ V}$.

The operate voltage, measured on the relay terminals, is

$$10\,000 \times 0,063/11 \times 17/100 = 9,7 \text{ V.}$$

3) Single-phase input from VT with ratio 11/0,11 kV connected between transformer neutral and earth. The input voltage to the protection is $1 \times U_0$, and the setting becomes

Function Selector 1=SU

$$VT_{prim} = 11,0 \text{ kV } VT_{sec} = 110 \text{ V}$$

$$U_{setLow} = 10/\sqrt{3} = 6 \text{ \%}.$$

The operate voltage, measured on the relay terminals is

$$10\,000 \times 0,11/11 \times 6/100 = 6 \text{ V.}$$

17

Single/three-phase time undervoltage protection (TUV)

17.1

General

The undervoltage protection is applied on power system elements, such as generators, transformers, motors and power lines in order to detect low voltage conditions.

Low voltage conditions are caused by abnormal operation or fault in the power system.

The undervoltage protection can be used in combination with overcurrent protections, either as restraint or in logic “and gates” of the trip signals issued by the two functions. Other applications are the detection of “no voltage” condition, e.g. before the energisation of a HV line or for automatic breaker trip in case of a blackout.

The undervoltage protection is also used to initiate voltage correction measures, like insertion of shunt capacitor batteries to compensate for reactive load and thereby increasing the voltage. The undervoltage protection can be used to disconnect from the network apparatuses, like electric motors, which will be damaged when subject to service under low voltage conditions, .

The time undervoltage protection TUV deals with low voltage conditions at power system frequency, which can depend on:

- 1 Malfunctioning of a voltage regulator or wrong settings under manual control.
- 2 Overload.
- 3 Short circuits, often as phase to earth faults (unsymmetrical voltage decrease).

1 and 2 cause symmetrical voltage decrease.

17.2

Measured quantities

The time undervoltage protection TUV protection can be configured to any three-phase or single-phase voltage input. It calculates the fundamental frequency component of the voltage.

The three-phase undervoltage function calculates the three phase-to-earth voltages. With the CAP531 configuration tool one can select whether one phase voltage below set operating value is sufficient for tripping or if all three phase voltages need be below set value.

When tripping for one phase below set value is selected, the undervoltage protection can also detect earth faults.

When single-phase voltage input is used, the phase-to-phase application is somehow limited; only symmetrical voltage drops can certainly be detected. An earth fault in an unearthed or high impedance earthed system will not be seen by the protection.

The same applies to the phase-to-earth measuring version which can only detect a voltage drop in the monitored phase; this last version is used in special applications.

17.3

Settings

The operate voltage of the TUV protection is set in per cent of the rated phase-to-phase voltage of the transformer winding. The operate voltage on the relay terminals is equal to the set primary voltage multiplied by the set ratio of the voltage transformers.

When using the three-phase voltage input, the setting figure must take into consideration that the operate phase-to-earth voltage is set in per cent of the phase-to-phase voltage.

The TUV function has two independent voltage stages, a high set stage and a low set stage. Both stages have definite time delay.

17.3.1**Setting example**

Assume:

- Rated voltage of transformer winding: 10 kV
- Rated VT ratio: 11/0,11

Assume that stage UsetHigh shall be set to operate at 80 % of rated transformer voltage.

1 Settings for single input of phase-to-phase voltage:

- Function Selector 1=SU
- VTprim = 11,0 kV VTsec = 110V
- UsetLow = 80 %
- The operate phase-to-phase voltage on the relay input terminal is equal to

$$10000 \times \frac{0.11}{11} \times \frac{80}{100} = 80 \text{ V} .$$

2 Settings for three-phase voltage input:

- Function Selector 2=G3U
- VTprim = 11,0 kV
- VTsec = 110V
- UsetLow = $\frac{80}{\sqrt{3}} = 46\%$
- The operate phase-to-neutral voltage on the relay terminal is equal to

$$10000 \times \frac{0.11}{11} \times \frac{46}{100} = 69 \text{ V} .$$

18**Thermal overload protection (THOL)****18.1****General**

The insulating material surrounding the phase current conductors in transformers, reactors, cables and other electrical equipment ages too rapidly if the temperature exceeds the design limit value.

All electrical conductors have a certain resistance, and the active power loss I^2R gives rise to a temperature increase which is proportional to the square of the current. Heat energy is carried off in proportion to the temperature difference between the conductor and the surrounding material and the temperature increase of the conductor can be defined as a function of time by the so called thermal time constant T , as shown in Fig. 30.

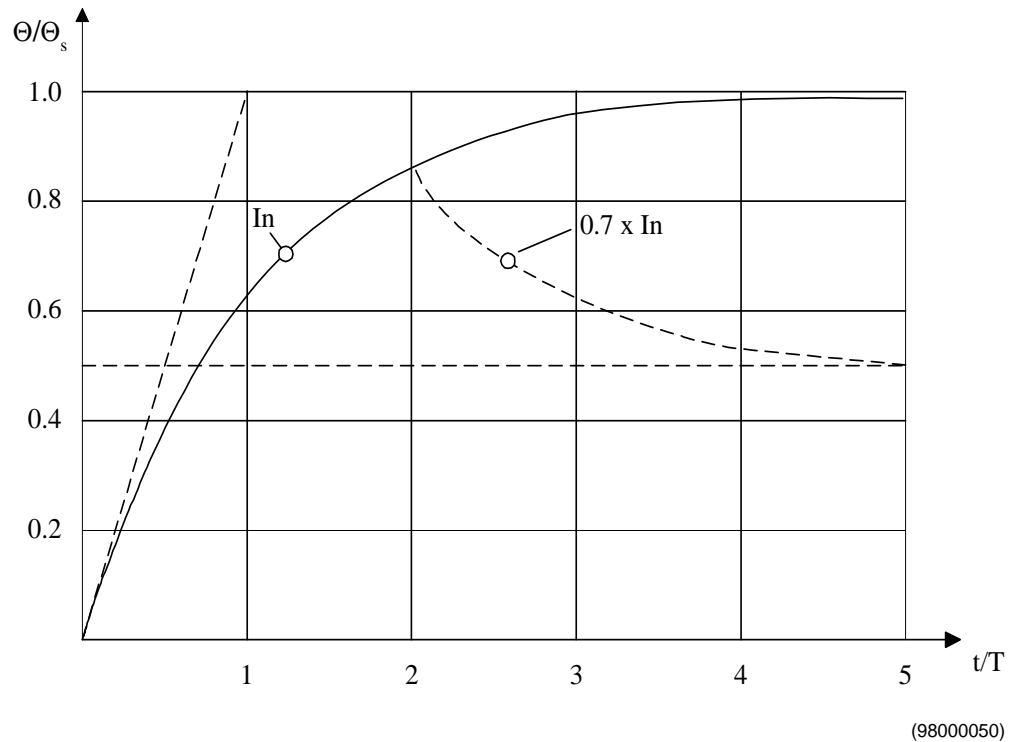


Fig. 30 Temperature rise as function of time

After a time equal to T , the temperature increase has reached 63 % of the final value. Since the increase is proportional to the square of the current, a current equal to $1,26 \times$ rated value will after time T give a temperature increase equal to the rated final temperature increase ($1,26^2 \times 0,63 = 1$) and the final temperature rise will be $1,26^2 = 1,6$ times rated value.

After a time equal to $4 \times T$, the temperature increase is about 98 % of the final value.

If the current is reduced, the temperature decreases exponentially towards the new steady state value. The dotted line in Fig. 30 shows how the temperature decreases towards $0,7^2 = 0,49$ times rated temperature increase when the current after a time equal to $2 \times T$ is reduced from 100% to 70 % of rated value. The time constant T remains unaltered as long as the cooling is unaltered.

Power transformers and cables are often required to permit short-time overloads up to 1,5 x rated current. The phase short-circuit overcurrent relays will normally be set with an operating value far too high to provide any thermal protection.

Temperature and overload monitoring of oil-filled transformers is carried out with indicating thermostats which are standard accessories. The oil thermometer, which measures the top oil temperature, can not be relied upon to detect short-time overloads beyond permissible limits.

Large transformers often have a so-called “winding thermometer”, which measures the oil temperature and also is provided with a heater element fed from the load current. This device provides a good monitoring of the temperature of the winding.

Transformers without “winding thermometer” should have a thermal current protection with an operating current/time characteristic that corresponds to the current overload characteristic of the transformer windings. For transformers with “winding thermometer”, a thermal current protection will provide a back-up function for this monitoring device.

A power transformer can have two different MVA ratings, one basic rating and one higher rating with forced cooling. The thermal current function in RET521 therefore has two different load current and thermal time constant settings. The high current setting is activated by activating a binary input on the protection.

The thermal current protection function can also be used to protect feeder cables connected to the transformer.

Electrical cables which can be loaded up to the permissible thermal load current should be provided with both thermal and short-circuit protection. The thermal time constant is normally shorter for cables surrounded by air than for cables placed in the ground. This should be taken into consideration if part of the cable is surrounded by air.

18.2

Measured quantities

The thermal overload function can be configured to any 3-phase current input. It uses the fundamental frequency component of the largest of the three phase currents.

18.3

Fault conditions

A short-time increment of the load current beyond maximum permitted continuous value is not a fault condition as such. It is, however, a condition which must be detected and action must be taken before it results in thermal damages.

18.4**Settings**

The thermal overcurrent function in RET521 has time-current characteristics which follows the equation:

$$t = T \times \ln \frac{I^2 - Ip^2}{I^2 - Itr^2}$$

where:

- T= thermal time constant
- I = overload current
- Ip= current previous to the overload, assuming sufficient long time to reach steady-state temperature
- Itr = thermal overload steady state trip current

The thermal protection has two current stages with settable time constant:

- normal base current Ib1, set in per cent of rated current Ir, with Time Constant1
- base current Ib2, set in per cent of rated current Ir, with Time Constant2.

Current stage Ib2 is activated and replaces stage Ib1 when the assigned binary input signal is activated. The thermal characteristics of the protection is then adapted to the conditions set to correspond to forced cooling. The thermal content in per cent of the operate value is kept unchanged when switching over between the stages.

The trip level is determined by the setting of the steady state trip current Itr. The setting is made in per cent of the set base current and the percentage setting is common for both current stages.

18.4.1**Setting example**

Assume the following settings:

Stage 1: Base current Ib1= 90 % of Ir. Time Constant 1 = 10 minutes.

Stage 2: Base current Ib2 = 100 % of Ir. Time Constant 2 = 10 minutes.

Trip level current Itr = 102 % of the base currents.

Assume an overload current of 135 % of Ir, equal to $135/90 = 1,5 \times Ib1$ and $135/100 = 1,35 \times Ib2$

The operate time from cold load is for stage 1:

$$t = 10 \times \ln \frac{1,5^2}{1,5^2 - 1,02^2} = 6,2min$$

and for stage 2:

$$t = 10 \times \ln \frac{1,35^2}{1,35^2 - 1,02^2} = 8,5min$$

The value of the “preheat current” I_p must, when inserted into the above formula, be expressed as a per unit value of the base current of the actual stage.

Fig. 31 shows the current/time characteristics for currents up to 8 times the set base current when the trip current level is set to $I_{tr} = 101\%$.

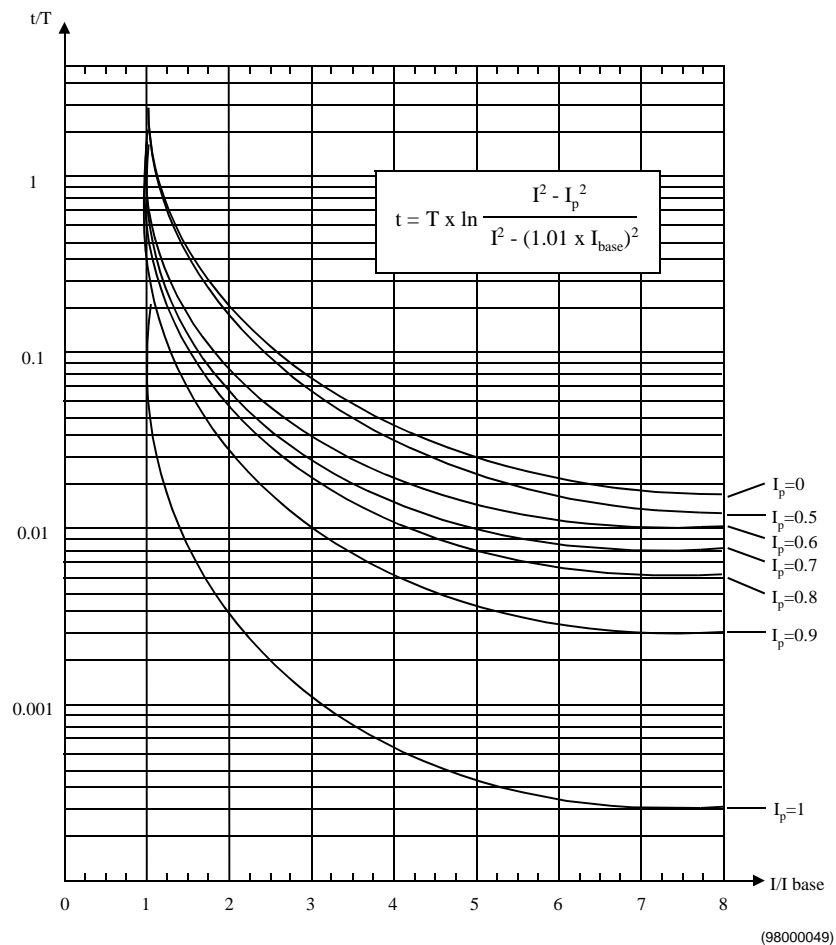


Fig. 31

Some times the time-current capability curve of the object is given instead of the thermal time constant. The time constant can then be determined using the time curves in Fig. 31. Assume, e.g. that the permissible time for 2 times rated current starting from no load is 3 minutes. From Fig. 31 it is seen that this point corresponds to 0,3 T if $I_{tr} = 101\%$ of base current. Hence, T is equal to 3 min / 0,3 = 10 minutes. If the permissible time is 0,5 min at 5 times rated current, this corresponds to 0,04 T. Hence, the time constant will be 0,5 / 0,04 = 12,5 minutes.

If different values are calculated for different points on the time-current capability curve, the shortest calculated time constant should be used for the thermal function.

The influence of the I_{tr} setting on the operate time is moderate. Settings $I_{tr} = 101\%$ gives operate time 6,0 minutes for stage 1 instead of 6,2 minutes with setting $I_{tr} = 102\%$ according to Example 1 above.

19 Overexcitation protection (OVEX)

19.1 General

When the laminated core of a power transformer is subjected to a magnetic flux density beyond the design limits, stray flux will flow into non-laminated components not designed to carry flux and cause eddy currents to flow. The eddy currents can cause excessive heating and severe damage to the insulation in adjacent parts in a relatively short time.

