VAMP 210

Generator protection relay

Testing manual

Table of Contents

1. General

This guide is describes simple procedures to test the protection stages of generator protection relay VAMP 210 with firmware version 2.150. All test cases are calculated for single phase testing devices like Sverker 750 by Programma. Some test cases are also calculated for three-phase test device like Programma FREJA 300. The frequency stages need a test device capable to give adjustable frequency. Other stages can be tested with a fixed line frequency. There are precalculated examples for each type of protection.

1.1. Scaling

The CT and VT ratios, the nominal values of the generator and the prime mover are essential for the proper working of the VAMP 210. Most measurement and setting values are scaled to primary values or relative values against the generator nominal values, which makes the device easy to use and set. Unfortunately the same scaling makes secondary testing of the relay more complex because the scaling has to be decoded to find out the secondary signal levels for testing.

GENERATOR

- Generator nominal power [kVA]
- Nominal generator voltage [V]
- Prime mover nominal shaft power [kW]. This is used only by the reverse power stages. If this values is not available, set it equal to generator nominal power.

PHASE CURRENT TRANSFORMERS

- Nominal primary current of the CT. [A]
- Nominal secondary current of the CT. [A].
  Note: This may differ from the nominal input value of the device.

VOLTAGE TRANSFORMERS

- Nominal primary voltage of the VT. [V]
- Nominal secondary voltage of the VT. [V]
- Nominal secondary voltage of the residual VT. [V]

RESIDUAL CURRENT TRANSFORMERS

- Nominal primary current of the CT for I_{01} input. [A]
- Nominal secondary current of the CT for I_{01} input. [A]
  Note: This may differ from the nominal input value of the device.

- Nominal primary current of the CT for I_{02} input. [A]
- Nominal secondary current of the CT for I_{02} input. [A] Note: This may differ from the nominal input value of the device.

UNIT TRANSFORMER

- No/Yes. Is there a unit transformer between VTs and CTs or not?
- Bus bar nominal voltage. [V]
- Generator side nominal voltage. [V]
- Compensation for the connection group of the transformer in degrees. E.g. For a YNd11[1] transformer the ConGrp equals +30° i.e. the generator voltage (secondary) leads the high voltage side (primary) voltage by 30°. The compensation angle is thus –30° for YNd11. (Firmware version 2.153)

[1] Explanation of the transformer connection group code YNd11:
Y Capital letter (Y, D or Z) defines the high voltage primary side connection.
N The neutral point is available.
d Lower case letter (y, d or z) defines the low voltage secondary side connection.
11 The watch dial hour number defines the line voltage phase shift from primary to secondary. 0 h = 0°, 1 h = –30°,
2 h = –60°, 3 h = –90°, .. 6 h = 180°, 7 h = +150°, .. 10 h = +60°, 11 h = +30°.

YNd11 means that the high voltage primary side is connected to wye the neutral point being available and the low voltage secondary side is connected to delta. The secondary voltage leads the primary voltage by 30°.
Dyn1 means that the high voltage primary side is connected to delta and the low voltage secondary side is connected to wye. The neutral point is available. The secondary voltage lags the primary voltage by 30°.

2. Rear panel connectors

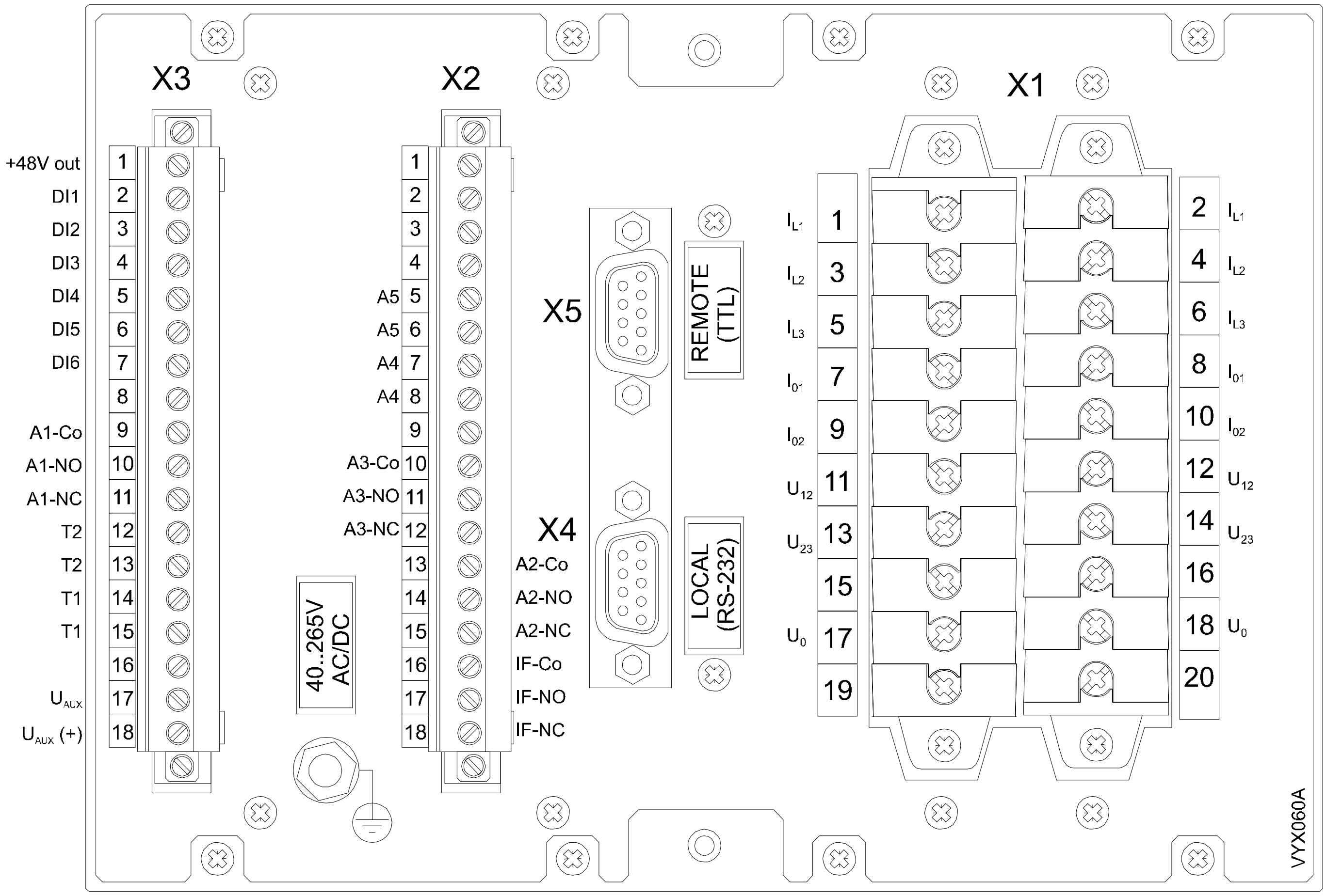

Figure 2-1 The rear panel of VAMP 210

3. Correct phase order of currents and voltages

3.1. Phase order of currents and voltages

1. The correct phase order of the two line voltages is essential to the device to be able to measure positive sequence voltage U_1. E.g. under voltage protection and blocking of under frequency protection are based on the positive sequence voltage U_1.
2. The phase order of the three currents must be equal with the line voltages in order to the device to be able measure active and reactive power.
3. The polarity of voltages and currents has to be correct.

You can check the phase order by giving the operator or configurator password (default = 1) and selecting the screen **PHASE SEQUENCES** under main menu **MEAS**. There are two lines: **I** showing the rotation direction of phase currents and **U** showing the rotation direction of main voltages. Both should have value 1.
The meaning of the values is:

0	No signal. The device is unable to solve the phase order.
1	The phase order is correct.
-1	The phase order is incorrect!

Note: If one of the inputs has reversed polarity **and** the phase sequence is reverse, then the resulting galloping phase sequence is misleadingly correct. See Figure 3.1-1.
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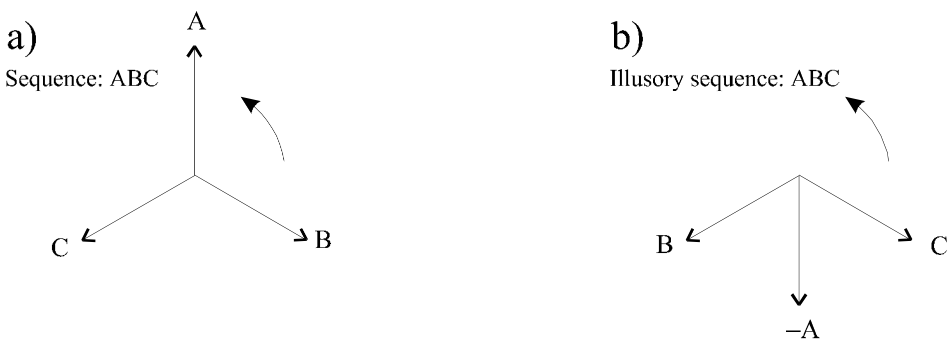

Figure 3.1-1 a) Correct polarities and phase sequence. b) One incorrect polarity and incorrect phase sequence. Due to the one wrong polarity, the incorrect phase sequence is seemingly OK.

4. Adapting the local frequency

The VAMP 210 needs to know the local line frequency to be able to take 2^N samples/cycle. The frequency is determined from signals connected to voltage inputs U_{12} and/or U_{23}. Testing e.g. I> 50/51 function right after unpacking the relay will not give precise results because the relay is not able to detect the local line frequency from current measurement only. In this case a new relay needs to acquaint itself with the local line frequency. This is done by connecting a voltage of 50 .. 130 Vac of the local line frequency into U_{12} or U_{23} input of the relay for time of one minute.

If testing includes voltage signals to U_{12} or U_{23} inputs the relay is immediately ready to operate. The one-minute adaptation time is only needed to set the default frequency, which is used only when no voltage signal exists (like testing overcurrent protection of a just unpacked relay with current injection only).

