Transformer Overcurrent Protection Coordination

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Introduction

IEEE Guide for Liquid-Immersed Transformer Through-fault-current Duration C57.109-1993 (R2008) defines the transformer damage curve that is used for transformer overcurrent protection. This method is further discussed and provided with examples in Appendix A of IEEE Guide for Protecting Power Transformers C37.91–2008. This paper presents a tutorial with information drawn from these two guides highlighting the damage curve development and its use for different transformer MVA capacities. Also discussed are the effect of different winding configurations on coordination.

Transformer Damage Curve

IEEE Guide C57.109-1993 (R2008) considers both thermal and mechanical effects for external transformer through faults. The transformer's capability to withstand these effects is shown in Figure 1. The thermal capability is a long used curve developed empirically and originally published as a table in ANSI C57.92-1962, American National Standard Guide for Loading Oil-Immersed Distribution and Power Transformers and republished in C57.109-1993 (R2003). This data is shown in Table 2 for Times Rated Current values up to 25. It was originally developed and used for transformer protection without consideration for the accumulated effect of mechanical stresses during short circuits. Over the past 50 years or more the mechanical effect of short-circuits have been more accurately defined based on application. Today, the capability curve is modified in the short time, high current region showing the transformer's mechanical limit more accurately considering the accumulated effect of through-faults. This modification is shown in Figure 1 and identified by Mechanical Capability. This curve, however, is not uniform for all transformer sizes. In some cases the Thermal Capability alone is sufficient to address thermal and mechanical requirements and in other cases a Mechanical Capability limitation must be implemented. Therefore, transformer applications are divided into four categories based on their kVA and through-fault exposure. These categories are shown in Table 1. The capability curves for each category are shown in Appendix A and are discussed below.

Understanding I^2t

I^2t (I = amps, t = time) A^2s is proportional to the increase of thermal energy (heat – Ws) in a conductor with a constant current over time. In transformers an I^2t value is defined to show the thermal limits of their windings before damage occurs. The values I (times rated winding current) and t from C57.109 are reproduced in Table 2 with an additional column showing the calculated I^2t value. Also, two additional rows for I equal to 35 and 40 are added. The data is based on symmetrical fault current in the winding. As can be observed each point for I between 2 and 25 has a different I^2t value producing the "Thermal Capability" curve of Figure 1.

It should be noted that this curve represents the thermal limit for short circuits. It is a defined curve and does not include the effect of the transformer's operating environment. Thermal limits for overloads, however, are addressed by transformer oil and/or winding temperature measurement that need to be considered where the current is less than 3.5 times the transformer's winding rated current. Refer to the IEEE Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators C57.91-2011 for more information.