The general equation for the induced rms voltage in a coil:

$$E = 4,44 \times f \times A \times N \times B_{\max}$$

where:

- f = frequency (Hz)
- A = cross-sectional area of the core (square meters)
- N = number of winding turns
- B_{\max} = peak value of flux density (Tesla)

can be written $B_{\max} = K \times E / f$, where K is a constant

Hence, the flux density is proportional to the ratio between the voltage and the frequency.

Overvoltage, or underfrequency, or a combination of both, will result in an excessive flux density level, which is denominated overfluxing or over-excitation.

The overexcitation capability curve is influenced by the design of the object and it is generally different for generators and transformers.

According to the IEC standards, the power transformers shall be capable to deliver rated load current continuously at an applied voltage of 105 % of rated value (at rated frequency). For special cases, the purchaser may specify that the transformer shall be capable to operate continuously at an applied voltage 110 % of rated value at no load, reduced to 105 % at rated secondary load current.

According to ANSI/IEEE standards, the transformers shall be capable to deliver rated load current continuously at an output voltage of 105 % of rated value (at rated frequency) and operate continuously with output voltage equal to 110 % of rated value at no load.

The capability of a transformer (or generator) to withstand overexcitation can be given in the form of a thermal capability curve, i.e. a diagram which shows the permissible time as a function of the level of over-excitation.

When the transformer is loaded, the induced voltage and hence the flux density in the core can not be read off directly from the transformer terminal voltage. Normally, the leakage reactance of each separate winding is not known and the flux density in the transformer core can then not be calculated.

In two-winding transformers, the low voltage winding is normally placed close to the core and the voltage across this winding gives a good representation of the flux density in the core. However, depending on the design, the flux flowing in the yoke may be critical for the overfluxing capability of the transformer.

For power transformers with fixed direction of the load flow, the voltage to the V/Hz protection function should therefore be taken from the feeder side.

Heat accumulated in critical parts during a period of overexcitation will be reduced gradually when the excitation retains the normal value. If a new period of overexcitation occurs after a short time interval, the heating will start from a higher level. The overexcitation protection function should therefore have a thermal memory. In RET 521, the cooling time constant is settable within a wide range.

The general experience is that the overexcitation characteristics for a number of power transformers are not in accordance with standard inverse time curves. In order to make optimal settings possible, a transformer adapted characteristic is available in RET521. The operate characteristic of the protection function can be set to correspond quite well with any characteristic by setting the operate time for six different figures of over-excitation in the range from 100% to 180% of rated V/Hz.

19.2

Measured quantities

The V/Hz function can be configured to any single-phase or 3-phase voltage input and any 3-phase current input. It uses the fundamental frequency component of current and voltages.

When configured to a single phase-to-phase voltage input, a single-phase current is calculated which has the same phase angle relative the phase-to-phase voltage as the phase currents have relative the phase voltages in a symmetrical system.

The function should in the first place be configured to a 3-phase voltage input if available. It then uses the positive sequence quantities of voltages and currents.

It should be noted that analogue measurements should not be taken from any winding where OLTC is located

19.3**Fault conditions**

The greatest risk for overexcitation exists in a thermal power station when the generator-transformer block is disconnected from the rest of the network. Overexcitation can occur during start-up and shut-down of the generator if the field current is not properly adjusted. Loss-of load or load-shedding can also result in overexcitation if the voltage control is not functioning properly.

Loss of load or load-shedding at a transformer substation can result in overexcitation if the voltage control is insufficient or out of order.

Low frequency in a system isolated from the main network can result in overexcitation if the voltage regulating system maintains normal voltage.

19.4**Settings**

Sufficient information about the overexcitation capability of the protected object(s) must be available when making the settings. The most complete information is given in an overexcitation capability diagram like Fig. 32.

The settings E_{max} and $E_{maxcount}$ are made in per unit of the rated voltage of the transformer winding at rated frequency.

19.4.1**Setting example**

Set the transformer adapted curve for a transformer with over-excitation characteristics in according to Fig. 32.

$E_{maxcont}$ for the protection is set equal to the permissible continuous overexcitation acc. to Fig. 32 = 105 %. When the overexcitation is equal to $E_{maxcount}$, tripping is obtained after a time equal to the setting of t_1

When the overexcitation is equal to the set value of E_{max} , tripping is obtained after a time equal to the setting of t_6 . A suitable setting would be $E_{max}=140\%$ and $t_6=4$ s.

The interval between E_{\max} and E_{countmax} is automatically divided up in five equal steps, and the time delays t_2 to t_5 will be allocated to these values of overexcitation. In this example, each step will be $(140-105)/5=7\%$. The setting of time delays t_1 to t_6 are listed in the table below.

Table 9: Settings

U/f op (%)	Timer	Time set (s)
105	t1	7 200 (max)
112	t2	600
119	t3	60
126	t4	20
133	t5	8
140	t6	4

Information on the cooling time constant T_{cool} should be collected from the power transformer manufacturer.

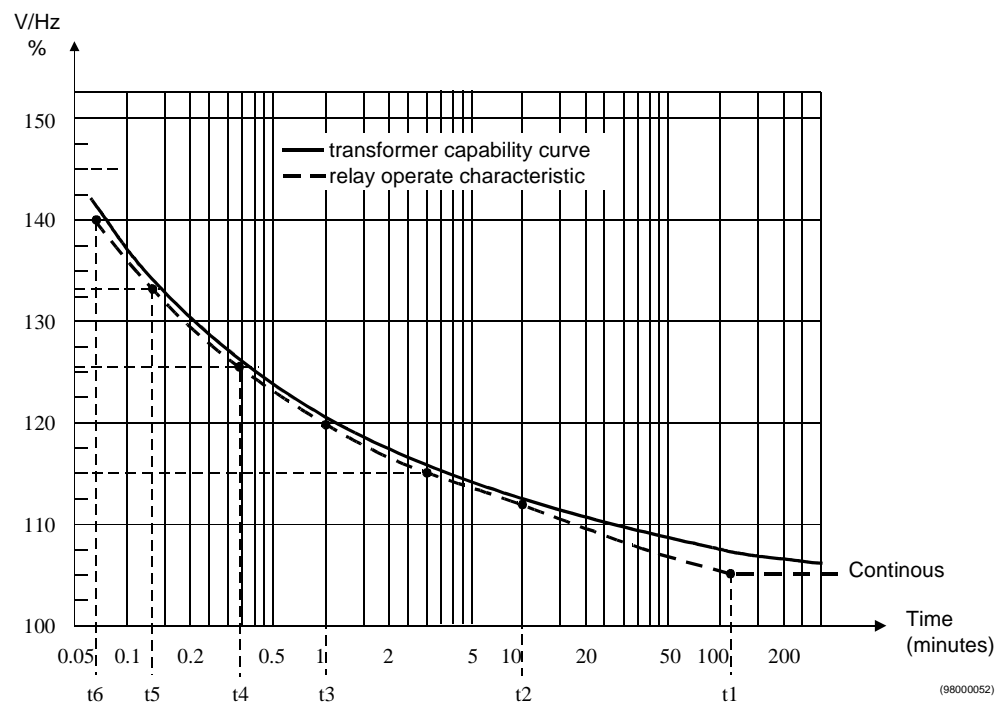


Fig. 32 Example on overexcitation capability curve and V/Hz protection settings for power transformer

Control functions

20 Voltage control for power transformers (VCTR)

20.1 General

When the load in a power network is increased the voltage will decrease and vice versa. To maintain the network voltage at a constant level power transformers are usually equipped with an on-load tap changer. An “on load tap changer” (OLTC) alters the power transformer ratio in a number of predefined steps and in that way changes the voltage. Each step usually represents a change in voltage of approximately 0.5-1.5%.

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. 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 than 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 an option for parallel control of up to four power transformers, based on the circulating current method, with terminal-to-terminal communication via LON bus.

The VCTR function block can be used in the logic scheme together with AND, OR, Timers, Command block, Event blocks etc.

20.1.1 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 remotely via binary signals connected to the **EXTMAN**, **EXTAUTO** inputs on VCTR function block when the operation mode is ExtMMI.

Commands**VoltageControl****Manual/Auto**

The current control mode is retained when the operation mode is changed.

20.2**Manual control**

In manual control mode it is possible to issue RAISE and LOWER commands to the tap changer locally from the built-in HMI or remotely via binary signals connected to corresponding inputs to the VCTR function block.

Commands**VoltageControl****RaiseVoltage/LowerVoltage**

It should be noted that VCTR function still supervises the manual commands in the following way:

- manual RAISE commands is blocked when busbar voltage exceeds U_{\max} value
- manual LOWER commands is blocked when the busbar voltage falls to a level between U_{block} and U_{\min}
- any manual command is blocked when the primary current exceeds the preset value
- one of the manual commands when the tap changer is in one of the extreme positions

It should be noted that VCTR function will not automatically regulate the power system voltage while manual control mode is selected.

20.2.1**Selection of control location**

Operation mode defines the location from which tap changer can be manually operated. When operation mode is selected it is as well important to select manual control mode to enable VCTR function to issue manual commands (see section 20.1.1).

It is possible to have the following human-machine-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)

It is possible to choose between Internal HMI and External HMI via one command from RET 521 built-in HMI. When InternalMMI is selected, only the built-in HMI can be used for manual RAISE and LOWER commands, i.e. VCTR rejects all “terminal remote” manual commands. On the other hand, when ExternalMMI is selected, the operation mode have to be chosen amongst three possible options.

Command

VoltageControl

IntMMI/ExtMMI

Normal control philosophy for External HMI is that the control location closer to the tap changer has the higher priority (i.e., local control panel has higher priority than station control etc.), but in RET 521 it is possible to choose between two different control philosophies.

First possibility is that the external operation mode can be selected to be “with priority”. This means that the signal LOCCMD has higher priority than STACMD, and STACMD has higher priority than the REMCMD signal (see figure 33). A demand on the VCTR function in “priority mode” is that for External MMI operation mode should be stored in a non-volatile memory in case of power failure. (Signals connected to REMCMD and STACMD inputs shall be a pulse). It should be noted that once the

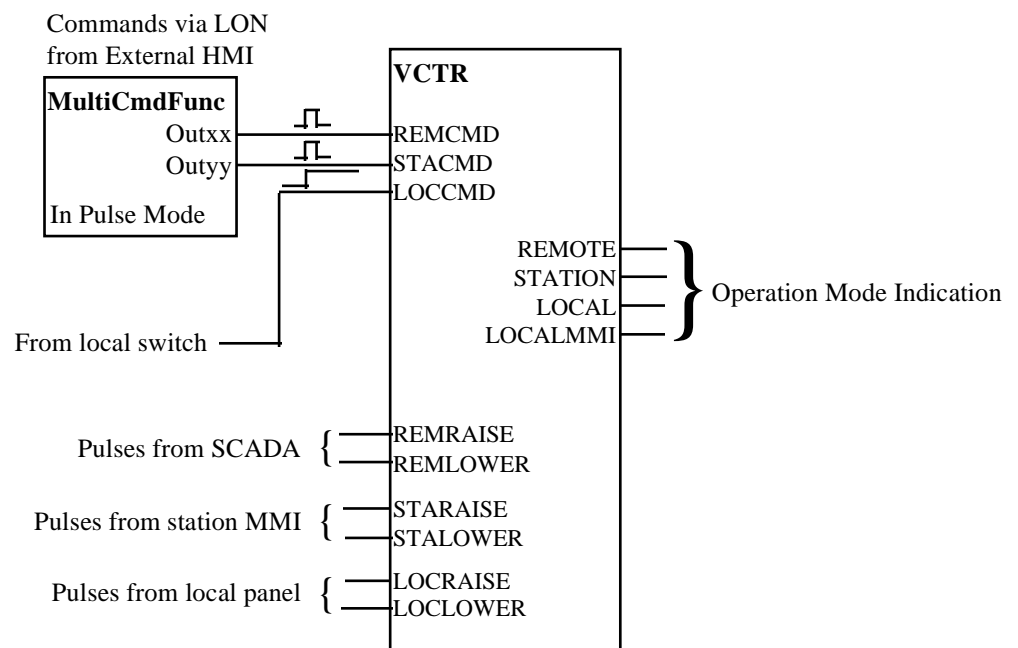


Fig. 33 External HMI Operation Mode selection “with priority”

LOCCMD signal is set back to zero, new pulse is required to STACMD or REMCMD input in order to set the VCTR control back to station or remote level.

Second possibility is that the external operation mode can be selected to be “without priority”. This means that one or more external HMI can be selected at the same time without any restrictions. In this case signals connected to REMCMD and STACMD inputs shall be steady signals (see figure 34). If all the inputs REMCMD, STACMD and LOCCMD set to zero the REMOTE operation mode is selected as default.

Selection between Priority or NoPriority is made by one of the settings for VCTR function. This settings can be changed via built-in HMI or SMS BASE.

For External HMI RAISE and LOWER commands are issued to the RET 521 as binary signals via binary input card or LON communication and command blocks (see figures 33 & 34).

Actual operation mode is indicated by the output binary signals **REMOTE**, **STATION**, **LOCAL** and **LOCALMMI** from VCTR function.

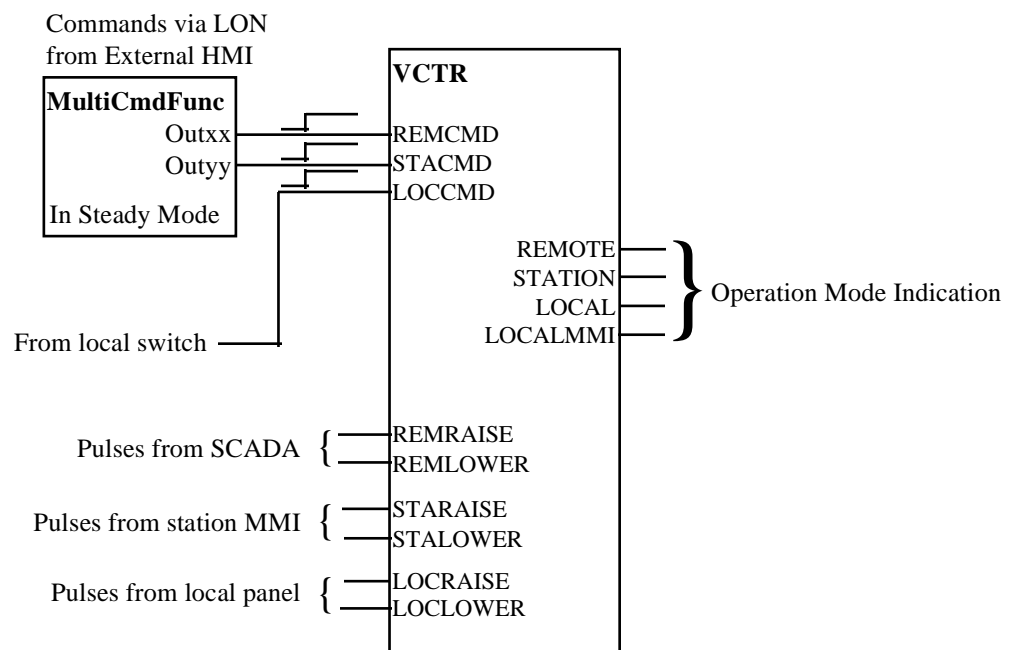


Fig. 34 External HMI Operation Mode selection “without priority”

20.3**Automatic control**

In automatic control mode the VCTR function will regulate the voltage according to the active settings and check if any of the blocking conditions are fulfilled. When ordering it must be specified if the terminal should be equipped with a single transformer automatic control function, or a parallel transformer automatic control function.