5. Overcurrent stage I>, ANSI 50/51

5.1. Trip level test

Overcurrent settings are relative the generator nominal current I_{GEN}. The relay is using equation 5-1 to calculate I_{GEN} from the given nominal generator power S_{GEN} and nominal generator voltage U_{GEN}. (All the symbols like I_{GEN} are listed in chapter 18.)

equation 5-1

$$I_{GEN} = \frac{S_{GEN}}{\sqrt{3}U_{GEN}}$$

On secondary side the nominal generator current will be

equation 5-2

$$I_{GenSec} = I_{GEN} \frac{I_{CTSEC}}{I_{CTPRI}},$$ where

I_{CTPRI}	=	Nominal primary of the CT
I_{CTSEC}	=	Nominal secondary of the CT

Formula to calculate primary pick up current.

equation 5-3

$$I_{SetPri} = I_{SET} \cdot I_{GEN}$$

Formula to calculate secondary pick-up current.

equation 5-4

$$I_{INJ} = I_{SetPri} \frac{I_{CTSEC}}{I_{CTPRI}}$$

Example 5-1

S_{GEN}	=	5134 kVA
U_{GEN}	=	13800 V
I_{SET}	=	1.2 xI_{GEN}
I_{CTPRI}	=	250 A
I_{CTSEC}	=	5 A
Delay type	=	DT Definite time
t	=	0.10 s Set definite operation time to it's minimum to make the test easier.

Generator nominal current (equation 5-1)
I_{GEN} = 5134000 VA/(√3 x 13800 V) = 214.79 A

Pick up current on primary side (equation 5-3)
I_{SetPri} = 1.2 x 214.79 A = 257.75 A

Injected secondary current, which should start the protection stage (equation 5-4)
I_{INJ} = 257.75 A x 5/250 = **5.15 A**

The actual pick up current should be within ±2% = 5.05 .. 5.26 A. To find out the actual pick up level start with current 5.00 A. Then increase the injection in small steps until the relay picks up.

Table 1. Testing pick up level of I> 50/51 stage.

Secondary injection to I_{L1}, I_{L2}, I_{L3} or any combination	5.15 A
The relay should not pick up before	5.05 A
The relay should pick up before	5.26 A
actual pick up level in amps	
ok/fail	

Example 5-2

S_{GEN} = 8000 kVA
U_{GEN} = 6300 V
I_{SET} = 3.0 xI_{GEN}
I_{CTPRI} = 1000 A
I_{CTSEC} = 1 A
Delay type = DT Definite time
t = 0.10 s Set definite operation time to it's minimum to make the test easier.

Generator nominal current (equation 5-1)
I_{GEN} = 8000000 VA/(√3 x 6300 V) = 733.14 A

Pick up current on primary side (equation 5-3)
I_{SetPri} = 3.0 x 733.14 A = 2199.4 A

Injected secondary current, which should start the protection stage (equation 5-4)
I_{INJ} = 2199.4 A x 1/1000 = **2.20 A**

The actual pick up current should be within ±2% = 2.16 .. 2.24 A. To find out the actual pick up level start with current 2.10 A. Then increase the injection in small steps until the relay picks up.

Table 2. Testing pick up level of I> 50/51 stage.

Secondary injection to I_{L1}, I_{L2}, I_{L3} or any combination	2.20 A
The relay should not pick up before	2.16 A
The relay should pick up before	2.24 A
actual pick up level in amps	
ok/fail	

5.2. Operation delay test

5.2.1. Definite operation time

The specified operation time accuracy is achieved when the fault current is >200% of the setting value.

Example 5-3

S_{GEN} = 8000 kVA
U_{GEN} = 6300 V
I_{SET} = 1.0 xI_{GEN}
I_{CTPRI} = 800 A
I_{CTSEC} = 5 A
Delay type = DT Definite time
t = 0.10 s Definite operation time

Generator nominal current (equation 5-1)
I_{GEN} = 8000000 VA/(√3 x 6300 V) = 733.14 A

Pick up current on primary side (equation 5-3)
I_{SetPri} = 1.0 x 733.14 A = 733.14 A

Secondary current corresponding the trip level (equation 5-4)
I_{SetSec} = 733.14 A x 5/800 = 4.5821 A

The specified operation time accuracy is achieved when the injected current is >200% of the setting value.
I_{INJ} = 2.04 x 4.5821 A = **9.26 A** (200% + tolerance 2% yields to multiplier 2.02)

The operation time including the inertia of the output relay should be within ±30 ms: 70 .. 130 ms.

Table 3. Testing definite operation time of I> 50/51 stage.

Secondary injection to I_{L1}, I_{L2}, I_{L3} or any combination	step 0 ⇒ 9.26 A
The relay should not pick up before	70 ms
The relay should pick up before	130 ms
actual pick up time	
ok/fail	

5.2.2. Inverse operation time

There are four types of inverse time delay characteristics. The formulae for each type are:

NI = normal inverse.

equation 5-5

$$t_{NI} = \frac{0.14k}{\left(\frac{I_{INJ}}{I_{SetSec}}\right)^{0.02} - 1}, \qquad \text{where}$$

I_{INJ} = injected current to the relay

I_{SetSec} = setting value scaled to CT secondary side

VI = very inverse.

equation 5-6

$$t_{VI} = \frac{13.5k}{\frac{I_{INJ}}{I_{SetSec}} - 1}$$

EI = extremely inverse.

equation 5-7

$$t_{EI} = \frac{80k}{\left(\frac{I_{INJ}}{I_{SetSec}}\right)^{2} - 1}$$

LTI = long time inverse.

equation 5-8

$$t_{LTI} = \frac{120k}{\frac{I_{INJ}}{I_{SetSec}} - 1}$$

Example 5-4

S_{GEN}	=	8000 kVA
U_{GEN}	=	6300 V
I_{SET}	=	1.0 xI_{GEN}
I_{CTPRI}	=	1000 A
I_{CTSEC}	=	5 A
Delay type	=	NI Normal inverse
k	=	0.50 Inverse time multiplier

Generator nominal current (equation 5-1)
I_{GEN} = 8000000 VA/(√3 x 6300 V) = 733.14 A

Pick up current on primary side (equation 5-3)
I_{SetPri} = 1.0 x 733.14 A = 733.14 A

Secondary current corresponding the trip level(equation 5-4)
I_{SetSec} = 733.14 A x 5/1000 = 3.6657 A

We select the injected current to be I_{INJ} = 1.8 x I_{SetSec}. Then the injected current should be
I_{INJ} = 1.8 x I_{SetSec} = **6.60 A**

The operation time t_{NI} will be according equation 5-5
t_{NI} = $0.14 \times 0.5/((6.60/3.6657)^{0.02} - 1)$ = **5.92 s**

The operation time including the inertia of the output relay should be within ±5%: 5.62 .. 6.21 s.

Table 4. Testing normal inverse operation time of I> 50/51 stage.

Secondary injection to I_{L1}, I_{L2}, I_{L3} or any combination	step 0 ⇒ 6.60 A
The relay should not pick up before	5.62 s
The relay should pick up before	6.21 s
actual pick up time	
ok/fail	

Example 5-5

Delay type	=	VI Very inverse
k	=	0.10 Inverse time multiplier

Other setting is same as in Example 5-4.

We select the injected current to be **13.2 A**, twice the current of Example 5-4. The operation time t_{VI} will be according equation 5-6
t_{VI} = 13.5 x 0.1/((13.2/3.6657) – 1) = **519 ms**

The operation time including the inertia of the output relay should be within ±5%: 493.. 545 ms.

Table 5. Testing very inverse operation time of I> 50/51 stage.

Secondary injection to I_{L1}, I_{L2}, I_{L3} or any combination	step 0 ⇒ 13.2 A
The relay should not pick up before	493 ms
The relay should pick up before	545 ms
actual pick up time	
ok/fail	

Example 5-6

Delay type = EI <u>Extremely inverse</u>

Other setting is same as in Example 5-4.

We select the injected current to be **6.60 A** as in Example 5-4. The operation time t_{EI} will be according equation 5-7

t_{EI} = 80 x 0.5/((6.60/3.6657)^2 – 1) = **17.8 s**

The operation time including the inertia of the output relay should be within ±5%: 16.9 .. 18.7 s.

Table 6. Testing extremely inverse operation time of I> 50/51 stage.

Secondary injection to I_{L1}, I_{L2}, I_{L3} or any combination	step 0 ⇒ 6.60 A
The relay should not pick up before	16.9 s
The relay should pick up before	18.7 s
actual pick up time	
ok/fail	

Example 5-7

Delay type = LTI Long time inverse

Other setting is same as in Example 5-4. We select the injected current to be **13.2 A**, twice the current of Example 5-4. The operation time t_{LTI} will be according equation 5-8

t_{LTI} = 120 x 0.5/(13.2/3.6657 – 1) = **23.1 s**

The operation time including the inertia of the output relay should be within ±5%: 21.9 .. 24.2 s.

Table 7. Testing long time inverse operation time of I> 50/51 stage.

Secondary injection to I_{L1}, I_{L2}, I_{L3} or any combination	step 0 ⇒ 13.2A
The relay should not pick up before	21.9 s
The relay should pick up before	24.2 s
actual pick up time	
ok/fail	

6. Overcurrent stage I_V>, ANSI 51V

This stage has a dynamic setting level depending on the actual positive sequence voltage. The dependency is quite freely configurable: Both restrained mode and controlled mode are possible. See Figure 6.1-1 and the other pictures of this chapter for more details. The operation delay is definitive.

6.1. Trip level test

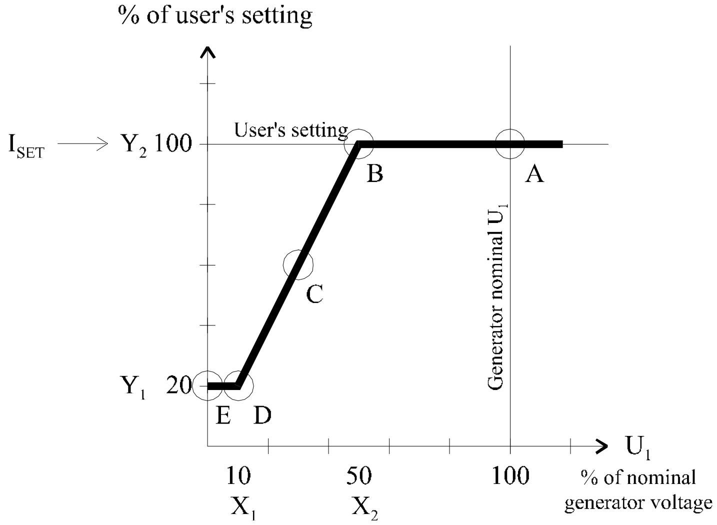

Figure 6.1-1 Example of dynamic setting value of the I_V> 51V overcurrent protection stage. When voltage drops below 50% the actual setting value starts to decrease. The co-ordinates X_1, X_2, Y_1 and Y_2 define the characteristics, which in this case is called voltage restrained. The marks A .. E are referring to the test example.