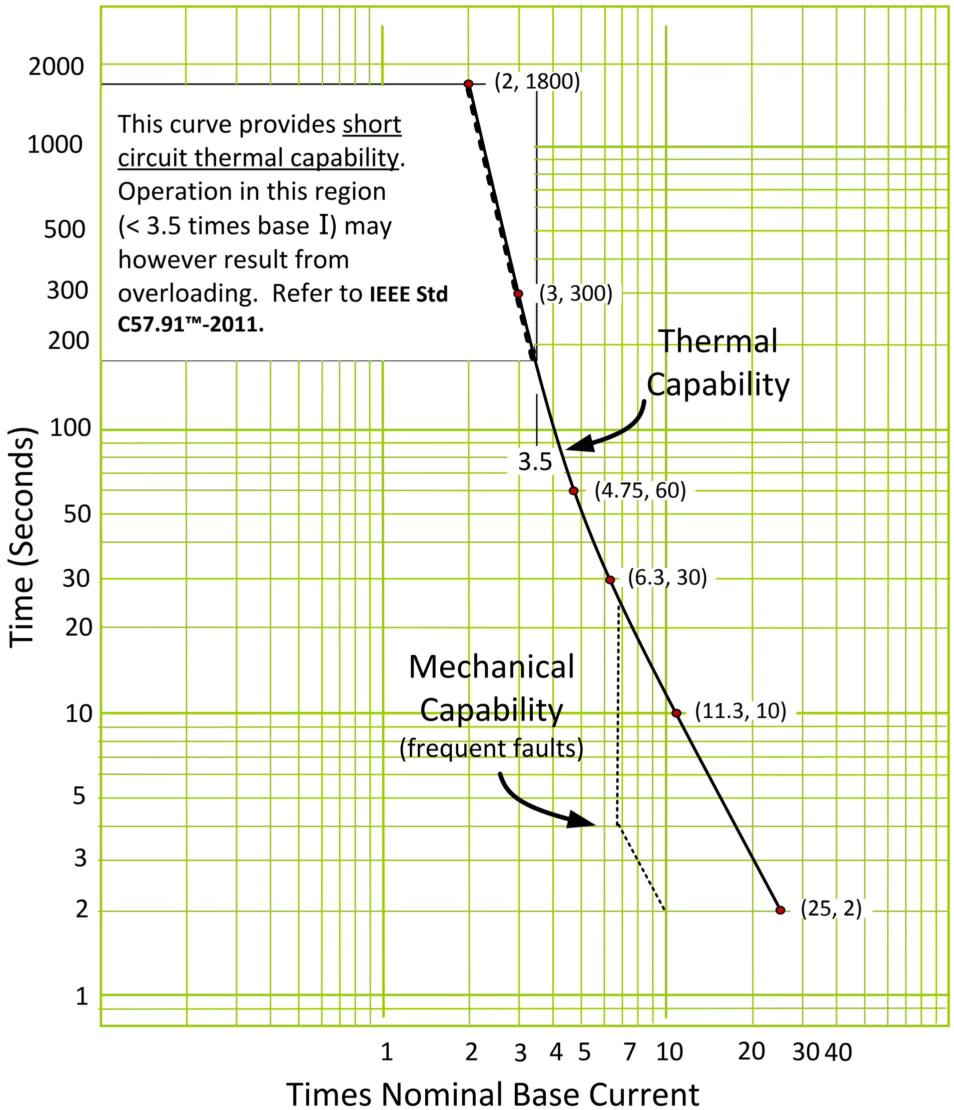


Figure 1. Example Transformer Damage Curve

Table 1. Transformer Categories		
Category	Single phase (Minimum nameplate KVA)	Three phase (Minimum nameplate KVA)
I	5 - 500	15 - 500
II	501 - 1667	501 - 5000
III	1668 – 10,000	5001 – 30,000
IV	Above 10,000	Above 30,000

Table 2. Short time thermal load (and short circuit) capability		
Times rated current (I)	Time in seconds (t)	I^2t
2.0	1800	7200
3.0	300	2700
4.75	60	1354
6.3	30	1190
11.3	10	1277
25	2	1250
35*	1.02	1250
40*	0.78	1250
*Extended curve for Category I transformers		

Rated Winding Current

The referenced transformer standards use the terms rated current and nominal base current without clear definition. As protection engineers we consider the rated or base current as the transformer' rated line current. This permits computation of current on all sides of a transformer for a through fault (e.g. from HV to LV) in per unit. The terms rated and base current in this paper and referenced standards, however, refer to the winding current, which is different than the line current in the case of delta connected windings. This difference has an impact that affects proper coordination with the damage curve and will be discussed in a later section. To reiterate, in this paper the terms rated current and nominal base current refer to the rated winding current, which is the current in the winding when the transformer is operating at rated KVA and rated voltage.

Determining the Damage Curve

The transformer's through fault withstand capability curve can generally be provided by the manufacturer if requested by specification. If not available it can be defined completely or in part, depending on the category, by the thermal capability characteristic of Figure 1. The mechanical capability characteristic is introduced to account for the loss of the winding's mechanical integrity that occurs with the exposure to frequent through-faults, their duration and magnitude. Table 3 at the end of this section provides a guide for selecting the appropriate damage curve.

Fault Frequency

An attempt is made to define the transformer's fault exposure as frequent or infrequent.

- Frequent fault exposure is where there are a defined number of through-faults in the transformer's lifetime above a defined current magnitude, which is expressed as percent of the transformer's maximum through-fault current (I_{Max}).
- Infrequent fault exposure is where there are fewer transformer through-faults in the transformer's lifetime than the defined number and magnitude given above for the same transformer category.

The defined number of faults and their magnitudes for fault frequency are defined differently for Categories II, III and IV and summarized in Table 3.