20.3.1**Automatic control for a single transformer**

The VCTR for single transformer assumes that the configuration consists of one single power transformer, thus any other transformers are not taken in account for automatic control.

20.3.1.1**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 (see section 20.3.1.4 for more details). It is possible to use two different sets of these analogue quantities. If all three phase-to-earth voltages and all three phase currents are available on the secondary side of the transformer, then VCTR will use internally calculated positive sequence quantities for all calculations. Alternatively if only one phase-to-phase voltage from the secondary side is available it will be used together with corresponding two phase currents for all calculations (see figure 35). It is not possible to use one phase-to-earth voltage for VCTR function.

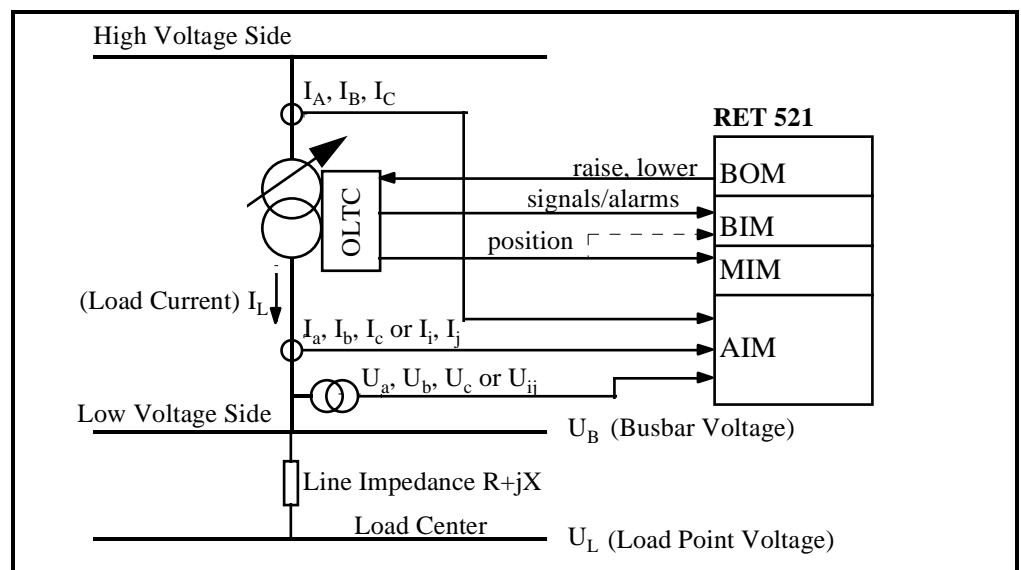


Fig. 35 Signal flow for a single transformer with voltage control

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 are shared with other functions in the terminal, such as the differential protection function.

In figure 35, the busbar voltage U_B is a shorter notation for the measured voltages 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.

20.3.1.2

Regulation principle

The VCTR measures the busbar voltage U_B . If no other additional features are enabled (i.e. load drop compensation, voltage adjustment etc.) this voltage is further used for voltage regulation.

The VCTR function then compare this voltage with the set voltage, U_{set} and decides which action should be taken. To avoid unnecessary switching around the setpoint, a deadband (i.e. degree of insensitivity) is introduced. The deadband is symmetrical around U_{set} (see figure 36). One half of the deadband will be denoted as ΔU from here on and this symbol will be used. The setting for ΔU , i.e. parameter with name “**Udead-band**” in SMSBASE under VCTR function, should be set to a value near to the power transformer’s tap changer voltage step (typically 75% of the tap changer step).

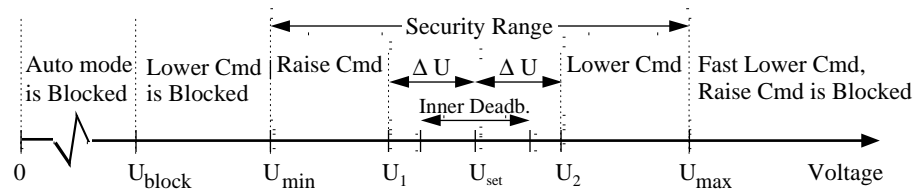


Fig. 36 Voltage Scale

During normal operating conditions the busbar voltage U_B , stays within the deadband (i.e. interval between U_1 and U_2 on figure 36). In that case no actions will be taken by VCTR. However, if U_B becomes smaller than U_1 or bigger than U_2 , an appropriate lower or raise timer will start. The timer will run as long as the measured voltage stays outside the inner deadband, which is fixed to 70% of $2 \cdot \Delta U$. If this condition persist longer than a preset time by the voltage/time characteristics (see section 20.3.1.3) the appropriate LOWER or RAISE command will be issued. If necessary, the procedure will be repeated until the busbar voltage is again within the inner deadband.

This way of working is used by VCTR while the busbar voltage is within security range $[U_{min}, U_{max}]$. A situation where U_B falls out of this range will be regarded as an abnormal situation and the following will happen:

When the busbar voltage falls below U_{\min} , but still above U_{block} , no further manual or automatic LOWER commands will be executed.

When the busbar voltage falls below the undervoltage limit U_{block} , automatic control will be blocked, but manual commands in both direction can be executed.

If the busbar voltage rises above U_{\max} , no further RAISE commands are allowed. In this case the VCTR function can execute one or more fast step down commands (i.e. LOWER commands) in order to bring the voltage back into the security range, $[U_{\min}, U_{\max}]$. The fast step down (FSD) function operation can be activated in one of the following three ways: off / auto / auto&manual, according to the setting of “**FSDMode**” parameter. The lower command, in fast step down mode, is always issued with shortest permissible time delay t_2 .

The measured busbar voltage U_B is shown on the HMI as a service value under menu

Service Report

Functions

VoltageControl

Measurands

BusbarVoltage

20.3.1.3

Time characteristic

Time characteristics defines the amount of time that should elapse between the moment when measured voltage exceeds the deadband interval until the appropriate RAISE or LOWER command is issued to the tap changer.

The main purpose of the time delay is to prevent unnecessary OLTC operations due to temporary voltage fluctuations. The time delay may also be used for OLTC co-ordination in radial distribution networks in order to decrease the number of unnecessary OLTC operations. This can be done by setting a longer time delay closer to the consumer and shorter time delays higher up in the system.

First time delay, t_1 , is used as a time delay (usually long delay) for the first command in one direction. It can have a constant or inverse time characteristic, according to the setting “**t1Use**” (=Const./Inverse). For inverse time characteristic bigger voltage deviation from U_{set} value will result in a shorter time delay, but the shortest delay will be equal to the “**tMin**” setting. This setting should be coordinated with the tap changer mechanism operation time. Constant time is independent of the voltage deviation.

The inverse time characteristic for the first time delay follows the formulas:

$DA = |U_B - U_{\text{set}}|$; DA is absolute voltage deviation from the set point

$D = \frac{DA}{\Delta U}$; D is relative voltage deviation in respect to set deadband value

$t_{1_delay} = \frac{t_1}{D}$, but condition $t_{1_delay} > t_{\min}$ have to be fulfilled as well

This practically means that t_{1_delay} will be equal to set t_1 value when absolute voltage deviation DA is equal to ΔU (i.e. relative voltage deviation D is equal to 1). For other values see figure 37. It should be noted that operating times shown on this figure are for 30, 60, 90, 120, 150 & 180 seconds settings for “**t1Use**” and 10seconds for “**tMin**”.

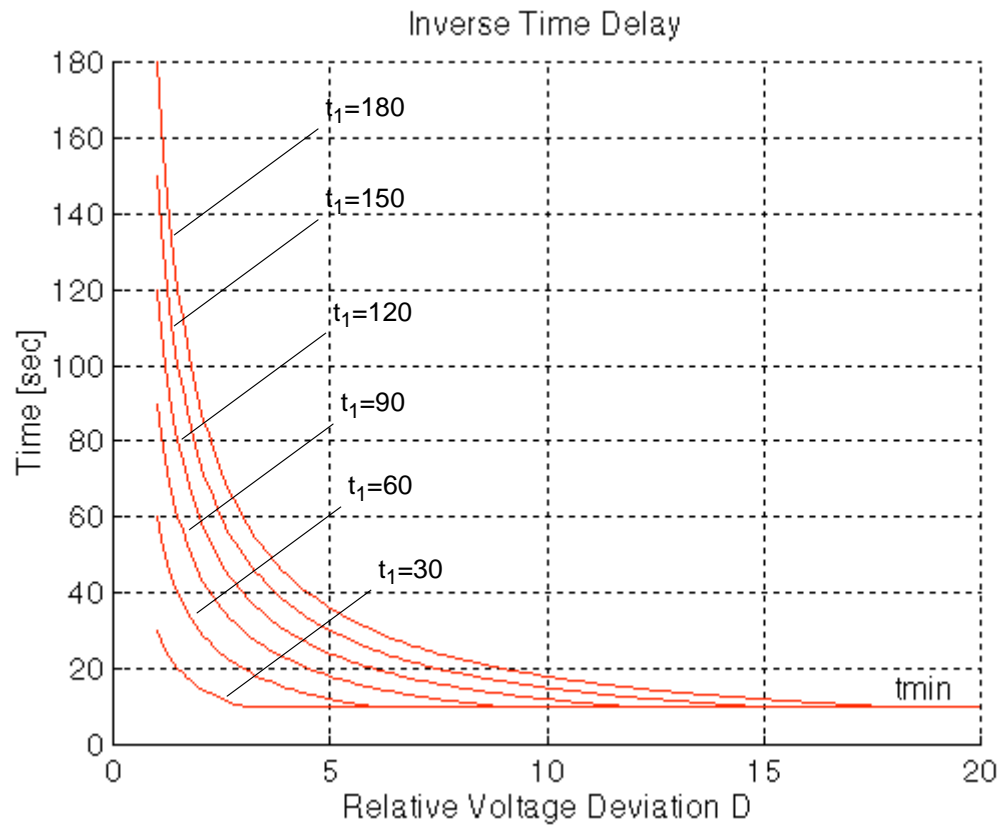


Fig. 37 Inverse time characteristic for VCTR

Second time delay, t_2 , will be used for consecutive commands (i.e. command in the same direction as the first command) and for the fast step down function when the bus-bar voltage exceeds U_{max} value. It can be constant or inverse according to the setting “**t2Use**” (=Const./Inverse). Inverse time characteristic for the second time delay follows the similar formulas as for the first time delay, but t_2 setting is used instead of t_1 .

20.3.1.4

Line voltage drop

The purpose with the line voltage drop compensation is to control the voltage not at the power transformer low voltage side, but at a point closer to the load point.

Figure 38 shows the vector diagram for a line modeled as a series impedance with the voltage U_B at the LV busbar and voltage U_L at the load center. The load current along the line is I_L , the line resistance and reactance from the station busbar to the load point are R_L and X_L . The angle between the load point voltage and the current, is ϕ_L . If all this parameters are known U_L can be obtained by simple vectorial calculations.

Values for R_L and X_L are given as settings in primary system ohms. If more than one line is connected to LV busbar an equivalent impedance should be calculated and given as a parameter setting.

The LDC feature can be turned Off/On by the setting parameter OperationLDC. When it is enabled, voltage U_L will be used by VCTR functions for voltage regulations instead of voltage U_B (see section 20.3.1.2). However, the VCTR function will still perform the following two checks:

- 1) Magnitude of measured busbar voltage U_B should be within the security range, $[U_{min}, U_{max}]$. If busbar voltage fall-out of this range the LDC calculations will be temporarily stopped until voltage U_B comes back within this range.
- 2) Magnitude of the calculated voltage U_L at the load point is limited to be lower than the magnitude of the measured busbar voltage U_B . In the algorithm of VCTR function magnitude of U_L can be only equal to or smaller than magnitude of U_B .

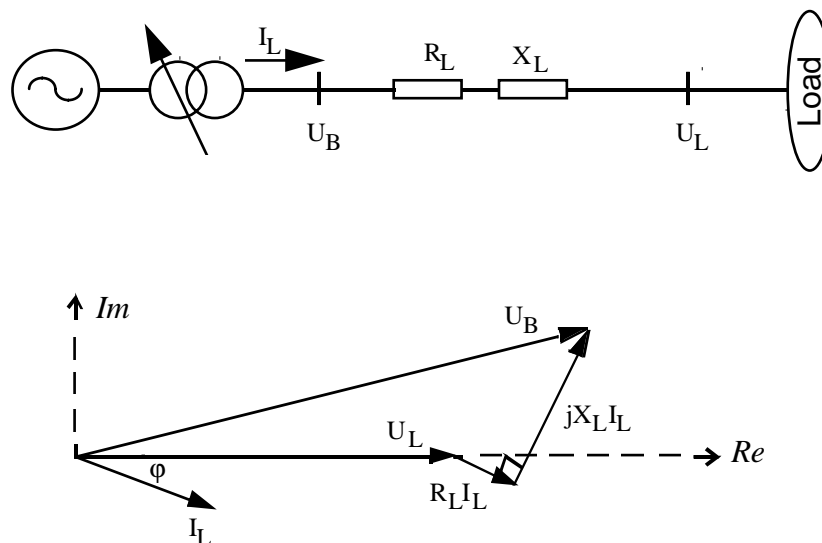


Fig. 38 Vector diagram for line voltage drop compensation

The calculated load voltage U_L is shown on the HMI as a service value under menu

Service Report

Functions

VoltageControl

Measurands

LoadVoltage

20.3.1.5

Load voltage adjustment

Due to the fact that most loads are proportional to the square of the voltage, it is possible to provide a way to shed part of the load by decreasing the supply voltage for a couple of percent.

It is possible to do this voltage adjustment in two different ways in RET 521:

- 1 Automatic load voltage reduction, proportional to the load current
- 2 Constant load voltage adjustment with four different preset values.

For the first principle the voltage reduction is dependent on the load and maximum voltage reduction should be obtained at rated load of the transformer.

The second principle is a constant voltage adjustment of the setpoint voltage (positive or negative) activated with a binary signal connected to the VCTR function block inputs LVA1, LVA2, LVA3 & LVA4. The corresponding voltage adjustments factors are given as settings parameters LVAConst1, LVAConst2, LVAConst3 & LVAConst4. The VCTR function will accept only one active input at a time, and that is the input which was activated first.