The secondary voltage corresponding the nominal generator line voltage is

equation 6-1

$$U_{GenSec} = U_{GEN} \frac{U_{VTSEC}}{U_{VTPRI}} \cdot \frac{U_{TraBB}}{U_{TraGen}}$$

If there is no unit transformer between VT and CT the transformer nominal primary and secondary voltages should be omitted, i.e.

U_{TraBB} = 1

U_{TraGen} = 1

The absolute positive sequence is calculated from the phase voltages U_{L1}, U_{L2} and U_{L3} as follows:

equation 6-2

$$\overline{U}_{1ABS} = \frac{\overline{U}_{L1} + \overline{a} \cdot \overline{U}_{L2} + \overline{a}^2 \cdot \overline{U}_{L3}}{3}$$

$$\overline{a} = 1\angle 120°$$

'a' is a unit phasor at angle 120 degrees. Multiplying a phasor with 'a' turns the original phasor 120 degrees counter clockwise. Multiplying a phasor with 'a^2' turns the original phasor 240 degrees counter clockwise (or 120 degrees clockwise).
Corresponding equation to calculate the absolute positive sequence using line voltages U_{23} and U_{31} is:

equation 6-3

$$\overline{U}_{1ABS} = \frac{\overline{U}_{12} - \overline{a}^2 \cdot \overline{U}_{23}}{3}$$

The relative positive sequence voltage will be:

equation 6-4

$$\overline{U}_1 = \frac{U_{1ABS}}{U_{SEC}} \cdot \sqrt{3}$$

where U_{SEC} is the secondary voltage corresponding the nominal generator line voltage (equation 6-1).

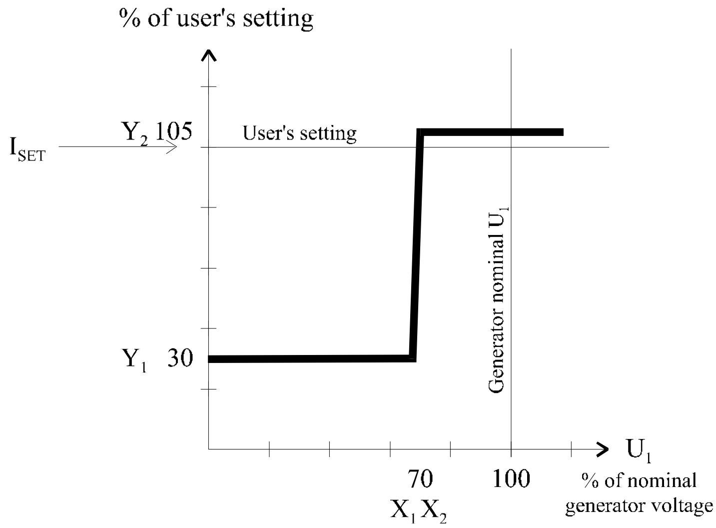

Figure 6.1-2 Voltage controlled mode. When voltage drops below 70% the actual setting values drops from 105 % to 30% of the user's setting. Note: The relay doesn't accept x_1, which is greater than or equal to x_2.

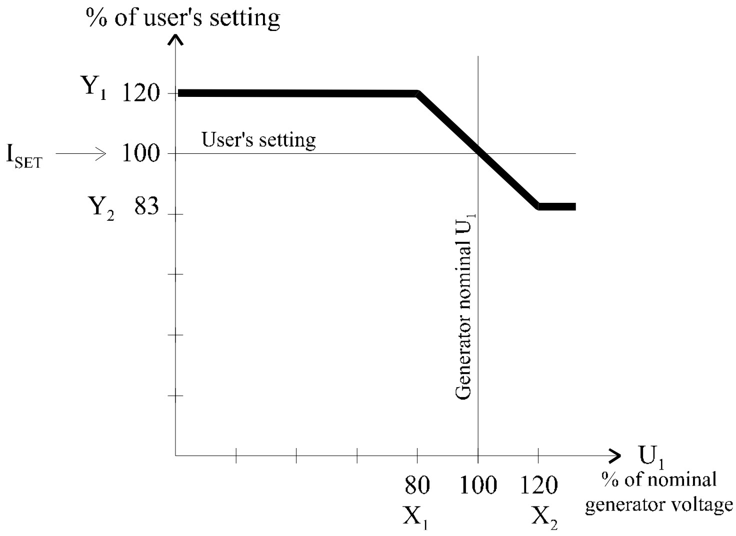

Figure 6.1-3 "Power limit" mode. When voltage drops from the nominal the actual setting values starts to increase and vice versa.

Example 6-1

S_{GEN}	=	5134 kVA
U_{GEN}	=	13800 V
I_{SET}	=	1.2 xI_{GEN}
I_{CTPRI}	=	250 A
I_{CTSEC}	=	5 A
U_{VTPRI}	=	15000 V
U_{VTSEC}	=	110 V
x_1	=	10% Relative start value of the controlling positive sequence voltage U_1. See Figure 6.1-1.
x_2	=	50% Relative stop value of the controlling positive sequence voltage U_1.
y_1	=	20% Relative start multiplier for the setting value I_{SET}.
y_2	=	100% Relative stop multiplier for the setting value I_{SET}.
t	=	0.10 s Set definite operation time to it's minimum to make the test easier.

No unit transformer

In this example we will statically test the five points A..E of the characteristics as drawn in the Figure 6.1-1.

Let us calculate the relative positive sequence voltage when the injected voltages are U_{12} = 100 V and U_{23} = 0 V.

U_{SEC} = 13800 x 110 V x 1/(15000 x 1) = 101.20 V (equation 6-1)

U_{1ABS} = (100 – a^2 x 0)/3 = 33.333 V(equation 6-3)

U_1 = 33.333/101.20 x √3 = 0.57050 = 57 % (equation 6-4)

Thus a single injected voltage, which corresponds to a 100% positive sequence voltage in this example, is

$U_{INJ100\%}$ = 100/0.57050 = 175.28 V

This voltage corresponds to 100% of the generator nominal U_1 voltage. See point A in Figure 6.1-1. However this voltage is too high for the line voltage input and nominal U_1 voltage cannot be achieved with single-phase supply.

Generator nominal current (equation 5-1)

I_{GEN} = 5134000 VA/(√3 x 13800 V) = 214.79 A

Point B

U_{INJ} = 0.50 x 175.28 V = **87.6 V**

This voltage corresponds to 50% of the generator nominal U_1 voltage. See point B in Figure 6.1-1.

Pick up current on primary side (equation 5-3)

I_{SetPri} = 1.2 x 214.79 A = 257.75 A

Injected secondary current, which should start the protection stage at point B (equation 5-4)

I_{INJ} = 257.75 A x 5/250 = **5.15 A**

The actual pick up current at point B should be within ±2% = 5.05 .. 5.26 A. To find out the actual pick up level start with current 5.00 A. Then increase the injection in small steps until the relay picks up.

Point C

U_{INJ} = 0.30 x 175.28 V = **52.6 V**

This voltage corresponds to 30% of the generator nominal U_1 voltage. See point C in Figure 6.1-1.

Injected secondary current, which should start the protection stage at point C, is 60% of the user's setting value:

I_{INJ} = 0.60 x 5.15 A = **3.09 A**

The actual pick up current at point C should be within ±2% = 3.03 .. 3.15 A. To find out the actual pick up level start with current 3.00 A. Then increase the injection in small steps until the relay picks up.

Point D

U_{INJ} = 0.10 x 175.28 V = **17.5 V**

This voltage corresponds to 10% of the generator nominal U_1 voltage. See point D in Figure 6.1-1.

Injected secondary current, which should start the protection stage at point D, is 20% of the user's setting value:

I_{INJ} = 0.20 x 5.15 A = **1.03 A**

The actual pick up current at point D should be within ±2% = 1.01 .. 1.05 A. To find out the actual pick up level start with current 0.96 A. Then increase the injection in small steps until the relay picks up.

Point E

U_{INJ} = 0 V

See point E in Figure 6.1-1.

Injected secondary current, which should start the protection stage at point E, is still 20% of the user's setting value:

I_{INJ} = 0.20 x 5.15 A = **1.03 A**

The actual pick up current at point D should be within ±2% = 1.01 .. 1.05 A. (Just the same as for point D.)

Table 8. Testing pick up level of I_V> 51V stage

	Point according Figure 6.1-1			
	B	C	D	E
Secondary injection to I_{L1}, I_{L2}, I_{L3} or any combination	5.15 A	3.09 A	1.03 A	1.03 A
Secondary injection to U_{12}	87.6 V	52.6 V	17.5 V	0 V
The relay should not pick up before	5.05 A	3.03 A	1.01 A	1.01 A
The relay should pick up before	5.26 A	3.15 A	1.05 A	1.05 A
actual pick up value in amps				
ok/fail				

6.2. Operation delay test

The specified operation time accuracy is achieved when the fault current is >200% of the setting value.

Example 6-2

t = 0.50 s

Other settings are same as in Example 6-1.

U_{INJ} = 100 V

This voltage corresponds to 57% of the generator nominal U_1 voltage as calculated in example 6-1 and in the curve of Figure 6.1-1 this value yields to a point somewhere between marked points B and A. Thus the dynamic setting will be equal to the user setting of 1.2 x I_{GEN}.

Injected secondary current, which exceeds the setting value by 202% at point A

I_{INJ} = 2.02 x 5.15 A = 10.4 A

The operation time including the inertia of the output relay should be within ±30 ms: 470 .. 530 ms.

Table 9. Testing definite operation time of I_V> 51V stage.

Secondary injection to I_{L1}, I_{L2}, I_{L3} or any combination	step 0 ⇒ 10.4 A
Secondary injection to U_{12} input	100 V
The relay should not pick up before	470 ms
The relay should pick up before	530 ms
actual pick up time	
ok/fail	

7. Unbalance current stage I_2>, ANSI 46

The negative sequence is calculated from the phase currents I_{L1}, I_{L2} and I_{L3} as follows:

equation 7-1

$$\overline{I}_2 = \frac{\overline{I}_{L1} + \overline{a}^2 \cdot \overline{I}_{L2} + \overline{a} \cdot \overline{I}_{L3}}{3}$$

$$\overline{a} = 1\angle 120^\circ$$

'a' is a unit phasor at angle 120 degrees. Multiplying a phasor with 'a' turns the original phasor 120 degrees. Multiplying a phasor with 'a^2' turns the original phasor 240 degrees.

7.1. Trip level test

Example 7-1

S_{GEN}	=	5134 kVA
U_{GEN}	=	13800 V
I_{2SET}	=	8% xI_{GEN}
I_{CTPRI}	=	250 A
I_{CTSEC}	=	5 A
Delay type	=	DT Definite time
t	=	1.0 s Set definite operation time to it's minimum to make the test easier.