Application

The protection normally provided that coordinates with the damage curve is typically an inverse time-overcurrent device such as a fuse or relay. It may be the primary (the only) protection used to clear the through-fault, or it may be the backup protection to another primary device or system that detects and clears the fault high-speed. High-speed fault clearing is normally 100 - 200 ms., which is typically less than one tenth of the clearing time when using a time-overcurrent device for protection of the thermal curve of Figure 1. Therefore, the accumulated mechanical stress on the winding is proportionally less and the mechanical characteristic may not be required. One has to also consider the potential failure of the protection system to clear all faults high-speed. Such occurrences must be infrequent. Therefore, the capability curve used for protection coordination also depends on the protection being applied – primary (the only protection) or backup to high-speed.

Maximum Through-fault Current, I_{Max}

The maximum transformer symmetrical through fault current (I_{Max}) used to define the mechanical capability and is limited by the positive sequence transformer or the sum of the positive sequence transformer and source impedances. It is the winding's maximum current withstand capability at 2 seconds. Although not specifically stated in the referenced standards the calculation of I_{Max} is based on a simple three-phase through-fault calculation where the impedance values are in per unit of the transformer base impedance. Per unit voltage is assumed to be 1. Only the transformer impedance, Z_T, is used to compute I_{Max} for Category II transformers and the transformer, Z_T, plus source, Z_S, impedance is used for Category III and IV transformers.

Category II $$I_{Max} = 1/Z_T \tag{1}$$

Category III and IV $$I_{Max} = 1/(Z_T + Z_S) \tag{2}$$

Category III and IV transformers are larger MVA transformers with higher through-fault currents that produce considerably more forces acting upon the windings and thus require using the equivalent source impedance at the transformers location as part of the transformer design criteria. The source impedance should be specified to the transformer manufacturer. If not the manufacturer will use the appropriate information from Table 4 to compute a source impedance. Table 4 is copied from IEEE Guide C57.109-1993 (R2008) except the % impedance at 100 MVA is derived to show relative values of source impedance.

Table 3. Capability curve application requirements				
Category	Fault Frequency	Application	Capability Curve	I_{Max} pu @ 2 seconds
I	N/A	N/A	Thermal	N/A
II	Frequent *>10 faults ≥ 70% I_{Max} in Lifetime*	Primary	Thermal and Mechanical	*$1/Z_T$*
		Backup	Thermal	N/A
	Infrequent *≤10 faults, etc.*	Either	Thermal	N/A
III	Frequent *> 5 faults ≥ 50% I_{Max} in Lifetime*	Primary	Thermal and Mechanical	*$1/(Z_T+Z_S)$*
		Backup	Thermal	N/A
	Infrequent *≤ 5 faults, etc.*	Either	Thermal	N/A
IV	Frequent or Infrequent	Either	Thermal and Mechanical	*$1/(Z_T+Z_S)$*
N/A – Not Applicable, Z_T – Positive sequence transformer impedance, Z_S – Positive sequence source impedance used by manufacturer for design				

Table 4. System short circuit apparent power to compute source impedance			
Maximum System Voltage (kV)	System Fault Capacity		% Impedance at 100 MVA
	kA rms	MVA	
Below 48.3	--	4300	2.33
48.3	54	4300	2.33
72.5	82	9800	1.02
121.0	126	25100	0.398
145.0	160	38200	0.262
169.0	100	27900	0.358
242.0	126	50200	0.199
362.0	84	50200	0.199
550.0	80	69300	0.144
800.0	80	97000	0.103

Category I Transformers

Category I transformers are limited to 500 kVA (or kVA parts in the case of autotransformers) and are generally applied on distribution systems. They require appropriate primary fusing for clearing internal faults where the transformer has failed, and severe secondary faults, which are considered infrequent. Most secondary faults, however, are cleared by other secondary protection devices such as fuses and molded case breakers and do not impose severe mechanical stress on the transformer. Therefore, the additional mechanical limitations of the curve are not required.

The Category I curve is also extended with a constant 1250 A^2s thermal capability (the value calculated in Table 2 for 25 times rated I for 2 seconds) to include transformers with impedances down to 2.5%. This impedance will permit a through-fault current up to 40 times rated current. Refer to the Category I curve of Appendix A.