With these factors, VCTR function, in fact, just temporary adjusts the value of the set voltage U_{set} as per the following formula:

$$U_{set, adjust} = U_{set} + S_a \cdot i_L + S_{ci}$$

Where the symbols have the following meanings:

$U_{set, adjust}$	Adjusted set voltage in per unit
U_{set}	Original set voltage in per unit; Base quantity is U_{r2}
S_a	Automatic load voltage reduction factor, VRAuto
i_L	Load current in per unit; Base quantities are: For single 2-winding transformer: S_r and U_{r2} For single 3-winding transformer: S_{r2} and U_{r2} For "parallel" transformer: S_{base} and U_{r2}
S_{ci}	Constant load voltage adjust. factor for active input i

However it should be noted that the change factor should be negative in order to decrease the load voltage. After this calculation $U_{\text{set,adjust}}$ will be used by VCTR functions for voltage regulations instead of the original value U_{set} (see section 20.3.1.2).

The calculated set point voltage $U_{\text{set,adjust}}$ is shown on the HMI as a service value under menu

Service Report

Functions

VoltageControl

Measurands

ActualUset

20.3.2

Automatic control for parallel transformers

Parallel control of power transformers means control of two or more power transformers connected to the same busbar on the HV and LV sides. It is necessary that each transformer is controlled by a RET 521 terminal with VCTR function for parallel control.

20.3.2.1

Measured quantities

The same input quantities as for single control will be used for parallel voltage control. An additional requirement is a LON communication link between the terminals.

20.3.2.2

Regulation principle

This section will describe the parallel control when all RET 521 terminal in the group are in automatic control mode and parallel operation has been configured and selected by the user. Other situations will be discussed later.

Parallel voltage control, as implemented in RET 521, is based on 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 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 39 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:

$$|I_{cc_T1}| = |I_{cc_T2}| = \left| \frac{U_{T1} - U_{T2}}{Z_{T1} + Z_{T2}} \right|$$

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°, while T2 circulating current leads the busbar voltage for almost 90° (see figure 40 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.

The first and most important task for 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 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 plane is calculated in respect to it. This is simple and effective solution which eliminates any additional need for synchronization between terminals regarding VCTR function

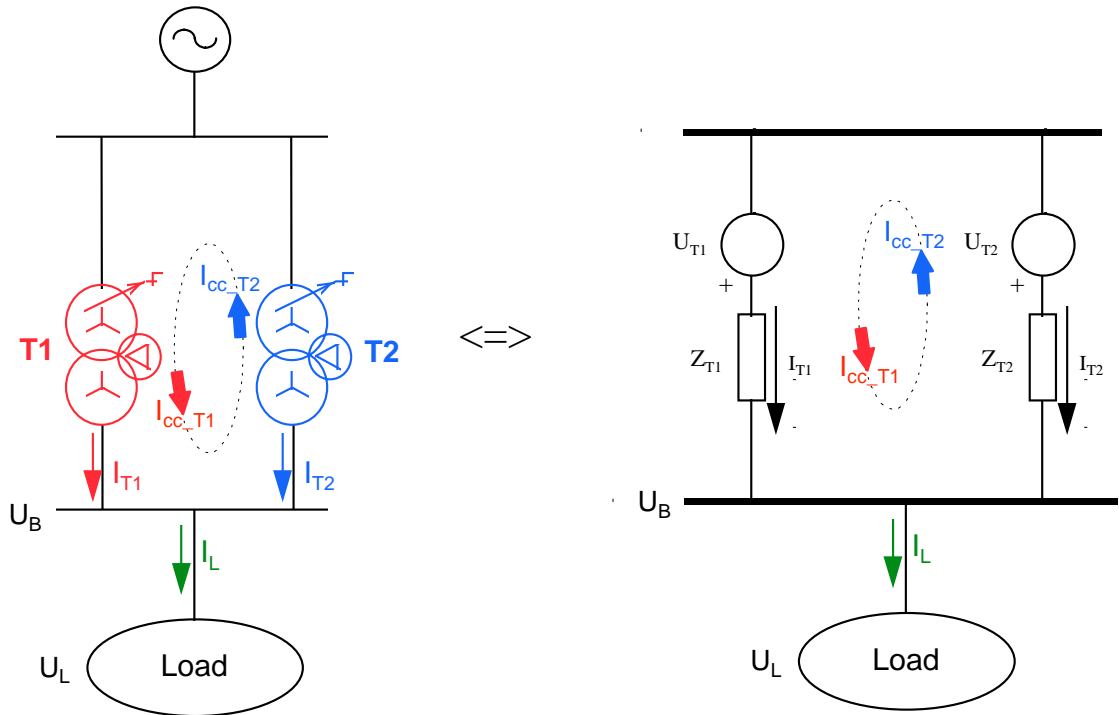


Fig. 39 Parallel group of two power transformers and its electrical model

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. Exchanged currents are expressed in per unit and must be referred to a common base power and base voltage. For this purpose the user should set the parameter “**Sbase**” to the same, common value in all terminals. The base power can be different from the transformer rated power if the group consists of transformers with different ratings. The transformer secondary voltage, U_{r2} , serves as the base voltage. From S_{base} and U_{r2} base current can be calculated as

$$I_{base2} = \frac{S_{base}}{\sqrt{3} \cdot U_{r2}}$$

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, which will be discussed later (see section 20.5).

The total load current in pu is defined as sum of all individual transformer currents:

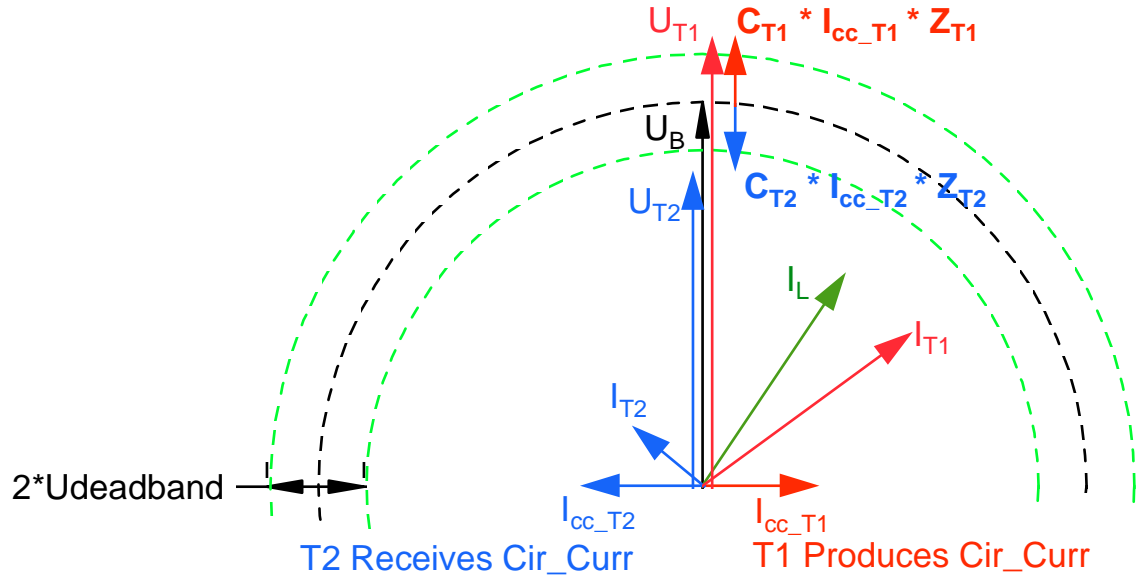
$$\bar{I}_L = \sum_{i=1}^k \bar{I}_i$$

where subscript i signifies the transformer bay number and k the number of parallel transformers in the group ($k_{\max}=4$). 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:

$$I_{cc_i} = -\text{Im}(\bar{I}_i - \bar{K}_{Li} \times \bar{I}_L)$$

where Im means the imaginary part of the expression in brackets and \bar{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 reactance is then converted to per unit value by VCTR function.

The minus sign is added in above equation in order to have positive value of the circulating current for the transformer which generates it.



$$\underline{I}_L = \underline{I}_{T1} + \underline{I}_{T2}$$

$$I_{cc_T1} = \text{Imag} \{ \underline{I}_{T1} - (Z_{T2} / (Z_{T1} + Z_{T2})) * \underline{I}_L \}$$

$$I_{cc_T2} = \text{Imag} \{ \underline{I}_{T2} - (Z_{T1} / (Z_{T1} + Z_{T2})) * \underline{I}_L \}$$

Fig. 40 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

CirCurrent

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:

$$U_{di} = C_i \cdot I_{cc_i} \cdot X_i$$

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:

$$U_i = U_B + U_{di}$$

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 20.3.1. 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 40.

20.3.3

Substation topology logic

The switchyard topology (connections between transformers) within a parallel group is crucial for the parallel control module. This information is used by the VCTR functions in order to incorporate those transformers that are in the parallel group in the calculations. When a transformer is disconnected, e.g. T3 in figure 41, and corresponding signal is connected to VCTR function of transformer T3, it will notify the two other parallel control modules (T1 and T2) in the group by sending a “DISC=1” message to the T1 and T2 terminals (see section 20.3.6 for more details).

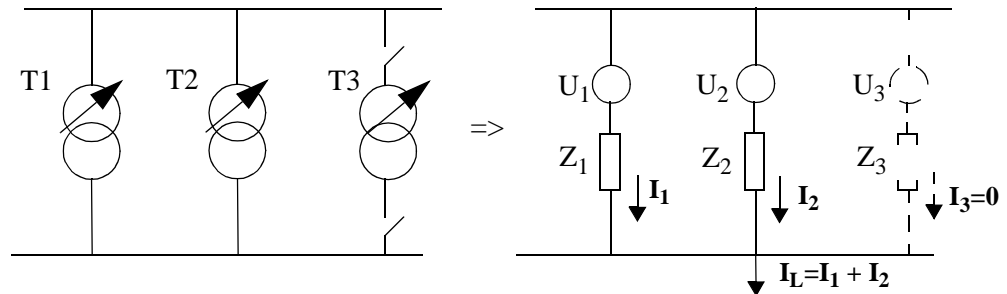


Fig. 41 Disconnection of one transformer in a parallel group.

However, this information might not be enough when the switchyard is complex (e.g. double busbar on one or both side of the transformer, bus section and bus coupler bays etc.). For these cases the user have to engineer station topology specific logic which will decide which transformers belong to the parallel group(s). For this purpose the VCTR function block is fitted with four binary inputs signals (**T1INCLD**,..., **T4INCLD**) which should be used to indicate which transformers are included in the parallel group. This information have to be passed to all group members. The user is free to connect any signal to these inputs.

In case of very complex substation, when the configuration logics available within RET 521 is not enough, one solution can be to use an external control terminal (i.e. REC 561) which produce/calculates necessary signals (**T1INCLD**,..., **T4INCLD** & **DISC**) for all RET 521 terminals working in the parallel group. All necessary information can be exchanged via LON bus between RET 521 terminals and REC 561 terminal.

The VCTR function block is also fitted with four outputs (**T1PG**,..., **T4PG**) for indication of the actual composition of the parallel group that itself is a part of. If parallel operation mode has been selected in the terminal with **TRFID**=Tx, the TxPG signal will always be set to 1.

The parallel module will consider communication messages only from the voltage control functions working in parallel (i.e. according to the current station configuration). When the parallel voltage control module detects that no other transformers work in parallel it will behave as single voltage control module in automatic mode.

20.3.4

Line voltage drop compensation for parallel control

The line voltage drop compensation for single transformer is described in section 20.3.1.4. The same principle is used for parallel control except that total load current, I_L , is used in calculation instead of individual transformer current. See Fig. 39 for details. Same values for “**Rline**” and “**Xline**” parameters should be given in all terminals. There is no automatic change of these parameters due to change in the substation topology, thus they should be changed manually if needed.

20.3.5

Communication between terminals

Communication between different parallel voltage control modules is managed by the station bus, LON. A special network variable, that is adapted for the parallel voltage control, is implemented in the RET terminal. The variable is updated in the receiver terminal, by cyclic sending of data from the source terminal under normal operation. However, when some important changes are detected by VCTR function in the source terminal the message will be sent immediately.

The configuration parameter “**TXINT**”, on the VCTR function block, specifies the period of time between two sendings of data. There is a corresponding parameter, “**RXINT**”, that specifies the maximum time between two updates of data from other terminals. If the updated message is not received within the time determined by parameter “**RXINT**” the communication error is set.

The communication configuration can be divided in two parts:

- Configuration of the voltage control parallel module
- Configuration of the LON Network

The parallel modules have to have unique identities in order to simplify the network configuration and the functional overview. This identity concerns **exclusively** the parallel voltage control. For RET 521 these identifiers are predefined as T1, T2, T3 & T4 (i.e. transformers 1 to 4). In figure 41 there are three RET terminals with the parameter “**TRFID**” set to T1, T2 and T3, respectively. The identity will follow the information if, e.g., the SEND-block in T1 is connected to T1Recv in terminal T2 and T3. Enabling receive blocks for each terminal in the parallel group is done with the parameters **T1RXOP**=Off/On,..., **T4RXOP**=Off/On. Settings in the three terminals, shown in figure 41, should be:

Table 10: Identification example for RET terminals (as supposed in Fig. 41)

TRFID=T1	T1RXOP=Off	T2RXOP=On	T3RXOP=On	T4RXOP=Off
TRFID=T2	T1RXOP=On	T2RXOP=Off	T3RXOP=On	T4RXOP=Off
TRFID=T3	T1RXOP=On	T2RXOP=On	T3RXOP=Off	T4RXOP=Off

It should be noted that is absolutely necessary to set this parameter to off for the “own” terminal.(i.e. for transformer with identity T1 parameter T1RXOP must be set to off etc.).

The LON network is configured by using the LNT 505 LON Configuration Tool where variable bindings between the terminals are specified and connected.

The parallel operation must be activated by setting parameter OperationPAR before VCTR function sends any data on the LON bus. Figure 42 shows the LON connections for the parallel group of three transformers from figure 41.

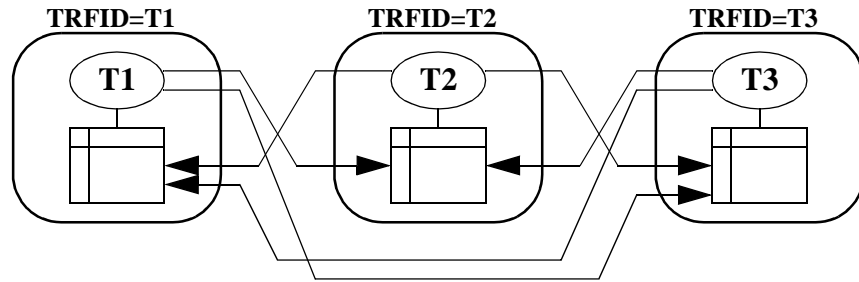


Fig. 42 LON network connections between terminals in the parallel group.

20.3.6

Exchanged information

The information exchanged between the modules can be expressed as a *data set*. All data in the data set will be updated at the same time broadcast which guarantees data consistency. Each data set has its own database object in the terminal database which accomplish the connection between the network and the code.