Generator nominal current (equation 5-1)

I_{GEN} = 5134000 VA/(√3 x 13800 V) = 214.79 A

Pick up current I_{2SET} scaled to primary side (equation 5-3):

I_{SetPri} = 0.08 x 214.79 = 17.181 A

Pick up current I_{2SET} scaled to secondary side (equation 5-4)

I_{SetSec} = 17.181 x 5/250 = 0.34362 A

When injecting only one phase current the I_2 will be according equation 7-1:

I_2 = $I_{INJ}/3$

To get the amount of I_{2SET} of negative sequence current we have to supply the following secondary current one and only one input I_{L1}, I_{L2} or I_{L3} (equation above and equation 7-1):

I_{INJ} = 3 x 0.34362 = **1.03 A**

This current corresponds to 8% of I_2.

The actual pick up current should be within ±3% = 1.00 .. 1.06 A. To find out the actual pick up level start with current 0.95 A. Then increase the injection in small steps until the relay picks up.

Table 10. Testing pick up level of I_2> 46 stage

Secondary injection to one of I_{L1}, I_{L2} or I_{L3}	1.03 A
The relay should not pick up before	1.00 A
The relay should pick up before	1.06 A
actual pick up level in amps	
ok/fail	

7.2. Operation delay tests

7.2.1. Definite operation time

The specified operation time accuracy is achieved when the I_2 unbalance current is >200% of the setting value.

Example 7-2

Delay type = DT Definite time

t = 1.0 s

Other settings are same as in Example 7-1.

I_{INJ} = 2.03 x 1.03 A = **2.09 A** (200% + tolerance 3% yields to multiplier 2.03)

The operation time including the inertia of the output relay should be within ±300 ms: 0.70 .. 1.30 s.

Example 7-3

Delay type = DT Definite time

t = 10.0 s

Other settings are same as in Example 7-1.

The operation time including the inertia of the output relay should be within ±5%: 9.50 .. 10.50 s.

Table 11. Testing definite operation time of I_2> 46 stage

	t = 1.0 s Example 7-2	t = 10.0 s Example 7-3
Secondary injection to one of I_{L1}, I_{L2} or I_{L3}	step 0 ⇒ 2.09 A	step 0 ⇒ 2.09 A
The relay should not pick up before	0.70 s	9.50 s
The relay should pick up before	1.30 s	10.50 s
actual pick up time		
ok/fail		

7.2.2. Inverse operation time

The operation delay is calculated as follows:

equation 7-2

$$t_{I2} = \frac{K_1}{\left(\frac{I_2}{I_{GEN}}\right)^2 - I_{2SET}^2}$$

K_1 = Generator constant for unbalance

I_2 = Measured negative sequence current

I_{GEN} = Generator nominal current

I_{2SET} = Maximum relative permitted continuous unbalance

Example 7-4

Delay type = INV Inverse time

K_1 = 2 s

Let's use injection current of

I_{INJ} = 5.85 A

The corresponding negative sequence current will be (equation 7-1):

I_{2SEC} = $I_{INJ}/3$ = 1.9500 A

Scale the I_{2SEC} to primary side

I_2 = 1.9500 x 250/5 = 97.500 A

Generator nominal current (equation 5-1)

I_{GEN} = 5134000 VA/(√3 x 13800 V) = 214.79 A

The operation time according equation 7-2 will be

t_{I2} = $2/((97.500/214.79)^2 - 0.08^2)$ = 10.02 s

The operation time including the inertia of the output relay should be within ±5%: 9.52 .. 10.52 s.

Table 12. Testing inverse operation time of I_2> 46 stage

Secondary injection to one of I_{L1}, I_{L2} or I_{L3}.	step 0 ⇒ 5.85 A
The relay should not pick up before	9.52 s
The relay should pick up before	10.52 s
actual pick up time	
ok/fail	

8. Residual current stage I_0>, ANSI 51N

There are two residual current inputs in the device. This stage is using the input I_{01}.

The residual current setting is a per unit (p.u.) value of the residual CT nominal value.

Formula to calculate secondary residual pick-up current:

equation 8-1

$$I_{INJ} = I_{0SET} \cdot I_{CToSEC}$$

8.1. Trip level test

Example 8-1

I_{CToSEC} = 5 A

I_{0SET} = 0.020 p.u.

t 0.10 s Set definite operation time to it's minimum to make the test easier.

The secondary pick up current will be (equation 8-1)

I_{INJ} = 0.020 x 5 A = 0.100 A

The actual pick up current should be within ±15 mA = 0.085 .. 0.115 A. To find out the actual pick up level start with current 0.08 A. Then increase the injection in small steps until the relay picks up.

Table 13. Testing pick up level of I_0> 51N stage

Secondary injection to I_{01} input	0.100 A
The relay should not pick up before	0.085 A
The relay should pick up before	0.115 A
actual pick up level in amps	
ok/fail	

8.2. Operation delay test

The specified operation time accuracy is achieved when the current is >200% of the setting value.

Example 8-2

t = 0.50 s

Other settings are same as in Example 8-1.

Injected secondary current which exceeds the setting value by 100% + 15 mA.

I_{INJ} = 2.00 x 0.100 A + 15 mA = **0.215 A**

The operation time including the inertia of the output relay should be within ±30 ms: 470 .. 530 ms.

Table 14. Testing definite operation time of I_0> 51N stage

Secondary injection to I_{01} input	step 0 ⇒ 0.215 A
The relay should not pick up before	470 ms
The relay should pick up before	530 ms
actual pick up time	
ok/fail	

9. Directional earth fault stage I_{0Dir}>, ANSI 67N

There are two residual current inputs in the device. This stage is using the input I_{01}.
Directional residual current function is using residual voltage to solve the direction. There are two modes: resistive and capacitive. The resistive mode is for resistance-earthed networks and the capacitive mode is for isolated networks. The mode can be pre-selected or it can be dynamically controlled by any digital input.
The residual current setting is a per unit (p.u.) value of the residual CT nominal value.

9.1. Trip level test

Example 9-1

U_{VT0SEC}	=	110 V
I_{CT0SEC}	=	5 A
I_{0SET}	=	0.10 p.u.
t	=	0.10 s Set definite operation time to it's minimum to make the test easier.
ChCtrl	=	Res The relay is sensitive to resistive component of the residual current.
U_{0MIN}	=	10% Minimum residual voltage for the stage to operate.

The secondary pick up current will be (equation 8-1)

I_{INJ} = 0.10 x 5 A = **0.500 A**

Minimum residual voltage for the stage to operate is

$U_{0MinInj}$ = U_{0MIN} x U_{VT0SEC} = 0.10 x 110 V = 11.0 V

The injected voltage should be more, e.g. 10%, than the minimum to ensure precise operation of the stage.

U_{INJ} = 1.1 x 11.0 V = **12.1 V**

The phase angles of the injected current and voltage must be equal.

The actual pick up current should be within ±3% = 0.485 .. 0.515 A. To find out the actual pick up level start with current 0.470 A. Then increase the injection in small steps until the relay picks up.

Table 15. **Testing pick up level of I_{0DIR}> 67N stage**

Secondary injection to U_0 input	12.1 V
Secondary injection to I_{01} input	0.5000 A
The relay should not pick up before	0.485 A
The relay should pick up before	0.515 A
actual pick up level in amps	
ok/fail	

9.2. Operation delay test

The specified operation time accuracy is achieved when the current is >200% of the setting value.

Example 9-2

t = 0.50 s

Other settings are same as in Example 9-1.

U_{INJ} = 12.1 V

This voltage corresponds to 100% of the generator nominal U_1 voltage. See point A in Figure 6.1-1. Switch this voltage on before the injected current step.

Injected secondary current, which exceeds the setting value by 103%.

I_{INJ} = 2.03 x 0.500 A = 1.02 A

The operation time including the inertia of the output relay should be within ±30 ms: 470 .. 530 ms.

Table 16. **Testing definite operation time of I_{0DIR}> 67N stage**

Secondary pre-injection to U_0 input	12.1 V
Secondary injection to I_{01} input	step 0 ⇒ 1.02 A
The relay should not pick up before	470 ms
The relay should pick up before	530 ms
actual pick up time	
ok/fail	

10. Residual overvoltage stage U_0>, ANSI 59N

10.1. Trip level test

Residual overvoltage settings are relative the broken delta VT nominal secondary voltage.

Formula to calculate secondary pick-up voltage.

equation 10-1

$$U_{INJ} = U_{SET} \cdot U_{VToSEC}$$

Example 10-1

U_{VToSEC} = 110 V

U_{SET} = 10%

t = 0.3 s Set definite operation time to it's minimum to make the test easier.

Injected secondary residual voltage that should start the protection stage (equation 10-1)

U_{INJ} = 0.10 x 110 = 11.0 V

The actual pick up voltage should be within ±2% = 10.8 .. 11.2 V. To find out the actual pick up level start with voltage 10.5 V. Then increase the injection in small steps until the relay picks up.

Table 17. Testing pick up level of U_0> 59N stage

Secondary injection to U_0 input	11.0 V
The relay should not pick up before	10.8 V
The relay should pick up before	11.2 V
actual pick up level in amps	
ok/fail	

10.2. Operation delay test

The specified operation time accuracy is achieved when the fault voltage is >200% of the setting value.

Example 10-2

t = 1.0 s

Other settings are same as in Example 10-1.

U_{INJ} = 2.02 x 11.0 V = 22.2 V (200% + tolerance 2% yields to multiplier 2.02)

The operation time including the inertia of the output relay should be within ±150 ms: 0.85 .. 1.15 s.

Table 18. Testing definite operation time of U_0> 59N stage

	t = 1.0 s
Secondary injection to one of I_{L1}, I_{L2} or I_{L3}	step 0 ⇒ 22.2 V
The relay should not pick up before	0.85 s
The relay should pick up before	1.15 s
actual pick up time	
ok/fail	

11. Overvoltage stage U>, ANSI 59

11.1. Trip level test

Overvoltage settings are relative the generator nominal voltage U_{GEN}.

Example 11-1

U_{GEN}	=	6300 V
U_{SET}	=	120% x U_{GEN}
U_{VTPRI}	=	12000 V
U_{VTSEC}	=	110 V
Trafo	=	Yes. There will be a unit transformer between CTs and VTs.
U_{TraBB}	=	10000 V Unit transformer's busbar side nominal voltage.
U_{TraGen}	=	6200 V Unit transformer's generator side nominal voltage.
t	=	0.10 s Set definite operation time to it's minimum to make the test easier.