Category II Transformers

Category II transformers are equal to or smaller than 1667 kVA single phase and 5000 kVA three phase and are applied in accordance with Equation 1 and Table 3 depending on the application and protection. Primary (high voltage) protection is normally time coordinated with secondary devices that are not high-speed. Therefore, more often than not the use of the mechanical characteristic is required. Consider the following example.

The 5000 kVA transformer is protected by a time overcurrent device that must trip before damage occurs to the transformer and coordinate with secondary devices. In this example we are primarily interested in defining the appropriate transformer damage curve. The maximum through-fault current is calculated in accordance with Equation 1 using only the transformer impedance and is found to be (1/0.076) 13.2 pu. It is determined that there will most likely be greater than 10 faults on the transformer secondary in regions 1, 2 and 3 that are greater than 70% of 13.2 pu – 9.24 pu. Therefore the mechanical characteristic is desired. From this we can define the two end points of the mechanical characteristic. The point at I_{Max} is by definition 13.2 pu A at 2 seconds. From these values I^2t ($13.2^2 \cdot 2$) is calculated to be 348.5 A^2s. The limiting withstand time at 70% I_{Max} (9.24 pu) is calculated with this constant I^2t value as 4.08 seconds (t = 348.5/9.24^2). The mechanical characteristic implementation is shown in Figure 3.