The status of **TxRXOP** (=Off/On) decides whether the data set should be supervised by the receive time interval parameter or not. The data set contains the following items, where Tx is the Terminal no. x:

Table 11: Exchanged data set

NAME	COMMENT
CMODE	= 1, Tx's control mode is automatic, = 0, Tx's control mode is manual.
MBLK	= 1, Tx's VCTR module is blocked, = 0, Tx's VCTR module is not blocked.
TXID	Terminal identification (T1,..., T4)
DISC	= 1, Tx is disconnected from busbar and should be excluded from the parallel group, = 0, Tx is connected to busbar and is a member of the parallel group.
RECURR	Tx's load current, real part, per unit value.
IMCURR	Tx's load current, imaginary part, per unit value.
MASTER	= 1, Tx is Master. (future use) = 0, Tx is Slave.
SLAVE	Select slave to receive message. (future use)
TCPOS	Tx's tap changer position. (future use)
RAISE	= 1, Tx issues a raise command, (future use) = 0, no command.
LOWER	= 1, Tx issues a lower command. (future use) = 0, no command.

Note: The data set cannot be modified by the user.

20.4

Manual control of a 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 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.

Rule 2: If U_{di} is negative and its module is greater than ΔU , then initiate a RAISE command.

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.

20.5

Blocking conditions

The purpose of blocking is to prevent the tap changer from operating under conditions that can damage the tap changer, or exceed other power system related limits.

For VCTR function three types of blocking are defined:

- *Total block*
- *Partial block*
- *Automatic block*

The following is an overview of all blocking conditions sorted under above defined blocking types. The actual blocking condition (i.e. None, Total, Automatic, Partial) is shown on the HMI as a service value under the menu

Service Report

Functions

VoltageControl

Measurands

BlockCond

20.5.1

Total block

Total block prevents any tap changer operation independent of the control mode. The following conditions will cause the total block.

Table 12: Total block conditions

Overcurrent (temporary blocking)	When any one of the three HV currents exceed pre-set value VCTR function will temporarily be totally blocked
Total block via settings (manual reset)	VCTR function can be totally blocked via setting parameter " TotalBlock ", which can be changed from HMI or SMS BASE
Total block via configuration (Manual deblocking)	Voltage control function can be totally blocked via any binary signal connected in the CAP 531 configuration tool to binary input ETOTBLK on the VCTR function block
Analog input error (Manual correction needed)	Binary output signal ERROR from VCTR function indicates a configuration error of the analog channels, that is, if the connection is missing according to the selected VCTR function block type. This error is considered as a fatal error and results in total block of the VCTR function. This error can be reset by downloading a correct configuration from the CAP 531 configuration tool.

20.5.2

Partial block

Partial block prevents operation of the tap changer only in one direction (i.e. only RAISE or LOWER command is blocked) in manual and automatic control mode. The following conditions will cause the partial block.

Table 13: Partial block conditions

Maximum voltage limit (Limitation in one direction)	<p>If the busbar voltage U_B (not the compensated load point voltage U_L) exceeds U_{max} (see figure 36), further RAISE commands will be blocked and, if allowed by settings, a fast step down action will be performed in order to re-enter the permitted range $U_{min} < U_B < U_{max}$.</p> <p>The Fast Step down function is blocked when the lowest voltage tap position is reached.</p>
Minimum voltage limit (Limitation in one direction)	<p>If the busbar voltage U_B (not the calculated load point voltage U_L) is between U_{block} and U_{min} level (see figure 36), further LOWER commands will be blocked independent of the control mode.</p>
Extreme tap changer positions (Limitation in one direction)	<p>This blocking function supervises the extreme positions of the tap changer according to the setting parameters "LowVoltTap" and "HighVoltTap". When the tap changer reaches one of these two positions further commands in the corresponding direction will be blocked.</p>

20.5.3

Automatic mode block

Automatic block prevents automatic voltage regulation, but the tap changer can be still controlled manually. The following conditions will cause the automatic block.

Table 14: Automatic mode block conditions

Automatic block via settings (Manual deblocking)	Automatic operation of VCTR function can be blocked via setting parameter " AutoBlock ", which can be changed from HMI or SMS BASE
Automatic block via configuration (Manual deblocking)	Automatic operation of voltage control function can be blocked via any binary signal connected in the configuration to binary input EAUTOBLK on the VCTR function block
Undervoltage (Temporary blocking)	<p>If the busbar voltage U_B falls below U_{block} the automatic voltage control is blocked. Operations in manual mode is not blocked under these circumstances because it usually corresponds to a disconnected power transformer. This allows the tap changer to be operated before reconnecting the power transformer.</p>

Table 14: Automatic mode block conditions (Continued)

Command error (Needs manual deblocking)	<p>Typical operating time of the tap changer mechanism is around 3-8 seconds. Therefore, the function should wait for a position change before a new command is issued. The command error signal, CMDERR, will be set if the tap changer position does not change one step in correct direction within the time given in the parameter "tTCTimeout". The tap changer module will then indicate the error until a successful command has been carried out. As well, this error condition can be reset by changing control mode of VCTR function to Manual and then back to Automatic.</p> <p>For additional information see "Monitoring of tap changer operation" on page 104.</p>
Position indication error (Needs manual deblocking)	<p>Two type of errors can occur:</p> <ul style="list-style-type: none"> • the input hardware module failure (BIM/IOM or MIM) • the input signal itself is corrupted <p>Supervision of the input hardware module is provided by connecting the corresponding error signal to the INERR input (input module error) on the VCTR function block.</p> <p>Supervision of the input signal for binary converter is provided by its output signal CNV-ERROR which takes care of both the parity check and binary input module error.</p> <p>Supervision of the input signal for MIM can be done in the standard way. For example, the measurement range can be supervised by setting the MIM parameters I_Max and I_Min to desired values, e.g., I_Max = 20mA and I_Min = 4mA. Signals will be generated if these values are exceeded.</p> <p>The VCTR automatic control will be blocked if position indication error is detected. This error condition can be reset by changing control mode of VCTR function to Manual and then back to Automatic.</p>
Disconnected transformer (Temporary deblocking)	<p>When the transformer has been disconnected from LV busbars, the tap changer automatic control can be blocked. The binary input signal DISC into VCTR function should be set to one to indicate that transformer is disconnected.</p> <p>Blocking will be removed when the transformer is reconnected (i.e. input signal set back to zero).</p>

Table 14: Automatic mode block conditions (Continued)

Reversed Action (Temporary blocking)	<p>The risk of voltage instability increases as transmission lines become more heavily loaded in an attempt to maximize the efficient use of existing generation and transmission facilities.</p> <p>In the same time lack of reactive power may move the operation point of the power network to the lower part of the P-V-curve (unstable part). Under these conditions, when the voltage starts to drop, it might happen that a RAISE command can give reversed result i.e. a lower busbar voltage.</p> <p>Tap changer operation under voltage instability conditions makes it more difficult for the power system to recover. It might be therefore desirable to block the VCTR function temporarily.</p> <p>Requirements for this blocking are:</p> <ul style="list-style-type: none"> • The load current must exceed 95% of I_{rated}. • After a RAISE command, measured busbar voltage has lower value than its previous value • The second requirement has to be fulfilled for two consecutive RAISE commands <p>If all three requirements are fulfilled, VCTR automatic control will be blocked for a period of time given by the setting parameter "tREVACT" and the output signal REVACBLK will be set.</p> <p>The reversed action feature can be turned off/on with the setting parameter "OperationRA".</p>
--	--

20.5.4

Automatic blocking in parallel mode

Automatic block prevents automatic voltage regulation, but the tap changer can be still controlled manually. There are two additional automatic blocking condition for parallel voltage control:

Table 15: Parallel blocking conditions

Communication error (Automatic deblocking)	<p>If the LON communication from any one of the terminal in the group fails it will cause the automatic block in all VCTR functions which belong to that parallel group (see section 20.5 for more details). This error condition will be reset automatically when the communication is re-established.</p>
---	---

Table 15: Parallel blocking conditions

Circulating current (automatic deblocking)	When the magnitude of the circulating current exceed the preset value it will cause the auto block condition of the VCTR function. User can set this feature on/off via setting parameter "operationCC" from HMI or SMS. This error condition will be reset automatically when the circulating current decrease below the pre-set value. This usually can be achieved by manual control of the tap changers.
--	--

20.5.5**Mutual blocking**

When one voltage control module blocks its operation all other voltage control modules working in parallel, with that module, should block their operation as well. To achieve this the affected VCTR function broadcasts a mutual block to other group members via LON communication. When mutual block is received from any of the group members, automatic VCTR operation is blocked in the receiving terminal, i.e. all units of the parallell group.

The following conditions in any one of the terminal in the group will cause mutual blocking:

- Over-Current
- Total block via settings
- Total block via configuration
- Analog input error
- Automatic block via settings
- Automatic block via configuration
- Under-Voltage
- Command error
- Position indication error
- Reversed Action
- Circulating current
- Communication error

It should be noted that partial blocking condition in any one of the terminal will not cause the mutual blocking (see section 20.5.2 for more details).

The terminal which is the "source" of the mutual blocking will set its AUTOBLK output as well as the output which corresponds to the actual blocking condition (i.e. IBLK for over-current). The other terminals which receive mutual block will only set its AUTOBLK output.

The mutual blocking persists until the terminal that dispatched the block signals cancels it. Another way to release the mutual blocking is to force the terminal which caused mutual blocking to *Single mode* operation. This is done by setting the binary input SNGLMODE on the VCTR function to high or setting the parameter “OperationPAR” to off from the built-in HMI or SMS.

The VCTR function can be forced to single mode at any time. It will then behave exactly the same way as described in section 20.3.1, except that LON communication messages are still sent and received, but the received messages are ignored. The terminal is at the same time also automatically excluded from the parallel group.

20.6 Tap changer monitoring

VCTR function has built-in extensive supervisory and monitoring features which are explained further in more details.

20.6.1 Tap changer position detection

Actual tap changer position can be measured via binary signals (BI) or by an analog signal (AI). The configuration parameter “**POSTYPE**” on VCTR function block should be correspondingly set to “None”, “BI” or “AI”. When the tap changer position indication is not available the POSTYPE parameter should be set to “None”.

Measured tap changer position is shown on the HMI as a service value under menu

Service Report

Functions

VoltageControl

Measurands

TapPosition

20.6.2 Tap changer extreme positions

This feature supervises the extreme positions of the tap changer according to the settings “**LowVoltTap**” and “**HighVoltTap**”. When the tap changer reaches its highest/lowest position, corresponding RAISE/ LOWER command is prevented in both automatic and manual mode.

20.6.3 Monitoring of tap changer operation

Output signal **RAISE** or **LOWER** are set high when VCTR function has decided that it is necessary to operate the tap changer. These outputs should be connected to a binary output module, BOM in order to give the command to the tap changer mechanism. The length of the output pulse can be set via the setting parameter “**tPulse-Dur**”.

Usually the tap changer mechanism can give a signal, “Tap change in progress”, when they are busy. This signal from the tap changer mechanism can be connected via BIM card to the VCTR input **TCINPROG**. This signal is used by VCTR function in three ways.

The use is to set the VCTR signal **TCOPER** to high in order to indicate tap changer operation and that the tap changer is blocked for further commands under this period of time. If **TCINPROG** input signal is not used or does not exist the **TCOPER** signal will be set every time when command is issued during time equal to **tTCTimeout** settings.

The second use is to detect jammed tap changer. A delay-on-pick-up timer is activated (set time equal to “**tTCTimeout**” settings) while the **TCINPROG** signal is active. If this timer times out before the **TCINPROG** signal is set back to zero the output signal **TCERR** is set high and VCTR function is blocked.

The third use is to check the proper operation of the tap changer mechanism. As soon as input signal **TCINPROG** is set back to zero the VCTR function expects to read new and correct value for the tap position. If this do not happen the output signal **CMDERR** is set high and VCTR function is blocked.

This feature can sometimes cause some practical problems at site during commissioning which can be solved by introducing delay on drop-off timer in the configuration (set from 1 to 3 seconds) between binary input for the tap changer in progress signal and the VCTR input **TCINPROG**. This time should be considered when setting **tTCTimeout**. It is also important to time the reading of the mA inputs so that a newly measured tap position reaches VCTR within the period of which **TCINPROG** is set. This can be obtained by setting a 2 s interval (approx) periodic reading of the mA input and/or enable deadband supervision.

Both MIM input 1 (MI11-) and the CNV (primary counter) function blocks are fitted with a delay parameter input. The value applied (e.g. 1 s) will also add up to the total delay that must be converted by the **TCINPROG** signal. The delay parameter input of the MIM and CNV function blocks is meant to prohibit fluctuations of the tap position to be transferred into the VCTR function.

This additional logical timer in the configuration will as well enable VCTR function to detect run-away of the tap changer mechanism.

20.6.4

Hunting detection

Hunting detection is provided in order to alarm when the voltage control gives an abnormal number of commands within a pre-defined period of time. Hunting can be the result of a narrow deadband setting or some other abnormalities in the control system.

The VCTR function will activate the output signal **HUNTING** when the number of tap changer operations exceed the number given by the setting “**DayHuntDetect**” during 24 hours or by the setting “**HourHuntDetect**” during one hour. Hunting detection is only active in automatic control mode.

20.6.5

Wearing of the tap changer contacts

Two counters, “**ContactLife**” and “**NoOfOperations**” are available within VCTR function. They can be used as a guide for maintenance of the tap changer mechanism.

The “ContactLife” counter represents the remaining number of operations (decremental counter) at rated load

$$\text{ContactLife}_{n+1} = \text{ContactLife}_n - \left(\frac{I_{load}}{I_{rated}} \right)^\alpha$$

where n is the number of operations and α is an adjustable setting parameter, “CLFactor”, with default value is set to 2. With this default setting an operation at rated load (current measured on primary side) decrements the ContactLife counter for one.

The “NoOfOperations” counter simply counts the total number of operations (incremental counter).

Both counters are stored in a non-volatile memory as well as the times and dates of their last reset. These dates are stored automatically when the command to reset the counter is issued. It is therefore necessary to check that terminal internal time is correct before these counters are reset. The counter value can be reset from the HMI menu branch:

Commands

VoltageControl

CLReset

or...

OCReset

. Both counters and their last reset dates are shown on the HMI as a service values under menu

Service Report

Functions

VoltageControl

Measurands

NoOfOperations/OCResetDate

or...

ContactLife/CLResetDate

21 Event function (EV)

21.1 General

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 REx 5xx terminal, data can be sent to other terminals over the LON bus.

21.2 Functionality

The events that are sent from the terminal can come from both internal logical signals and binary input channels. The internal signals are time-tagged in the main processing module, while the binary input channels are time-tagged directly on each I/O module. The events are produced according to the set-event masks. The event masks are treated commonly for both the LON and SPA channels. All events according to the event mask are stored in a buffer, which contains up to 1000 events. If new events appear before the oldest event in the buffer is read, the oldest event is overwritten and an overflow alarm appears.