The secondary voltage corresponding the nominal generator voltage is (equation 6-1)

U_{SecGen} = 6300 x 110/12000 x 10000/6200 V = 93.145 V

Injected secondary voltage that should start the protection stage

U_{INJ} = 1.20 x 93.145 V = 112 V

The actual pick up voltage should be within ±2% = 110 V .. 114 V. To find out the actual pick up level start with voltage 109 V. Then increase the injection in small steps until the relay picks up.

Table 19. Testing pick up level of U> 59 stage

Secondary injection to U_{12} or U_{23} or both inputs	112 V
The relay should not pick up before	110 V
The relay should pick up before	114 V
actual pick up level in amps	
ok/fail	

11.2. Operation delay test

11.2.1. Definite operation time

The specified operation time accuracy is achieved when the voltage before the fault is >90 % of the setting value and the fault voltage is >110% of the setting value.

Example 11-2

t = 0.50 s Definite operation time

Other settings are same as in Example 11-1.

Pre-fault voltage:

U_{INJpre} = 0.9 x 112 V = 101 V

Fault voltage:

U_{INJ} = 1.12 x 112 V = 125 V (110% + tolerance 2% yields to multiplier 1.12)

The operation time including the inertia of the output relay should be within ±30 ms: 0.470 .. 0.530 ms.

Table 20. Testing definite operation time of U> 59 stage

Secondary injection to U_{12} or U_{23} or both inputs	step 101 V ⇒ 125 V
The relay should not pick up before	470 ms
The relay should pick up before	530 ms
actual pick up time	
ok/fail	

12. Undervoltage stage U_1<, ANSI 27

The undervoltage stage is sensitive to the positive sequence voltage U_1. Positive sequence is calculated according equation 6-2. The setting is relative to the generator nominal voltage U_{GEN}.

The stage has an internal blocking feature: If the voltage has not been above setting level or the voltage is below block limit it is not considered as an undervoltage situation. This logic tries to inhibit any tripping while running the generator up. If the voltage drops fast enough below the block also tripping during running the generator down is avoided (Figure 12-1).

There is also an undercurrent blocking feature which delays the undervoltage pick up when current is less than 1% of the nominal generator current. This delay is configurable from 0.00 to 30.00 seconds.

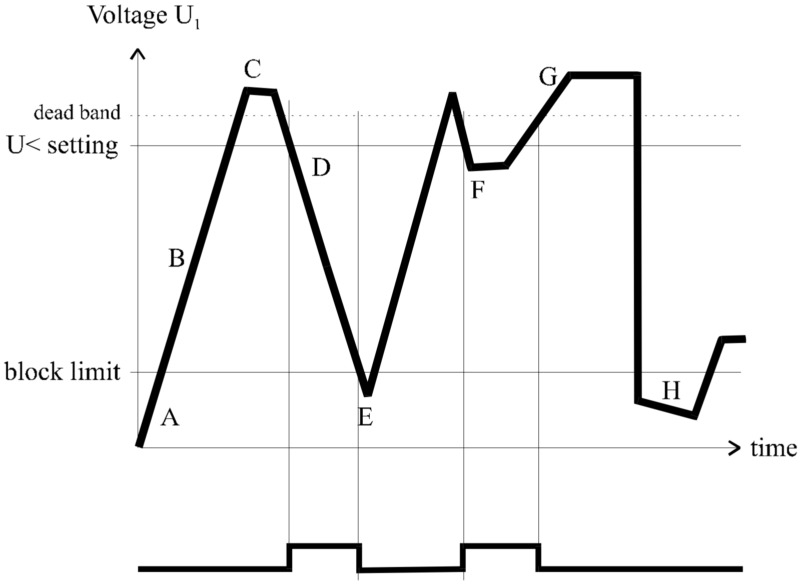

Figure 12-1 Example of the behaviour of U_1< stage.
A) Voltage is below block limit ⇒ not an undervoltage situation.
B) Voltage has not been ok since it was under block limit ⇒ not an undervoltage situation.
C) Voltage is ok ⇒ not an undervoltage situation.
D) Voltage drops below setting value ⇒ this is an UNDERVOLTAGE situation.
E) Voltage drops below block limit ⇒ not an undervoltage situation.
F) Voltage drops below setting value ⇒ this is an UNDERVOLTAGE situation.
G) Voltage rises above setting value + dead band ⇒ not an undervoltage situation.
H) Voltage drops directly below block limit ⇒ not an undervoltage situation.

12.1. Trip level test

Example 12-1

U_{GEN}	=	13800 V
U_{SET}	=	80% x U_{GEN}
U_{VTPRI}	=	15000 V
U_{VTSEC}	=	110 V
Trafo	=	No. There will be no unit transformer between CTs and VTs.
t	=	0.10 s Set definite operation time to it's minimum to make the test easier.
I_{Delay}	=	0.00 s Set undercurrent delay to zero to make the test easier.

The secondary voltage corresponding the nominal generator voltage is (equation 6-1)

U_{SecGen} = 13800 x 110/15000 x 1/1 V = 101.20 V

When **injecting equal voltage to both inputs** the relative U_1 will be:

U_{1ABS} = $U_{INJ}/\sqrt{3}$ V (equation 6-3)

U_1 = $U_{INJ}/(\sqrt{3}\text{x}101.20)$ x $\sqrt{3}$ = $U_{INJ}/101.20$ (equation 6-4)

Thus the secondary single-phase injection voltage corresponding the nominal positive sequence voltage will be

$U_{Inj100\%}$ = 101.20 V

Note: The maximum injected voltage must not exceed 175 V.

Connect the line voltage inputs of the relay parallel. (Please note that connecting the inputs in series is incorrect for this test!)

First inject about 5 % more than the trip level.

U_{12} = U_{23} = 1.05 x 0.80 x 101.20 V = 85.0 V

Injected secondary voltage that should start the protection stage

U_{12} = U_{23} = 0.80 x 101.20 V = 81.0 V

The actual pick up voltage should be within ±3% = 83.4 V .. 78.5 V. To find out the actual pick up level start with voltage 73.6 V. Then decrease the injection in small steps until the relay picks up.

Table 21. Testing pick up level of U< 27 stage

Secondary pre-injection to U_{12} and U_{23} input	85.0 V
Secondary injection to U_{12} and U_{23} input	80.1 V
The relay should not pick up before	83.4 V
The relay should pick up before	78.5 V
actual pick up level in volts	
ok/fail	

12.2. Operation delay test

12.2.1. Definite operation time

The specified operation time accuracy is achieved when the voltage before the fault is >110 % of the setting value and the fault voltage is <90% of the setting value.

Example 12-2

t = 0.50 s Definite operation time

Other settings are same as in Example 12-1.

Pre-fault voltage:
U_{INJpre} = 1.1 x 0.80 x 101.20 V = 89.1 V
Inject this voltage to both inputs of the relay.

Fault voltage:
U_{INJ} = 0.87 x 0.80 x 101.20 V = 70.4 V (90% - tolerance 3% yields to multiplier 0.87)

The operation time including the inertia of the output relay should be within ±30 ms: 0.470 .. 0.530 ms.

Table 22. Testing definite operation time of U> 59 stage

Secondary injection to U_{12} and U_{23} input	step 89.1 V ⇒ 70.4 V
The relay should not pick up before	470 ms
The relay should pick up before	530 ms
actual pick up time	
ok/fail	

13. Thermal protection stage T>, ANSI 49

A single time constant model of the generator thermal behaviour gives the following operation time for overload (IEC 60255-8, 1990-09, appendix B, hot curve)

equation 13-1

$$t = \tau \cdot \ln \frac{I^2 - I_p^2}{I^2 - (kI_{GEN})^2}$$

τ	=	Generator time constant
I	=	Measured current. Average of I_{L1}, I_{L2} and I_{L3}.
I_P	=	Pre-load current
k	=	Allowed continuous overload. User's setting.
I_{GEN}	=	Generator nominal current
ln	=	Natural logarithm function

When I_p has been zero for a long time the modelled relative temperature evens out to 0%. Then a current step $0 \Rightarrow kI_{GEN}$ will raise the relative temperature Θ to 63% ($1-e^{-1} = 0.63212$) at time τ according equation 13-2. The temperature approaches asymptotically the trip temperature of 100% as long as the current stays at kI_{GEN}.

Cold start (I_p=0) temperature model:

equation 13-2

$$\Theta = \left(\frac{I}{kI_{GEN}}\right)^2 \cdot \left(1 - e^{-\frac{t}{\tau}}\right)$$

Θ	=	Relative temperature. $\Theta_{Ambient} = 0$, $\Theta_{TRIP} = 1$. See Figure 13-1.

Time to reach a relative temperature Θ is according the cold start temperature model

equation 13-3

$$t = \tau \ln\left(\frac{I^2}{I^2 - \Theta(kI_{GEN})^2}\right)$$

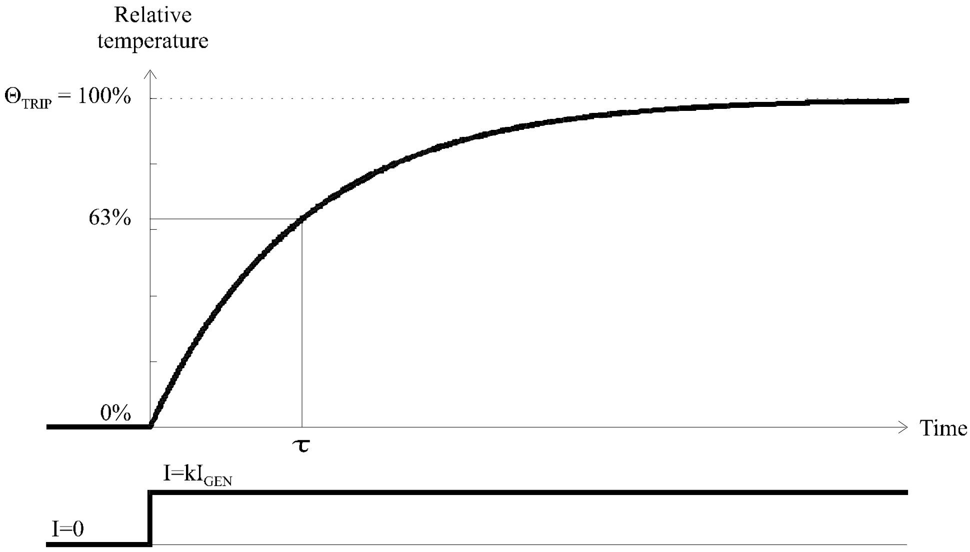

Figure 13-1 Temperature rise according the single time constant model (equation 13-2) when the current steps from zero to kI_{GEN}. Before the step the current has been zero long enough to the temperature to settle to Θ_{Amb} = 0%.