The outputs from the Event function block are formed by the reading of status and events by the station HMI on either every single input or double input. The user-defined name for each input is intended to be used by the station HMI.

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.

Two special signals for event registration purposes are available in the terminal, Terminal restarted and Event buffer overflow.

21.3 Single and double indications

The inputs can be used as individual events or can be defined as double indication events.




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.

21.4**Communication between terminals**

The Event function block can also be 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.

21.5**Setting**

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 

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.

The event reporting can be set from the SMS as:

- Use event masks
- Report no events
- Report all events

Use of event masks is the normal reporting of events, that is, the events are reported as defined in the database.

An event mask can be set individually for each available signal in the terminal. The setting of the event mask can only be performed from the SMS.

All event mask settings are treated commonly for all communication channels of the terminal.

Report no events means blocking of all events in the terminal.

Report all events means that all events, that are set to OnSet/OnReset/OnChange are reported as OnChange, that is, both at set and reset of the signal. For double indications when the suppression time is set, the event ignores the timer and is reported directly. Masked events are still masked.

Parameters to be set for the Event function block are:

- NAMEyy including the name for each input.
- T_SUPRyy including the suppression time for double indications.
- INTERVAL used for the cyclic sending of data.
- BOUND telling that the block has connections to other terminals over the LON bus.

These parameters are set from the CAP 531 configuration tool. When the BOUND parameter is set, the settings of the event masks have no meaning.

22 Disturbance Report (DRP)

22.1 General

The aim of the Disturbance Report is to contribute to the highest possible quality of electrical supply. This is done by continuous collection of system data and, upon occurrence of fault, sorting and presenting a certain amount of pre-fault, fault and post-fault data.

The stored data can be used for analysis and decision making to find and eliminate possible system and equipment weaknesses.

22.2 Functionality

The Disturbance Report is a common name for several facilities to supply the operator with more information about the disturbances and the system. Some of the facilities are basic and some are optional.

The facilities included in the Disturbance Report are:

- Disturbance overview
- Indications
- Event recorder
- Trip values
- Disturbance recorder

The whole Disturbance Report can contain information for up to 10 disturbances each with the data coming from the parts mentioned above, depending on the options installed. All information in the Disturbance Report is stored in non-volatile flash memory. This implies, that no information is lost in case of loss of the power supply. The memory employs the FIFO principle, i.e. when the memory is full, the oldest disturbance will be overwritten.

On the built-in HMI the indications and the trip values are available. For a complete disturbance report SMS is required.

22.2.1

General disturbance information

22.2.1.1

Disturbance overview

is a summary of all the stored disturbances. The overview is only available via the Station Monitoring System (SMS). It contains:

- Disturbance index
- Date and time
- Trig signal (one, that activated the recording)

22.2.1.2

Disturbance data

Disturbance data can be accessed via the built-in HMI or via SMS. The date and time of the disturbance, the trig signal, the indications and the trip values are available provided, that the corresponding functions are installed.

22.2.2

Indications

Indications is a list of signals that were activated during the fault time of the disturbance.

22.2.3

Event recorder

The event recorder contains a list of up to 150 time tagged events, i.e. change of status of binary signals, for each disturbance.

22.2.4

Trip values

This function presents the phasors of selected currents and voltages before and during a disturbance.

22.2.5

Disturbance recorder

The disturbance recorder records analogue and binary signal data during the whole disturbance.

22.3 Settings

22.3.1 Signals

22.3.1.1 Binary signals

The Disturbance Report can be programmed to accept up to 48 binary signals. The Event Recorder and the Indication functions will use these binary signals for its function. In case the Disturbance Recording function is installed, the signals will be recorded as binary signals in this function.

22.3.1.2 Analogue signals

When the Disturbance Recorder is installed, up to 10 analogue signals can be selected for recording.

22.3.2 Triggers

The Disturbance Report function must be activated by a trigger in case of a disturbance. The trig conditions affect the entire disturbance report. As soon as a trig condition is fulfilled, a complete disturbance report is recorded. On the other hand, if no trig condition is fulfilled, there is no disturbance report. This implies the importance of choosing the right signals as trig conditions.

The following types of triggers are available:

- Manual trig
- Binary signal trig
- Analogue signal trig (over/under function)

22.3.2.1 Manual trig

Manual trig can be made either from the built-in HMI or via SMS. The possibility has been included to facilitate easy and convenient test of the Disturbance Report function.

22.3.2.2 Binary signal trig

Any of the 48 signals can be selected as a trigger for the Disturbance Report function. Thus, it is necessary to consider which signals should be included in the set of 48 signals and out of these, which should be used as a trigger. Incorrect choice may result in failure in initiating a recording in case of disturbance or unnecessary recording.

22.3.2.3 Analogue signal trig

Any analogue signal can be programmed to act as a trigger. The analogue signals are provided with level detectors both for under and over function. Selection of these signals and the operating level should be done with great care to avoid undue recordings. Specially under-current and under-voltage detectors should be used with great care.

22.3.3 Recording times

The recording time is valid for whole Disturbance Report, except for Indications. Indications are only recorded during the fault time.

The total recording time comprises the following parts:

- tPre, this is the so called pre-fault time. In fact it also includes a part of the fault condition due to the operating time of the trigger. The setting should be done so that this fact is taken into consideration. Thus the setting should cover the operating time for the slowest trigger and a few cycles of the true pre-fault condition.
- tFault is the fault duration time. In fact it includes a small part of the post fault condition, due to the reset time of the triggers. This time can not be set.
- tPost is the so called post-fault time. This time is settable and starts when all triggers have reset. The time should be set so that sufficient amount of post-fault data is recorded.
- tLim is the limit time. This setting will limit the recording time after the triggering. This parameter has been introduced to eliminate the risk of unwanted overwriting of valuable data. Since the recording memory employs the FIFO principle, this would be the case for the Disturbance Recording function, should a trigger not reset for one reason or another. The setting should be done considering the expected fault duration and set post-fault time.

23

Remote communication (RC)

23.1

General

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 computerised 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.

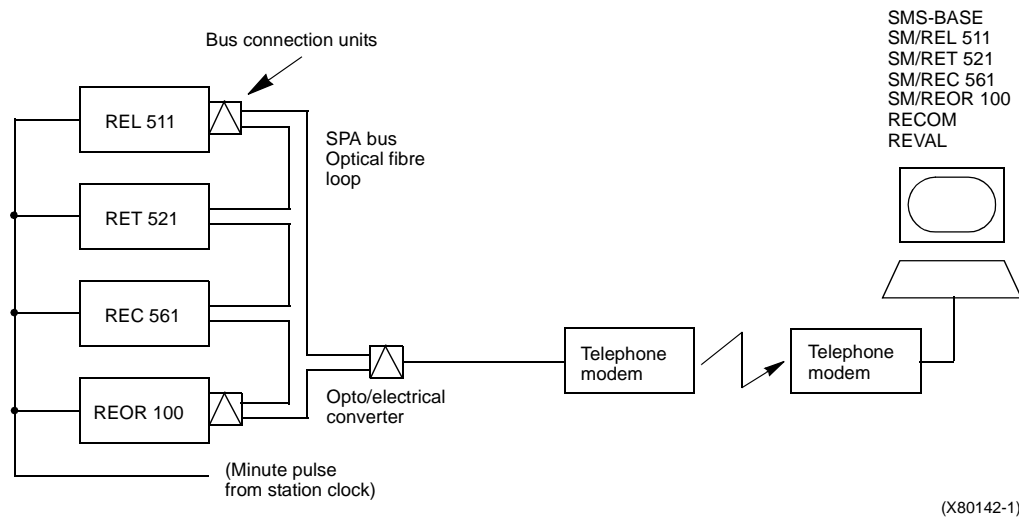


Fig. 43 Example of SPA communication structure for SMS

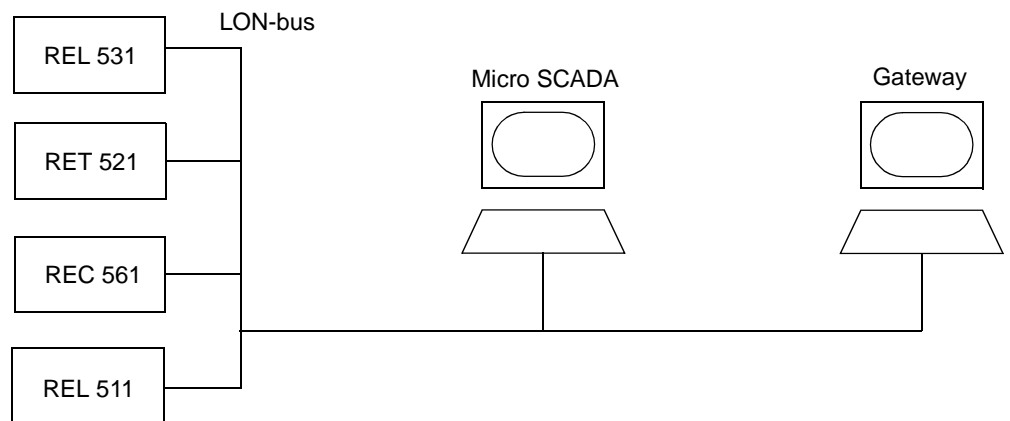


Fig. 44 Example of LON communication structure for SCS

23.2

Functionality

All remote communication to and from the terminal (including the front PC port communication) uses either the SPA-bus V 2.4 protocol or the LonTalk protocol.

The remote communication use 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.

23.2.1

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 a 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 SMS-BASE. Apart from this program the terminal specific program SM/RET521 is needed.

23.2.2

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.

23.3

Settings

The following settings are provided for the SPA communication:

On the front port:

- slave number
- baud rate

On the rear port:

- slave number
- baud rate
- active group restriction
- setting restriction

The parameters for the LON communication are set with a special tool called LNT, LON Network Tool.

Enhancing functionality

24

Tap position measuring

The actual tap changer position can be measured via binary input signals or via milli-amp input signal. Differential Protection function (DIFP) and Voltage Control function (VCTR) can use this measured tap changer position value to enhance their functionality.

24.1

Tap changer position measuring via mA card

Only the first input on mA card (i.e. MIM) is adapted for measuring, converting and presentation of the tap changer position. This MIM input will act as a tap position reading input when the parameter input OLTCOP of the MIM function block is set to On. When parameter input OLTCOP is set to Off the normal MIM functionality will be active and the tap position value is undefined (i.e. equal to 0).

The measurement of the tap changer position via MIM card is based on the principle that the specified mA input signal range (usually 4-20 mA) is divided into N intervals corresponding to the number of positions available on the tap changer. All mA values within one interval are associated with one tap changer position value. See figure 45 for more details.

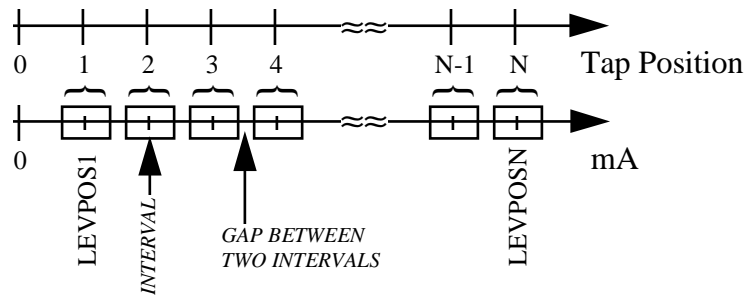


Fig. 45 Principle of tap position measuring via mA input signal

The number of available tap changer positions N is defined by setting the parameter input NOOFPOS of the MIM function block. Setting range for this parameter is between 1 and 39.

The mid point of the mA interval which correspond to tap position 1 is defined by setting the parameter input LEVPOS1 of the MIM function block. Setting range for this parameter is from 0.0 to 4.0 mA.

The mid point of the mA interval which correspond to tap position $N=NOOFPOS$ is defined by setting the parameter input LEVPOSN of the MIM function block. Setting range for this parameter is from 10.0 to 20.0mA.

Difference (i.e. the step) between two mid points of the two neighboring intervals is calculated as per the following formula:

$$\text{Step} = \frac{\text{LEVPOSN} - \text{LEVPOS1}}{N - 1} \quad [\text{mA}]$$

To insure secure reading of tap position, the size of the interval is smaller than the step between two interval midpoints. Interval size is calculated as per the following formula:

$$\text{INTERVAL SIZE} = 0.9 \cdot \text{STEP} \quad [\text{mA}]$$

Because the interval is symmetrical around its midpoint it is more important to calculate one half of its value as per the following formula:

$$\text{HALF OF INTERVAL SIZE} = \frac{\text{INTERVAL SIZE}}{2} \quad [\text{mA}]$$

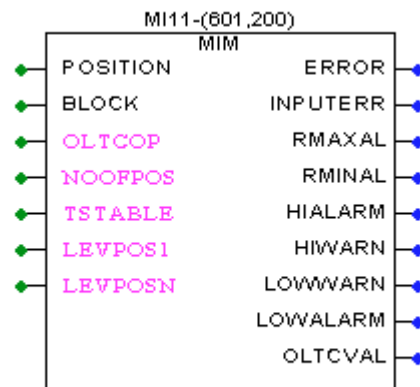


Fig. 46 The MIM/Input 1 function block representation in the CAP 531 configuration tool

If the mA input signal value is somewhere in between two intervals, i.e. in the gap, the tap position is undefined (i.e. equal to 0).

The output OLTCVAL shall be connected to the VCTR and DIFP function blocks as a tap changer position input. Output INPUTERR can be connected to the DIFP and VCTR function blocks to indicate faulty reading of tap position.

When MIM input No 1 is used for tap position measuring than the following two values are available as service report:

Measured mA input signal is shown on the HMI as a service value under menu

Service Report

MIM1

Measured tap changer position is shown on the HMI as a service value under menu

Service Report

MIM1

Practical Example:

For an tap changer with 17 steps and with mA input signal range of 4-20 mA the following can be calculated:

$$\text{STEP} = \frac{20 - 4}{17 - 1} = 1.0 \text{ mA}$$

$$\text{INTERVAL SIZE} = 0.9 \cdot 1.0 = 0.9 \text{ mA}$$

$$\text{HALF OF INTERVAL SIZE} = \frac{0.9}{2} = 0.45 \text{ mA}$$

From above data the following table can be produced for conversion of mA values to corresponding tap position numbers:

Table 16: mA interval vs. tap position

mA Interval	4.0±0.45	5.0±0.45	6.0±0.45	7.0±0.45	...	19.0±0.45	20.0±0.45
Tap Position	1	2	3	4	...	16	17

The tap position value will be 0 to indicate an undefined value, i.e., when the signal is found between two intervals or when the signal is out of specified input range, e.g. >0.0 mA.

To avoid any possibility that a fluctuating mA input signal can cause problem to the VCTR or DIFP functions, a settable time delay will be used before the tap changer value is reported. The parameter input TSTABLE of the MIM function block is used for this purpose. Setting range for this parameter is from 0 to 10 seconds.