13.1. Trip level and operation delay test

Example 13-1

S_{GEN}	=	5134 kVA
U_{GEN}	=	13800 V
I_{CTPRI}	=	250 A
I_{CTSEC}	=	5 A
Trafo	=	No. There will be no unit transformer between CTs and VTs.
k	=	1.06 Allowed continuous overcurrent.
τ	=	2 min
Θ_{Alarm}	=	60% Alarm limit for temperature.

First set the injected current to zero amps and force the calculated temperature equal to 0.0%.

Let's use the injection current of I_{INJ} = 15.0 A.

When injecting only one phase current I_{INJ} the current seen by the stage is

I = $I_{INJ}/3$ = 15.0/3 A = 5.00 A

Let's calculate the operation time (equation 13-1) when the initial situation is:

Ip	=	0 (no pre-current)
Θ	=	0 (current has been zero for a long time or the temperature Θ is forced to zero)
t	=	$2 \times ln((5^2 - 0^2)/(5^2 - (1.06 \times 4.2958)^2) = 2 \times ln(5.8614) = 2 \times 1.7684 = 3.5368$ min = **03:32**

The operation time should be within ±5%: 03:22 .. 03:43.

The 60% alarm at temperature Θ_{Alarm} will be issued after (equation 13-3)

t	=	$2 \times ln(5^2/(5^2 - 0.60 \times (1.06 \times 4.2958)^2) = 2 \times ln(1.9906) = 1.3769$ min = **01:23**

The operation time should be within ±5%: 01:18 .. 01:27.

Table 23. Testing operation time of T> 49 stage

Secondary injection to I_{L1} input. Initially Θ = 0.0%	step 0 A ⇒ 15.0 A	
	Θ_{ALARM}	Θ_{TRIP}
The relay should not pick up before	01:18	03:22
The relay should pick up before	01:27	03:43
actual pick up time		
ok/fail		

14. Loss of excitation stage Q<, ANSI 40

This stage measures voltage and current and calculates a three-phase power phasor. If the tip of the complex power vector results in the forbidden area, where the magnetic coupling between stator and rotor is too weak to ensure synchronous operation, the stage will pick up. See Figure 14-1. The excitation i.e. magnetic coupling is strongest on the right where Q = +100% and there is no excitation left when Q = –100%. The nominal apparent power of the generator S_{GEN} equals 100%.
Testing this stage with single-phase test device without any phase angle control is possible. However, three phase test signals are easier to calculate.
The setting values Q_{P0} and Q_{P80} define two dots; Q_{P0} is the minimum needed reactive power at P=0 and Q_{P80} is the minimum needed reactive power at P=80%. See Figure 14-1. A line drawn through these two dots define the minimum needed magnetization for synchronous operation. If the reactive part of the measured complex power vector goes under this line (left side in the Figure 14-1) the stage picks up. If the fault situation continues the stage will give a trip signal after a adjustable delay.

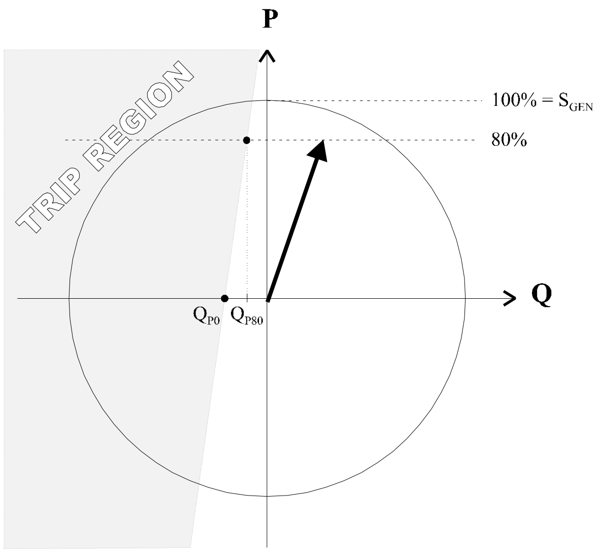

Figure 14-1 Characteristics of loss of excitation stage on a power plane. The user given values Q_{P0} and Q_{P80} define two dots; Q_{P0} is the minimum needed reactive power at P=0 and Q_{P80} is the minimum needed reactive power at P=80 %. A line drawn through these two dots define the trip area. Whenever the tip of the power vector lands on the trip area the stage picks up. The phasor in this picture is ok; normal inductive load i.e. current is lagging the voltage.

The dynamic trip line is a function of active power P
equation 14-1

$$Q_{TRIP}(P) = \frac{Q_{P80} - Q_{P0}}{P_2} P + Q_{P0}\,, \qquad \text{where}$$

P	=	Real component of the measured complex power S.
Q_{P0}	=	Setting. The minimum needed reactive power at P=0.
Q_{P80}	=	Setting The minimum needed reactive power at P=80 % x S_{GEN}.
P_2	=	80 % x S_{GEN}.

The device is calculating the complex power S using Aron's method:
equation 14-2

$$\underline{S} = \underline{U}_{12}\underline{I}^*_{L1} - \underline{U}_{23}\underline{I}^*_{L3}\,, \qquad \text{where}$$

$\underline{U}_{12}$	=	Measured line voltage L1-L2 phasor.
$\underline{I}^*_{L1}$	=	Complex conjugate[2] of the measured phase L1 current phasor.
$\underline{U}_{23}$	=	Measured line voltage L2-L3 phasor.
$\underline{I}^*_{L3}$	=	Complex conjugate of the measured phase L3 current phasor.

If there will be a unit transformer between VTs and CTs the relay configuration includes the voltage ratio and connection group of the unit transformer. The connection group will affect the lead/lag angle. E.g. connection group +30° will cause the relay to rotate the measured current phasor by –30° to compensate the transformer effect before the calculation of power.

The relative active power P is the real part of S divided by nominal apparent power (equation 5-1)
equation 14-3

$$P = \frac{real(\underline{S})}{\sqrt{3}\cdot U_{GEN} I_{GEN}} \cdot 100\%$$

[2] Just change the sign of the imaginary part of a complex number to get its conjugate. $(a+jb)^* = a-jb$

The relative reactive power Q is the imaginary part of $\underline{S}$ divided by nominal apparent power (equation 5-1)

equation 14-4

$$Q = \frac{imag(\underline{S})}{\sqrt{3} \cdot U_{GEN} I_{GEN}} \cdot 100\%$$

14.1. Single phase testing without adjustable phase angle

The VAMP 210 device is normally wired to line-to-line voltages and phase currents. The three-phase power is calculated according Aron's method (equation 14-2). Three phase voltage and current with equal phase means that phase current is leading phase voltage by 30°.

Three phase example

Let' substitute a symmetric three phase resistive phasor set into equation 14-2.

$\underline{U}_{12} = 1\angle 0°$, $\underline{I}_{L1} = 1\angle -30°$ and $\underline{U}_{23} = 1\angle -120°$ and $\underline{I}_{L3} = 1\angle -270°$.

$\underline{S} = 1\angle 0° \text{ x } 1\angle +30° - 1\angle -120° \text{ x } 1\angle +270° =$
$1\angle +30° - 1\angle +150°$

According equation 14-3 and equation 14-4 we then have for this three-phase injection case

P	=	$(\sqrt{3}/2 + \sqrt{3}/2)/\sqrt{3} = 1$
Q	=	$(1/2 - 1/2)/\sqrt{3} = 0$

Single-phase example

In case we are injecting only one test voltage and only one test current with equal phase angle we have $\underline{U}_{12} = 1\angle 0°$, $\underline{I}_{L1} = 1\angle 0°$ and $\underline{U}_{23} = 0$.

equation 14-2 will give

$\underline{S} = 1\angle 0° \text{ x } 1\angle 0° - 0 \text{ x } 0 = 1.$

According equation 14-3 and equation 14-4 we then have for this single-phase injection case

P	=	$1/\sqrt{3}$
Q	=	0

In other words the power will be pure positive active power. This can be also seen from Figure 14.1-1. Testing of this stage seems to be impossible using single-phase injection with fixed phase angles. However, by manipulating the connection group of the block transformer we can adjust the phase angle and get the device to see reactive power although the injected power is pure active power.

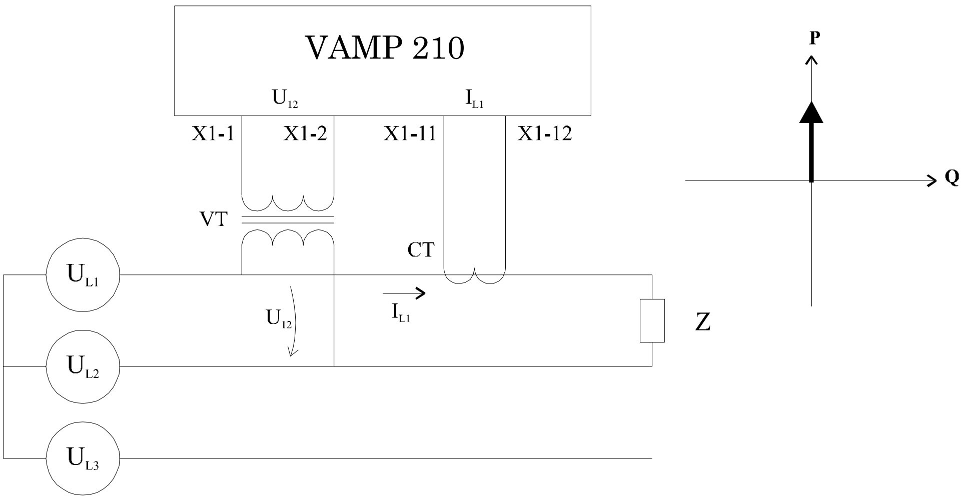

Figure 14.1-1 Single phase testing. If line voltage U_{12} and phase current I_{L1} have no phase difference this means a resistive load (Z==R) and also the corresponding power will be pure resistive. This differs from a three-phase case where resistive load causes the phase current to lag line voltage by 30°.

14.2. Three phase testing with adjustable phase angle

The VAMP 210 device is normally wired to line-to-line voltages and phase currents. The three-phase power is calculated according Aron's method (equation 14-2). Three phase voltage and current with equal phase means that phase current is leading phase voltage by 30°.