24.2

Necessary MIM settings

To enable MIM card to report measured values to the main processing card it is important to set the parameter Operation to On and the parameter RepInt to a nonzero value (for example 1 second).

Note: Settings in SMS are not used to convert mA input signal into tap position value. Therefore it is important to set a scaling factor in SMS as shown below in order not to interfere with tap position reading:

MaxValue = 20; I_Max = 20; MinValue = 0; I_Min = 0;

If these four parameters are set as shown above they will insure that the scaling factor is one and that tap position will be measured according to the settings in the configuration.

24.3

Converting binary data

The binary converter function block (CNV) decodes binary data from up to six binary inputs to an integer value. The input pattern may be decoded either as binary format or BCD format depending on the setting of the parameter Codetype of the CNV function block. If this parameter is set to zero then binary decoding will be used or if it is set to one then BCD decoding will be used. See the description of CNV block in the RET 521 technical description manual for details on BCD and binary conversion.

To avoid any possibility that a bouncing binary input signal can cause problem to the VCTR or DIFP functions a settable time delay will be used before the tap changer value is reported. The parameter Tstable of the CNV function block is used for this purpose. Setting range for this parameter is from 0 to 10 seconds.

It is also possible to use even parity check of the input binary signal. The parity is checked if the parameter Paruse of the CNV function block in the configuration is set to On.

The input BIERR of the CNV function block can be used as supervisory input for indication of any external error in the system for reading of tap changer position.

Error check is implemented in the CNV function block. If an error is detected in the binary input signal, the ERROR output is set to one and the output VALUE is forced to zero.

The output VALUE shall be connected to the VCTR and DIFP function blocks as a tap changer position input. The ERROR output can be connected to DIFP and VCTR functions to indicate faulty reading of tap position.

24.4

Tap position reading for voltage control

The actual tap changer position can be measured via binary input signals or via milli-amp input signal. To give the information about tap position to the VCTR function the following needs to be done:

Outputs from the CNV or MI11 function blocks which holds actual tap position shall be connected to the input TCPOS of the VCTR function block. The ERROR output is connected to the corresponding input INERR of the VCTR function block to indicate an error in reading of tap position.

The parameter Postype of the VCTR function block can be set to None, BI (binary input) or AI (analog mA input). The input TCPOS has to be connected to the MI11 function block when AI is selected, or to the CNV function block when BI is selected. When the tap changer position indication is unavailable the Postype parameter should be set to None. This means that no supervision of the tap changer position and its operation is performed.

The lower and upper tap position settings in SMS BASE under VCTR function Low-VoltTap and HighVoltTap should be interpreted as following:

The Lowvolttap means the tap position (e.g. usually position 1) with maximum number of turns in the primary winding, that gives minimum busbar voltage on secondary side of the power transformer.

The HighVoltTap means the tap position (e.g. usually position N) with minimum number of turns in the primary winding, that gives maximum busbar voltage on secondary side of the power transformer.

24.5

Tap position reading for differential protection

The actual tap changer position can be measured via binary input signals or via mA input signal.

Under the menu Edit/Function Selector in the CAP 531 configuration tool, the function selector for the DIFP function block can be set to NoOLTC or OLTC. When the tap changer position indication is not available, the function selector shall be set to NoOLTC. In this way inputs and parameters related to reading of tap changer position, will not be visible on the function block.

When the tap changer position indication is available, The DIFP function selector shall be set to OLTC. Then to give the necessary information about tap position to the DIFP function the following need to be done:

Outputs from the CNV or MI11 function blocks which holds actual tap position shall be connected to the input TCPOS of the DIFP function block. The ERROR output is connected to the corresponding input OLTErr of the DIFP function block to indicate an error in reading of tap position.

The parameter Postype of the DIFP function block, can be set to BI or AI. The input TCPOS must be connected to the MI11 function block when AI is selected and to the CNV function block when BI is selected.

The parameter Oltc2w (two winding protection), or Oltc3w (three winding protection), of the DIFP function block, shall be set in accordance with physical location of the tap changer mechanism (i.e. tap changer mechanism located on primary, secondary or tertiary side). This setting is used to indicate to the differential function which winding will change number of turns when the tap changer position is changed.

The following settings in SMS-BASE for DIFP function are relevant for reading of tap changer position:

The setting NoOfTaps means the total number of tap positions.

The setting RatedTap means the tap number which corresponds to rated voltages set under settings for transformer data. In the same time these voltages will be used to calculate nominal turns ratio. This nominal turns ratio will be used when for any reason tap position reading is not available (i.e. tap value is 0 or tap position reading error is set to 1).

The setting MinTapVoltage means the tap 1 voltage, from the transformer name plate, of the winding with tap changer mechanism.

The settings MaxTapVoltage means the tap N (i.e. for maximum tap position) voltage, from the transformer name plate, of the winding with tap changer mechanism.

It should be noted that all above data can be easily found on the transformer name plate.

24.6

Practical example

For a two winding transformer with the following basic data

Rated Voltages:	132/11kV
Rated Power:	40MVA
Rated Currents:	175/2100A
Rated Impedance:	X=10,6%
Vector Group:	Yd11

and the following data about tap changer mechanism:

TAP	HV [kV]	LV [kV]
1	138,6	
2	136,96	
3	135,33	
4	133,71	
5	132,07	11
6	130,45	
7	128,79	
8	127,17	
9	125,4	
10	123,78	
11	122,14	
12	120,5	
13	118,88	
14	117,25	
15	115,61	
16	113,97	
17	112,2	

for which the tap changer position measuring is performed via mA input, with 4-20mA input signal the following settings are necessary to properly measure tap changer position:

24.6.1

Settings for MIM card

MIM card/input 1 settings:

OLTCOP = 1

NOOFPOS = 17

TSTABLE = 2.0

LEVPOS1 = 4.0mA

LEVPOSN = 20.0mA

MIM card/input 1 settings in SMSBASE:

MaxValue = 20

I_Max = 20

MinValue = 4

I_Min = 4;

24.6.2**Settings for voltage control function**

VCTR settings in the configuration:

POSTYPE = 2 (i.e. mA Card)

VCTR settings in SMSBASE:

LowVoltTap = 1

HighVoltTap = 17

24.6.3**Settings for differential function**

DIFP settings in the configuration:

POSTYPE = 2 (i.e. mA Card)

OLTC2W = 1 (i.e. Primary)

DIFP settings in SMSBASE or from HMI:

NoOfTaps = 17

RatedTap = 5

MinTapVoltage = 138.6kV

MaxTapVoltage = 112.2kV

The chapter "Requirements".

This chapter deals with the requirements for external equipment and functionality that RET 521 demands in order to work as intended.

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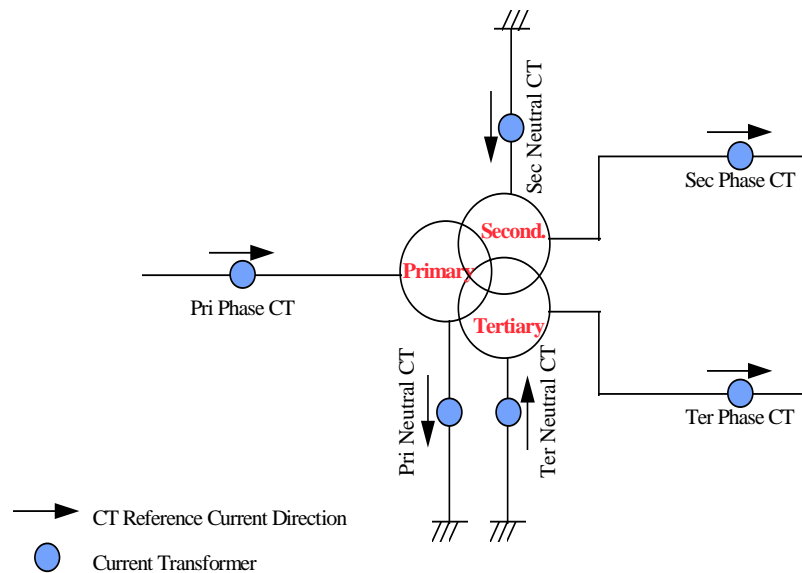
1

CT requirements

The performance of the transformer protection terminal will be dependent on the condition and quality of the signals fed to it.

The main CTs are always supposed to be star connected. The earthing of all CTs connected to the terminal have to be set under “Configuration” menu in the HMI or SMS. These settings are very important in order to enable RET 521 to measure and display the currents in accordance with its internal reference directions as shown on Fig. 1.

The other settings for CTs and VTs under the same “Configuration” menu should be properly set as well to enable RET 521 to use proper scaling factors for current and voltage magnitude measurements.



Definition:

CT Reference Current Direction = Current has a positive value when flows in the same direction with associated arrow

Fig. 1 RET 521 Internal Reference Directions for Current Transformers

The main CTs are supposed to be of type 5P, TPX, TPY or similar, but not airgapped (e. g. not TPZ), and should have saturation factors that satisfy the requirements below:

To avoid maloperation on energization of the power transformer and in connection with fault current that passes through the power transformer, the rated equivalent limiting secondary e.m.f., E_{al} , according to IEC 185 and IEC 44-6 should satisfy requirements (a) below:

$$E_{al} \geq 30 \cdot I_{nt} \cdot [R_{ct} + 2 \cdot R_l + Z_r] \quad (a)$$

Here I_{nt} is the main CT secondary current corresponding to rated primary current of the power transformer, R_{CT} is the secondary resistance of the main CT, R_l is the resistance of a single secondary wire from the main CTs to the relay, and Z_r is the burden of the relay.

To avoid maloperation in connection with fault current that passes through the power transformer, the rated equivalent limiting secondary e.m.f., E_{al} , should also satisfy requirement (b) below:

$$E_{al} \geq 2 \cdot I_{ff} \cdot [R_{CT} + 2 \cdot R_l + Z_r] \quad (b)$$

Here I_{ff} is the maximum secondary side fault current that pass two main CTs and the power transformer. Requirement (b) relates to the case when the transformation ratios are unequal and the case when the magnetisation characteristics are not equal.

In substations with breaker-and-a-half or double-busbar double-breaker arrangement, the fault current may pass two main CTs for the transformer differential protection without passing the power transformer. In such cases, the CTs must satisfy requirement (a) and the requirement (c) below:

$$E_{al} \geq I_f \cdot [R_{CT} + 2 \cdot R_l + Z_r] \quad (c)$$

Here I_f is the maximum secondary side fault current that passes two main CTs without passing the power transformer. Requirement (c) applies to the case when both main CTs have equal transformation ratio and magnetisation characteristics.

2 Remote communication

The terminal is provided with the following three serial ports:

- serial port on the front of the terminal. This port is always included in the delivery.
- serial port (optional) at the rear of the terminal, intended for connection to SMS.
- serial port (optional) at the rear of the terminal, intended for connection to SCS.

2.1 Hardware requirements

2.1.1 Front port

This port is intended for temporary connection of a PC. For this connection a special interface cable intended for this purpose must be used. For ordering No please refer to the for RET 521 technical overview brochure.

2.1.2**Ports at the rear of the terminal**

These ports are intended for connection of optical fibres and can be delivered for plastic or glass fibre.

Plastic fibre:

Connector: snap-in type

Glass fibre:

Connector: bayonet type ST

2.2**Software requirements****2.2.1****SMS**

- SMS BASE
- SM/RET 521*2.1
- CAP 531*1.3
- CAP/RET 531*2.1
- RECOM*2.0
- REVAL*2.0

3**Time synchronisation**

The real time clock in the RET 521 terminal can be synchronised in three different ways:

- via the SPA communication link normally from SMS
- via the LON communication link normally from SCS
- via minute pulses to a binary input.

Since the synchronisation via the serial buses is part of SCS and SMS and is harmonised with the terminal, the requirements on this synchronisation are not dealt with here.

The requirements on the minute pulses are:

- correct voltage according to the rating of the binary input
- the pulse must have a duration of minimum 5 ms and maximum 100 ms
- rise time maximum 1ms
- absolute bounce free pulse

The chapter "Configuration and settings".

This chapter deals with how the terminal can be configured and how to generate setting values. The different software tools that can be used is also presented.

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Introduction

The configuration of functions and logics in RET 521 is made from the configuration tool CAP 531. This tool can be connected either to the front of the terminal or to the rear SPA-port.

All parameter settings can be made in these ways:

- Locally, via the built-in human-machine interface (HMI) module.
- Locally, on a PC via the optical front connector, using SMS in the PC.
- Locally or remotely, via one of the ports on the rear, using SMS or SCS.

These software modules for configuration and setting are available for RET 521:

- The CAP/RET 521 software module is, together with the tool CAP 531, intended to configure the terminal RET 521 regarding function block and logic connections.
- The SM/RET 521 software module is part of SMS 010. SM/RET 521, together with the SMS BASE, is intended for parameter setting and supervision of the terminal RET 521.
- The HV/RET 521, included in the LIB 520 library, is intended for parameter setting and event handling, in MicroSCADA applications, of the terminal RET 521. That means the same information and functionality as for SM/RET 521, but in MicroSCADA applications.

The HV/Control software module, included in the MicroSCADA library LIB 520, is intended to be used for control functions in REx 5xx terminals. The software module includes a part regarding voltage control, which is intended to be used together with the voltage control function in RET 521. That part contains the process picture, dialogues and process database for the voltage control application in the MicroSCADA.

Configuration

1 CAP 531

1.1 Product overview

The Configuration and Programming tool **CAP 531** enables configuration management, programming, and error detection and correction for REx 5xx terminals.

The software module CAP/RET 521 is the CAP function library for a RET 521 terminal.

1.2 Operating environment

CAP 531 runs under Microsoft® Windows™ 3.1, 3.11, Windows 95 or Windows NT. So you must be familiar with these programs, which let you perform actions such as drag and drop, zoom, and scroll.

1.3 IEC 1131 programming

The IEC 1131 standard includes several graphical and textual programming languages. The CAP 531 function block diagram (FBD) is one of the IEC 1131 languages.

FBD is a graphical language. It is a widely used programming language that is used to create complicated networks with functions or function blocks. Networks are created with lines that connect or duplicate information.

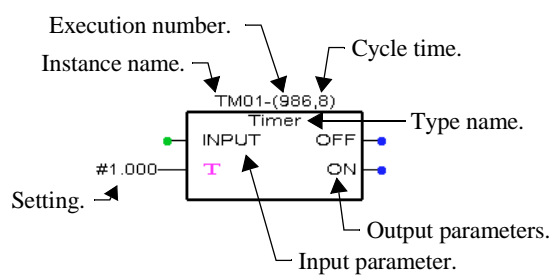


Fig. 1 Function block in the CAP 531 work sheet.

In CAP 531, all the functions in a terminal are called function blocks. A function block includes input and output parameters, a type name, and function block name. See Fig. ? .

A function that is represented as a function block in CAP 531 can be a:

- protection function
- control function
- monitoring function
- logic function

The instance name makes the function block unique. Cycle time is the time between executions (8 ms in Fig. ?).