Three phase example
Let' substitute a symmetric three phase resistive phasor set into equation 14-2.
$\underline{U}_{12} = 1\angle 0°$, $\underline{I}_{L1} = 1\angle -30°$ and $\underline{U}_{23} = 1\angle -120°$ and $\underline{I}_{L3} = 1\angle -270°$.

$$\underline{S} = 1\angle 0° \times 1\angle +30° - 1\angle -120° \times 1\angle +270° = 1\angle +30° - 1\angle +150°$$

According equation 14-3 and equation 14-4 we then have for this three-phase injection case

P	=	$(\sqrt{3}/2 + \sqrt{3}/2)/\sqrt{3} = 1$
Q	=	$(1/2 - 1/2)/\sqrt{3} = 0$

The trip current will be

equation 14-5

$$I = \frac{-Q_{P0}/100}{U\left(\sin(\varphi + 30°) + \frac{Q_{P80} - Q_{P0}}{80}\cos(\varphi + 30°)\right)}, \qquad \text{where}$$

I	=	Relative trip current. 1.00 = I_{GEN}
φ	=	Phase angle of phase current
Q_{P0}	=	Minimum allowed reactive power at P = 0% in per cent.
Q_{P80}	=	Minimum allowed reactive power at P = 80% in per cent.
U	=	Relative line voltage. 1.00 = U_{GEN}

The tolerance for current will be more than the tolerance for Q:

equation 14-6

$$\Delta I = \frac{\Delta Q}{\sin(\varphi - 30°)}$$

14.3. Trip level test

Example 14-1

Three phase testing. No unit transformer is configured. $Q_{P0} = Q_{P80}$. Phase angle of the injected current is –10° = +350°.

S_{GEN}	=	8813 kVA
U_{GEN}	=	13800 V
I_{CTPRI}	=	400 A
I_{CTSEC}	=	5 A
U_{VTPRI}	=	13800 V
U_{VTSEC}	=	110 V
Q_{P0}	=	–30 % Minimum allowed reactive power at P = 0%.
Q_{P80}	=	–30 % Minimum allowed reactive power at P = 80%.
t	=	0.10 s Set definite operation time to it's minimum to make the test easier.
Trafo	=	No. There will be no unit transformer between CTs and VTs.

Nominal generator current is according equation 5-1

I_{GEN} = 8813000/(√3 x 13800) A = 368.71 A

Nominal generator current on secondary side according equation 5-2

I_{GenSec} = 368.71 x 5/400 A = 4.6089 A

Nominal generator voltage at secondary side is according equation 6-1

U_{GenSec} = 13800 x 110/13800 x 1/1 V = 110.000 V

Inject the nominal secondary generator line voltage into inputs U_{12} and U_{23}.

U_{12} = 110 V ∠0°

U_{23} = 110 V ∠+240°

The relative trip current will be according equation 14-5

I = – (–30)/100/(1.00 x sin(–10° + 30°) + ((–30) – (–30)) x cos(–10° + 30°)) = 0.3/sin(20°) = 0.87714

By multiplying the relative value by the nominal secondary current I_{GenSec} we get

I_{INJ} = 0.87714 x 4.6089 A = 4.0426 A

The Q< stage should thus start at currents

I_{L1} = 4.04 A ∠+350°

I_{L2} = 4.04 A ∠+230°

I_{L3} = 4.04 A ∠+110°

The tolerance is according equation 14-6

ΔI = ΔQ/sin(–10° + 30°) = 3/0.34202 % = 8.8 %

The actual pick up current should be within ±8.8% = 3.69 .. 4.39 A.

Table 24. Testing trip level of Q< 40 stage

Secondary fixed voltage injection to U_{12} and U_{23} inputs	amplitude	phase
	110 V 110 V	0° +240°
Secondary current injection to I_{L1}, I_{L2} and I_{L3}, inputs	amplitude	phase
	4.04 A 4.04 A 4.04 A	+350° +230° +110°
The relay should not pick up before	3.69 A	
The relay should pick up before	4.39 A	
actual pick up level in amperes		
ok/fail		

15. Reverse power stage P<, ANSI 32

This stage measures voltage and current and calculates active power P. If the active power goes under the setting value the stage will pick up. See Figure 15-1.

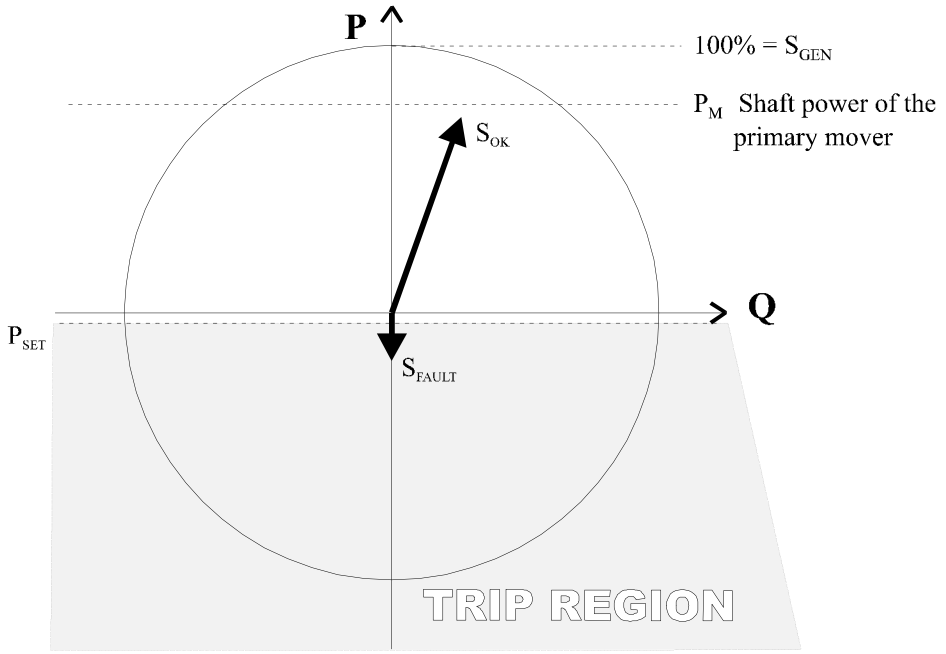

Figure 15-1 Characteristics of reverse power stage on a power plane. The vector S_{OK} will not cause a trip but shows a normal situation: The system is exporting power to a slightly inductive load. The vector S_{FAULT} is in the shaded area and will cause pick up and if the fault remains long enough the stage will trip.

The fault vector S_{FAULT} in Figure 15-1 is possible with single-phase secondary injection without phase angle control if the voltage polarity is reversed. See Figure 14.1-1.

The setting value P_{SET} is given as per cent of the shaft power of the prime mover P_M.

The tolerance for P_{SET} is ±3 % or 0.5 % of rated power value. The secondary rated power is:

equation 15-1

$$S_{N\sec} = \sqrt{3} \cdot I_{CTSEC} \cdot U_{VTSEC}$$

15.1. Trip level test

Example 15-1

See Figure 15-1.

S_{GEN}	=	5134 kVA
U_{GEN}	=	13800 V
P_M	=	4000 kW
I_{CTPRI}	=	250 A
I_{CTSEC}	=	5 A
U_{VTPRI}	=	15000 V
U_{VTSEC}	=	100 V
Trafo	=	No. There will be no unit transformer between CTs and VTs.
P_{SET}	=	–4% Minimum allowed reverse active power.
t	=	0.3 s Set definite operation time to it's minimum to make the test easier.

Nominal generator current is according equation 5-1

I_{GEN} = $5134000/(\sqrt{3} \times 13800)$ A = 214.79 A

Nominal generator current on secondary side according equation 5-2

I_{GenSec} = 214.79 x 5/250 A = 4.2958 A

Secondary current corresponding the nominal shaft power

I_{PMSec} = $P_M/S_{GEN} \times I_{GenSec}$ = 4000/5134 x 4.2958 A = 3.3469 A

Nominal generator voltage at secondary side is according equation 6-1

U_{GenSec} = 13800 x 100/15000 x 1/1 V = 92.000 V

Inject the nominal secondary generator voltage in to input U_{12}.

U_{INJ} = 92.0 V $\angle 180°$

Swap the wires to get the 180° phase angle.

We substitute $\underline{U}_{12} = 1.00\angle 180°$, $\underline{U}_{23} = 0$, and $\underline{I}_{L1} = (I\angle 0°)^*$ and $\underline{I}_{L3} = 0$ into equation 14-2

$\underline{S}$ = $1.00\angle 180° \times (I\angle 0°)^* = -I$

i.e.

real($\underline{S}$) = –I => P = –I

Next we substitute real($\underline{S}$) = –I into equation 14-3 and solve trip current

I_{INJ} = $-P_{SET}$ x √3 x I_{PMSec} = 0.04 x √3 x 3.3469 A = 0.23188 A

The P< stage should start at current
I_{INJ} = **0.232 A ∠0°**

The tolerance for P is ±3% or 0.5% of rated power value

The secondary rated power S_{Nsec} is
S_{Nsec} = √3 x 5 x 100 = 866.03 VA (equation 15-1)

0.5 % of rated power value S_{Nsec} is
0.005 x 866.03 VA = 4.33 VA

The setting value in this example is
P_{SET} = 4% x P_M = 0.04 x 4000 kW = 160 kW

On secondary side this is equal to
160000 x 5/250 x100/15000 = 21.333 W

3 % of P_{SET} is
0.03 x 21.333 W = 0.640 W

4.33 being greater than 0.64 the valid tolerance for P is 0.5 % of rated secondary power S_N i.e. 4.3 W instead of 3 % of the setting value itself (0.64 W).

The power tolerance at P_{SET} is thus
4.33/21.333 x 100 % = 20.3 %

The actual pick up current should be within ±20% = 0.186 .. 0.278 A.

Table 25. Testing trip level of P< 32 stage

Secondary fixed voltage injection to U_{12} input.	amplitude	phase
	92.0 V	180°
Secondary current injection to I_{L1} input	amplitude	phase
	0.232 A	0°
The relay should not pick up before	0.186 A	
The relay should pick up before	0.278 A	
actual pick up level in amperes		
ok/fail		

15.2. Operation delay test

The specified operation time accuracy is achieved when the active power P goes suddenly under double the setting value P_{SET}.

Example 15-2

No unit transformer. Figure 15-1.

t = 1.0 s Definite operation time

Other settings are same as in Example 15-1.

Inject the nominal secondary generator voltage in to input U_{12}.

U_{INJ} = **92.0 V ∠180°**

Swap the wires to get the 180° phase angle.