Each function block has an execution number (986 in Fig. ?). The execution number tells you in which order the function blocks are executed.

Example: Function blocks with cycle time 8 ms are executed in the terminal every 8 ms and execution number 986 is executed after execution number 985. All function blocks with this cycle time are executed within a period of 8 ms.

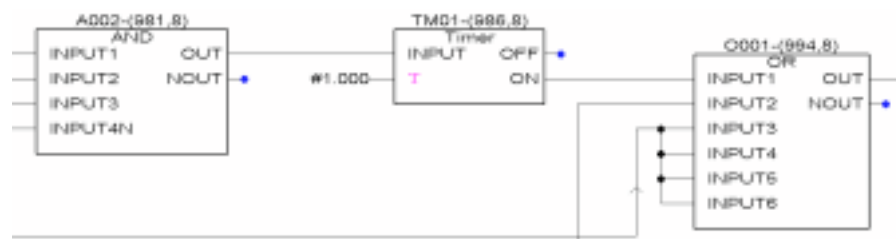


Fig. 2 Function block diagram.

Some settings are done in CAP 531. They are presented as inputs with magenta colour.

In Fig. ? the Timer function block has a setting of a delay time set to 1.000 seconds. A setting can be both numbers (as for a timer) or names.

Note !

Ensure that the function blocks in the configuration are executed consecutively to minimize delay. Select the logical function blocks (AND, OR etc.) in rising order, from left to right in the work sheet.



1.4**CAP 531 documentation**

The CAP 531 user's guide consists of these main parts:

Item:	Description:
Installation	Installation instruction.
Help	Instructions of how to use the help function.
Tutorial	Shows how to use CAP 531 with a mouse. Use this to learn how a project is run with CAP 531. The Tutorial goes through the normal procedures of a project.
Keyboard	Shows how to use CAP 531 with a keyboard.
General Project Tree Work Sheet Page Layout	Describes all parts of CAP 531. It contains the main topics in the context-sensitive help.

There is also an on-line context-sensitive help in the program. Press <F1> from anywhere in CAP 531 to get detailed reference information about all of CAP 531. The CAP/RET 521 is described in its corresponding user's guide. See also "Reference publications" on page 151.

Setting

2 SM/RET 521

2.1 Product overview

SM/RET 521 is intended for parameter setting and supervision of the corresponding RET 521 terminal. The SM/RET 521 software module is part of SMS 010, Station Monitoring System, hereafter simply denoted SMS.

The SMS consists of four functional parts:

- Parameter setting and supervision
- Disturbance recording evaluation
- Event handling
- Time synchronisation

Since SMS also supports communication via telephone modems this makes SMS a way to travel to the station by communication link, making physical presence in the station unnecessary.

2.2 Operating environment

The software runs on a PC system using the DOS operating system. The SMS-BASE is the platform program always required to run SM/RET 521 and other SM/... software modules.

2.3 Functionality

Terminal parameter setting and supervision, sometimes also called protection/control monitoring, lets the user display information and change settings from a PC in the same way as from the built-in HMI (Human-Machine-Interface) on the front of the terminal.

There are also information available only by using SM/RET 521, such as time tagged disturbance reports and event functions settings.

2.4

SM/RET 521 documentation

The SM/RET 521 user's manual consists of these main parts:

Item:	Description:
Installation	Installation instruction.
Basic operation	Shows the work flow for some typical tasks when using SM/RET/521, such as: <ul style="list-style-type: none">• How to communicate via the front port.• Change settings.• Read and write multiple parameters.• Setting time.• Storing of disturbance data.
Extensive operation	Presents all the possibilities that SM/RET 521 gives and the available functions. The menus that build up the product are presented with an explanation of the contents and how to operate them.

See also "Referenced publications" on page 65.

3

HV/RET 521

3.1

Product overview

HV/RET 521 is intended for parameter setting and event handling, in MicroSCADA applications, of the corresponding RET 521 terminal.

The HV/RET 521 software module is included in the LIB 520 high-voltage process package, which is a part of the Application Software Library within MicroSCADA applications. The information presented on the MicroSCADA screen is similar to the presentation of the Station Monitoring System (SMS).

The HV/RET 521 software consists of three functional parts:

- Read terminal information
- Change terminal settings
- Handling of spontaneous events for presentation in lists

3.2 Operating environment

The software runs on a PC system using operating system Windows/NT 4.0. To run the HV/RET 521 software, also the MicroSCADA packages MicroSYS rev. 8.4.1C, MicroTOOL rev. 8.4.1, LIB 500 rev. 4.0.1 and LIB 510 rev. 4.0.1 or later must be available.

3.3 Functionality

Protection parameter setting and supervision, sometimes also called protection monitoring, lets the user display information and change settings from a MicroSCADA system in the same way as from the built-in HMI (Human-Machine-Interface) on the front of the terminal.

There are also information available only by using HV/RET 521 and MicroSCADA, such as time tagged disturbance reports.

3.4 HV/RET 521 documentation

The HV/RET 521 user's manual consists of these main parts:

Item:	Description:
Installation	Installation instruction.
Tutorial	Shows the work flow for some typical tasks when using SM/RET/521, such as: <ul style="list-style-type: none">• Select function on the screen.• Screen presentation• Read and change settings.• Alternate between setting groups• Change of password• Diagnosing errors
Technical description	Gives an overview of all HV/RET 521 parts including a description of the screen contents.

See also "Referenced publications" on page 65.

4 HV/Control

4.1 Product overview

The HV/Control software module is intended to be used for control functions in REx 5xx terminals. The software module includes a part regarding voltage control, which is intended to be used together with the voltage control function in RET 521. That part contains the process picture, dialogues and process database for the voltage control application in the MicroSCADA.

The HV/Control software module is included in the LIB 520 high-voltage process package, which is a part of the Application Software Library within MicroSCADA applications.

The HV/Control software consists of these functional parts:

- HV General bay
- HV Breaker, Disconnecter and Earthing switch
- Overview Bay
- HV Measurement
- HV REx 5xx Supervision
- HV Voltage Control

HV Measurement, HV REx 5xx Supervision and HV Voltage Control can be used for RET 521.

4.2 Operating environment

The software runs on a PC system using operating system Windows/NT 4.0. To run the HV/Control software, also the MicroSCADA packages MicroSYS rev. 8.4.1C, Micro-TOOL rev. 8.4.1, LIB 500 rev. 4.0.1 or later must be available.

4.3 Functionality

HV/Control is used to handle control and supervision functions via a process picture in MicroSCADA applications. The control function consists of open/close commands of high-voltage apparatuses or raise/lower commands of tap changers including corresponding position indications. The commands are performed from a control dialogue window, which is automatically displayed when the device to be controlled is selected. Within the control dialogue also other features are available such as e.g. blocking functions and remote/station handling.

4.4 HV/Control documentation

The HV/Control user's manual consists of these main parts:

Item:	Description:
Installation	Installation instruction.
Tutorial	Describes the general functionality and graphical representation for these functions: <ul style="list-style-type: none">• HV General bay• HV Breaker, Disconnecter and Earthing switch• Overview Bay• HV Measurement• HV REx 5xx Supervision• HV Voltage Control
Appendix	Files, such as format pictures, dialogue pictures, text files and help files are listed here.

See also "Referenced publications" on page 65.

5 Human machine interface (HMI)

5.1 General

The built-in human machine interface (HMI) provides local communication between the user and the terminal.

The built-in HMI module is located on the front of the terminal and consists of three LEDs, an LCD display with four lines, each containing 16 characters, six buttons and an optical connector for PC communication.

5.2 Functionality

These main menus for status reading and parameter setting are available:

- **Disturbance report**, gives the user all information recorded by the terminal for the last 10 disturbances (optional).
- **Service report**, displays information about the operating conditions and information about the terminal.
- **Settings**, is used to set different parameters within the built-in functions.
- **Terminal status**, displays self supervision information and terminal ID.
- **Configuration**, is used to tailor the configuration of the terminal regarding e.g. communication, time synchronisation, identifiers (IDs). Configuration of functions is performed from the CAP 531 configuration tool.
- **Command**, is used to activate different output signals for performance of various commands in the terminal.
- **Test**, is used to make secondary injection testing of the terminal as easy as possible.

For more details, see Operators Manual.

6 Power transformer 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.

6.1 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 1: Basic transformer data, two winding transformer

Parameter description	Parameter name	Range	Default
Transformer Vector Group	VectorGroup 2W	See Fig. 1	Yy00
Rated Transformer Power in MVA	Sr	0.1-999.9	173.2

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

Table 2: Basic transformer data, three winding transformer

Parameter description	Parameter name	Range	Default
Transformer Vector Group	VectorGroup 3W	See Fig. 2	Yy00y00

6.1.1

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 correspondance 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 (Primary Winding)		W3 (Tertiary 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 (Primary Winding)		W3 (Tertiary 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

Fig. 4 Vector group reference table for three winding systems

99000003.ppt

6.2

Two winding transformer system

Primary winding data is set using the menu branch:

Settings**Functions****Group *n*****TransfData****Winding 1****Table 3: 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	1.0-999.9	100.0

Secondary winding data is set using the menu branch:

Settings**Functions****Group *n*****TransfData****Winding 2****Table 4: 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	1.0-999.9	100.0

6.3

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 5: Three winding transformer data, primary winding

Parameter Description	Parameter Name	Range	Default
Rated Power of Primary Winding in MVA	Sr1	0.1-999.9	173.2
Rated Current for Primary Winding in A	Ir1	1-99999	1000
Rated Phase to Phase Voltage for Primary Winding in kV	Ur1	1.0-999.9	100.0

Secondary winding data is set using the HMI menu branch:

Settings**Functions****Group *n*****TransfData****Winding 2****Table 6: Three winding transformer data, secondary winding**

Parameter Description	Parameter Name	Range	Default
Rated Power of Primary Winding in MVA	Sr2	0.1-999.9	173.2
Rated Current for Primary Winding in A	Ir2	1-99999	1000
Rated Phase to Phase Voltage for Primary Winding in kV	Ur2	1.0-999.9	100.0

Tertiary winding data is set using the HMI branch:

Settings**Functions****Group *n*****TransfData****Winding 3****Table 7: Three winding transformer data, secondary winding**

Parameter Description	Parameter Name	Range	Default
Rated Power of Primary Winding in MVA	Sr3	0.1-999.9	173.2
Rated Current for Primary Winding in A	Ir3	1-99999	1000
Rated Phase to Phase Voltage for Primary Winding in kV	Ur3	1.0-999.9	100.0

7

Current and voltage transformer data

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.

The following data need to be set for every voltage transformer connected to RET 521:

Table 8: Voltage transformer settings

Parameter description	Parameter name	Range	Default
Rated VT primary voltage in kV	VTprim	0.1-999.9	100
Rated VT secondary voltage in Volts	VTsec	1-999	100

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:

$$\text{VTprim} = 132 \text{ kV}$$

$$\text{VTsec} = 110 \text{ V}$$

The following data need to be set for every current transformer connected to RET 521:

Table 9: Current transformer settings

Parameter Description	Parameter name	Range	Default
Rated CT primary current in A	CTprim	1-99999	1000
Rated CT secondary current in A	CTsec	1-5	1
Used input tap for CT on AIM card	InputCTTap	Input 1A or Input 5A	Input 1A
Current transformer earthing (staring)	CTearth	Bus1, Tfr1, Neut1, Earth1, Bus23, Tfr23, Neut23, Earth23	Bus1

The first two parameters define the CT ratio.

The third 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 ?. It should be noted that this parameter can be only set from the built-in HMI.

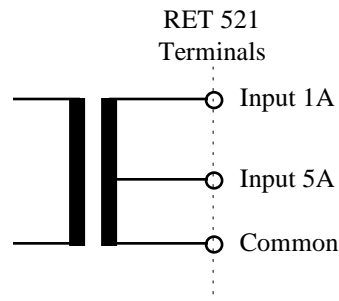


Fig. 5 CT Connections to RET 521

Parameter “*CTearth*” determines the way to configure according to the main CTs star connection and their polarity, or from RET 521 point of view, in which direction current is measured. Suffix 1 indicates primary side of the power transformer while suffix 2 or 3 indicates secondary or tertiary side of the power transformer.

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

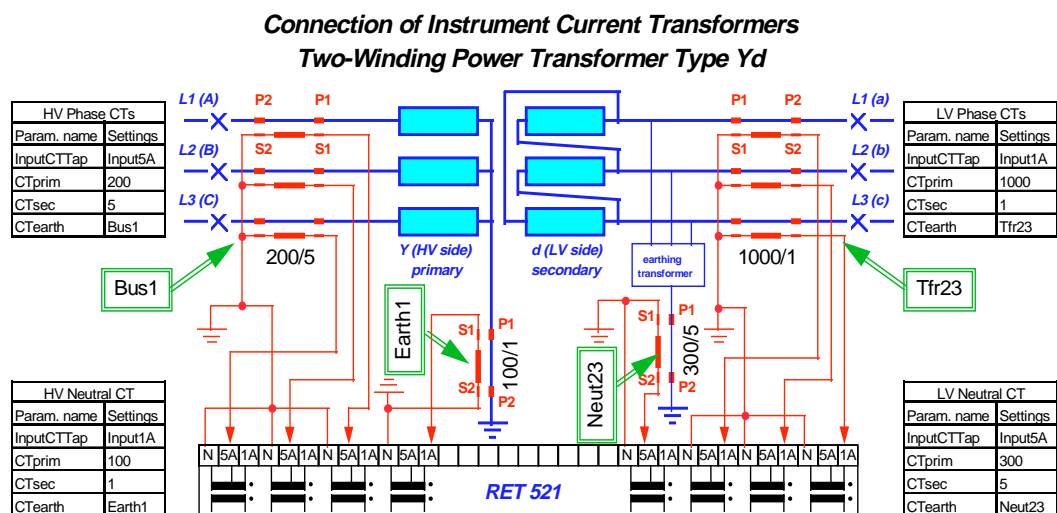


Fig. 6 CT Setup Example

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 eg 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.

However if the customer would like to have a customer defined setting of a protective function, which can be defined in the same configuration parameter Side2w or Side3w both the direction and the reference operate value has to be set and controlled by the customer himself.

Reference publications

User's Guide CAP 531*1.3 1MRK 511 056-UEN

User's Guide CAP/RET 521*2.1 1MRK 511 060-UEN*2.1-00

User's manual HV/Control*2.1 1MRK 511 061-UEN*2.1-00

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User's manual SM/RET 521*2.1 1MRK 511 063-UEN*2.1-00

User's Guide SMS BASE 1MRS 750 146-ESD

Technical Overview Brochure RET 521*2.1 1MRK 504 012-BEN

LNT 505, LON Configuration Tool, 1MRS 151 400

SLDT, LON configuration module REx 500, 1MRK 001 700-A

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ABB Automation Products AB
Division Substation Automation
Dept. TMD4
S-721 59 Västerås
Sweden