According the previous example the P< stage should start at current

I_{TRIP} = 0.232 A ∠0°

We double this value to fulfil the test requirement. Let us also take into account the tolerance of 20 %

I_{INJ} = 1.20 x 2 x 0.232 = **0.557 A ∠0°**

The operation time including the inertia of the output relay should be within ±150 ms: 0.85 .. 1.15 s.

Table 26. Testing definite operation time of P< 32 stage

Secondary fixed voltage injection to U12 input.	amplitude	phase
	92.0 V	180°
Secondary current injection to IL1 input.	amplitude	phase
	step 0 A ⇒ 0.557 A	0°
The relay should not trip before	0.85 s	
The relay should trip before	1.15 s	
actual operation time		
ok/fail		

16. Overfrequency stage f>, ANSI 81H

Testing of frequency stages need a test device with adjustable frequency output.

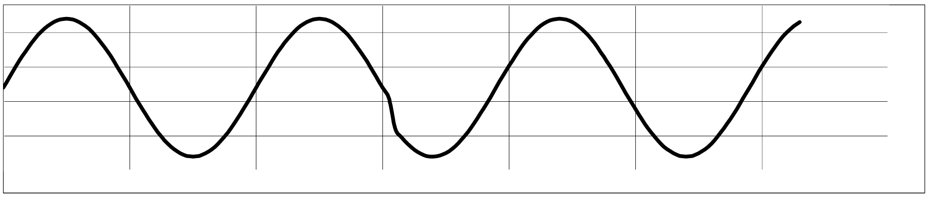

Figure 16-1 Phase shift of +20°. Greater phase spring may slow down the operation time.

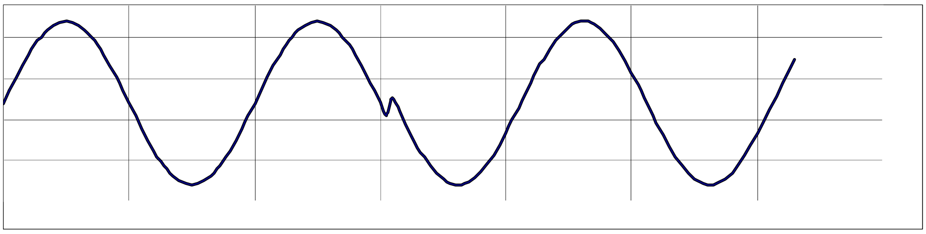

Figure 16-2 Phase shift of –20°. Greater phase spring may slow down the operation time.

16.1. Trip level test

A big frequency step is interpreted as a disturbance by the device. That is why the operation time should be tested using a smooth frequency change or a tiny frequency step. The maximum sudden frequency change should not exceed 2.5 Hz. Greater steps may prolong the operation time. Also the phase spring should not exceed ±20° (Figure 16-1and Figure 16-2). Greater phase steps may prolong the operation time.

Example 16-1

f_{SET} = 51.0 Hz Set value for overfrequency stage

t = 0.2 s Set definite operation time to it's minimum to make the test easier.

Inject voltage with frequency 50 Hz in to input U_{12} or U_{23} or both

U_{INJ} = 100 V @ 50 Hz

Slowly increase the frequency until the stage starts.

Table 27. Testing trip level of f> 81H stage

Secondary injection to U12 or U23 or both inputs	100 V
Pick up frequency	51.0 Hz
The relay should not pick up before	50.98 Hz
The relay should pick up before	51.02 Hz
actual pick up frequency	
ok/fail	

16.2. Operation delay test

A big frequency step is interpreted as a disturbance by the device. That is why the operation time should be tested using a frequency ramp or a tiny frequency step. The maximum sudden frequency change should not exceed 2.5 Hz. Greater steps may prolong the operation time. Also the phase spring should not exceed ±20° (Figure 16-1 and Figure 16-2). Greater phase steps may prolong the operation time.

Example 16-2

f_{SET} = 51.0 Hz Set value for overfrequency stage

t = 1.0 s

Limit the phase spring to less than 20° when switching to the higher frequency.

Table 28. Testing operation time of f> 81H stage

Secondary injection to U_{12} or U_{23} or both inputs	100 V
Frequency	step 50.9 Hz ⇒ 51.1 Hz
The relay should not pick up before	970 ms
The relay should pick up before	1030 ms
actual pick up time	
ok/fail	

17. Underfrequency stage f<, ANSI 81L

Testing of frequency stages need a test device with adjustable frequency output. The underfrequency stage has two internal blocking functions.

1. The frequency must first be over the setting value before the under situation is considered as underfrequency.
2. If the actual voltage U_1 is less than the adjustable limit U_{COLD} the underfrequency stage is blocked.

17.1. Trip level test

A big frequency step is interpreted as a disturbance by the device. That is why the operation time should be tested using a smooth frequency change or a tiny frequency step. The maximum sudden frequency change should not exceed 2.5 Hz. Greater steps may prolong the operation time. Also the phase spring should not exceed ±20° (Figure 16-1and Figure 16-2). Greater phase steps may prolong the operation time.

Example 17-1

f_{SET} = 49.0 Hz Set value for overfrequency stage
U_{COLD} = 20 % x Ugn Cold limit for voltage amplitude
t = 0.2 s Set definite operation time to it's minimum to make the test easier.

Inject voltage with frequency 50 Hz in to input U_{12} or U_{23} or both
U_{INJ} = 100 V @ 50 Hz

Slowly decrease the frequency until the stage starts.

Table 29. Testing trip level of f< 81L stage

Secondary injection to U_{12} or U_{23} or both inputs	100 V
Pick up frequency	49.0 Hz
The relay should not pick up before	49.02 Hz
The relay should pick up before	48.98 Hz
actual pick up frequency	
ok/fail	

17.2. Operation delay test

A big frequency step is interpreted as a disturbance by the device. That is why the operation time should be tested using a frequency ramp or a tiny frequency step. The maximum sudden frequency change should not exceed 2.5 Hz. Greater steps may prolong the operation time. Also the phase spring should not exceed ±20° (Figure 16-1and Figure 16-2). Greater phase steps may prolong the operation time.

Example 17-2

f_{SET} = 49.0 Hz Set value for underfrequency stage

U_{COLD} = 20 % x Ugn Cold limit for voltage amplitude

t = 1.0 s

Limit the phase spring to less than 20° when switching to the lower frequency. Make sure that no current is injected.

Table 30. Testing operation time of f< 81L stage

Secondary injection to U_{12} or U_{23} or both inputs	100 V
Frequency	step 49.1 Hz ⇒ 48.9 Hz
The relay should not pick up before	0.97 s
The relay should pick up before	1.03 s
actual pick up time	
ok/fail	

18. Symbols

List of scaling and setting variables and their labels. The *variable* names are used in formulae to calculate injection values and corresponding setting values. *Labels* are the corresponding names used by the local user interface of the relay. Those ones with a **bold** label are configurable by the user.

Generator values

Variable	*Label*	*Explanation*
S_{GEN}	**Sgn**	Nominal power of the generator
U_{GEN}	**Ugn**	Nominal voltage of the generator
I_{GEN}	Ign	Nominal current of the generator
P_{SHAFT}	**Pm**	Nominal shaft power of the prime mover

Phase current measurement

Variable	*Label*	*Explanation*
I_{CTPRI}	**Inom**	Nominal CT primary value (I_{L1}, I_{L2}, I_{L3})
I_{CTSEC}	**Isec**	Nominal CT secondary value
I_{INPUT}	Iinput	Nominal input current of the relay

Voltage measurement

Variable	*Label*	*Explanation*
U_{VTPRI}	**Unom**	Nominal VT primary value
U_{VTSEC}	**Usec**	Nominal VT secondary value
U_{VToSEC}	**UoSec**	Nominal VT secondary residual voltage during rigid earth fault
U_{TraBB}	**UnBB**	Nominal voltage of unit transformer, busbar side
U_{TraGen}	**UnGS**	Nominal voltage of unit transformer, generator side

Residual current input 1

Variable	*Label*	*Explanation*
$I_{CTo1PRI}$	**Io1n**	Nominal primary value of the CT connected to residual current input 1
$I_{CTo1SEC}$	**Io1sec**	Nominal secondary value of the CT connected to residual current input 1
$I_{01INPUT}$	**Io1inp**	Nominal residual current of the relay input I_{01}

Residual current input 2

Variable	*Label*	*Explanation*
$I_{CTo2PRI}$	**Io2n**	Nominal primary value of the CT connected to residual current input 2
$I_{CTo2SEC}$	**Io2sec**	Nominal secondary value of the CT connected to residual current input 2
$I_{02INPUT}$	**Io2inp**	Nominal residual current of the relay input I_{02}

Overcurrent protection

Variable	*Label*	*Explanation*
I_{SET}	**I>**(3	User given per unit (e.g. 1.2 x I_{GEN}) pick-up value of overcurrent stage
t	**t>**	Operation delay
U_1	U1	Positive sequence voltage
I'_{SET}		Actual pick-up value of the 51V restrained/restricted overcurrent stage
x_1	X1	Relative start value of the controlling positive sequence voltage U_1.
x_2	X2	Relative stop value of the controlling positive sequence voltage U_1.
y_1	Y1	Relative start multiplier for the setting value I_{SET}.
y_2	Y2	Relative stop multiplier for the setting value I_{SET}.

Unbalance current protection

Variable	*Label*	*Explanation*
I_2	I2	Negative sequence current

Undervoltage protection

Variable	*Label*	*Explanation*
I_{Block}	I<Blk	Undercurrent block delay. If current is less than 1% of I_{GEN} this parameter defines an extra pick up delay for the undervoltage stage

Stator overload protection (thermal image)

Variable	*Label*	*Explanation*
k	T>	Continuous allowed overcurrent factor.
τ	tau	Generator time constant

(3 The actual label depends of the particular protection stage. I> is used by the first overcurrent stage.

Loss of excitation protection

Variable	*Label*	*Explanation*
Q_1	`Q@P0%`	Minimum allowed reactive power at P = 0%
Q_2	`Q@P80%`	Minimum allowed reactive power at P = 80%
C_{GRP}	`ConGrp`	Unit transformers connection phase shift from primary to secondary.

Reverse power protection

Variable	*Label*	*Explanation*
P_{SET}	`P<`	Maximum allowed reverse active power
S_N	`CTxVT`	Nominal apparent power
S_{Nsec}		Nominal secondary apparent power

Underfrequency protection

Variable	*Label*	*Explanation*
U_{COLD}	`NoCmp`	Under this voltage the underfrequency stage is blocked

19. Reference information

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