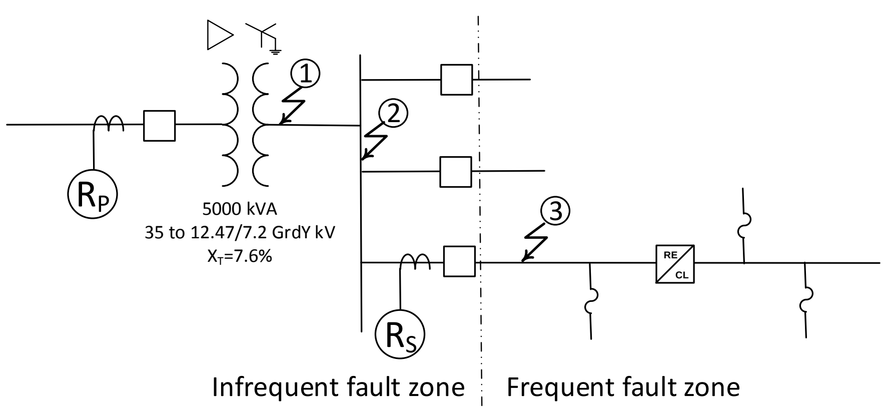


Figure 2. Category II Application

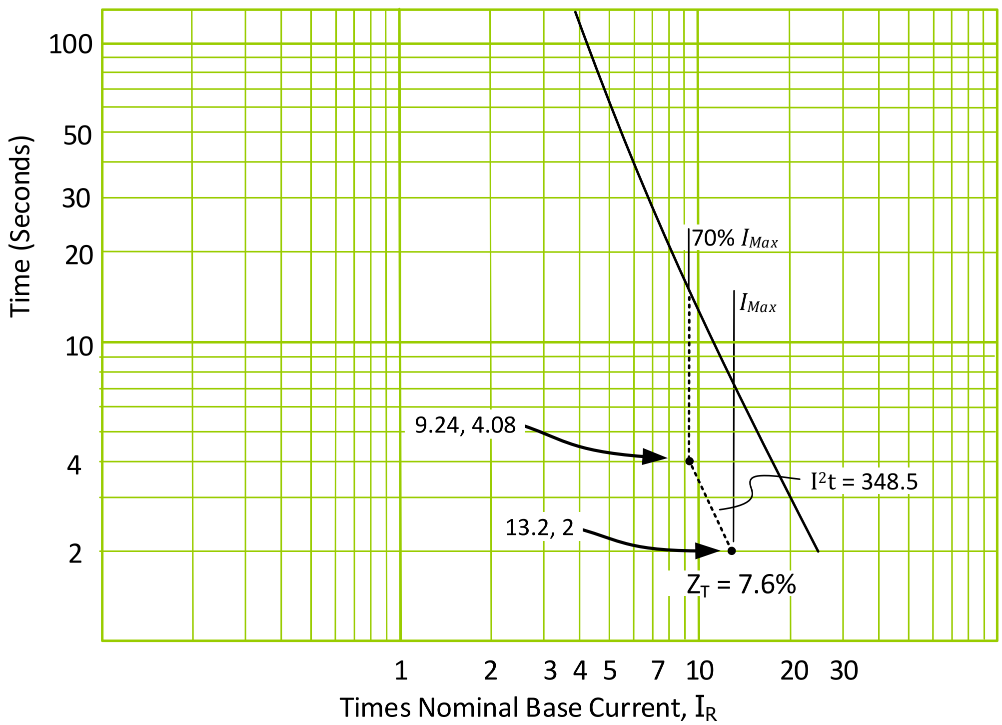


Figure 3. Category II Mechanical Characteristic Implementation

Category III Transformers

Category III transformers are equal to or smaller than 10 MVA single phase and 30 MVA three phase and are applied in accordance with Equation 2 and Table 3 depending on the application and protection. Primary (high voltage) protection is coordinated with secondary devices that may or may not be high-speed. Therefore, it is important for the protection engineer to understand the application. Consider the example of Figure 4.

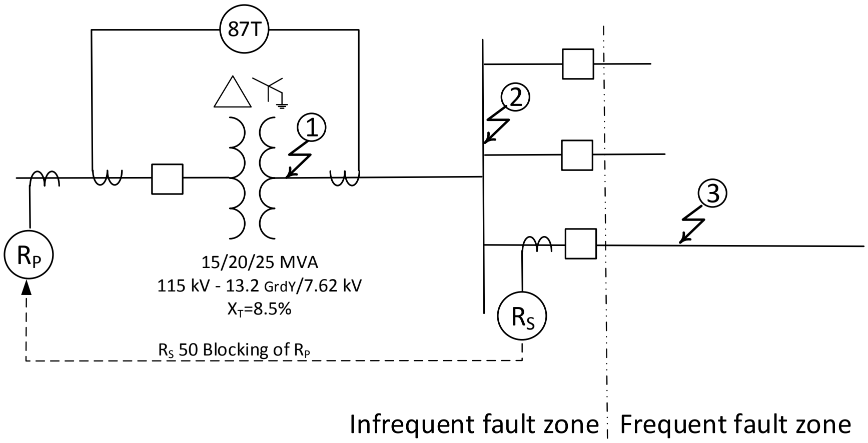


Figure 4. Category III Application

The 15 MVA transformer is protected by a time overcurrent device that must trip for through-faults before damage occurs to the transformer and coordinate with secondary devices. In this example we are primarily interested in defining the appropriate transformer damage curve. The maximum through-fault current is calculated in accordance with Equation 2 using the transformer and source impedance. The source impedance was not specified to the manufacturer at the design time, therefore the source impedance derived from Table 4 is used. From Table 4 we use the system fault capacity MVA where the maximum system voltage is 121 kV. In this case the system per unit impedance expressed on the transformer's MVA base is very small and could easily be neglected. This is probably true for most Category III applications.

$$Z_S = MVA_T/MVA_S \text{ (on Transformer base MVA)} \qquad (3)$$

$$Z_S = 15/25100 = 0.0006 \text{ pu}$$

I_{Max} is found to be (1/0.0856) 11.68 pu. Faults will be cleared high-speed in regions 1 and 2. However, region 3 faults are cleared with time overcurrent relays. Therefore the high voltage side relay, R_P, is considered primary protection for transformer through faults. It is determined that there will most likely be greater than 5 faults in the transformer's lifetime on the region 3 feeder that are greater than 50% of 11.68 pu – 5.84 pu. Therefore, the mechanical characteristic is desired. From this we can define the two end points of the mechanical characteristic. The point at I_{Max} is by definition 11.68 pu A at 2 seconds. From these values I^2t ($11.68^2 \cdot 2$) is calculated to be 272.8 A^2s. The limiting withstand time at 50% I_{Max} (5.84 pu) is calculated with this constant I^2t value as 8.0 seconds ($272.8/5.84^2$). The mechanical characteristic implementation is shown in Figure 5.

Had the region 3 feeder been protected with a high-speed impedance relay and the fault level beyond its reach was below 50% of I_{Max} then relay R_P would be considered backup and the mechanical characteristics would not be required. This would also apply to any other scheme that would provide high-speed clearing.

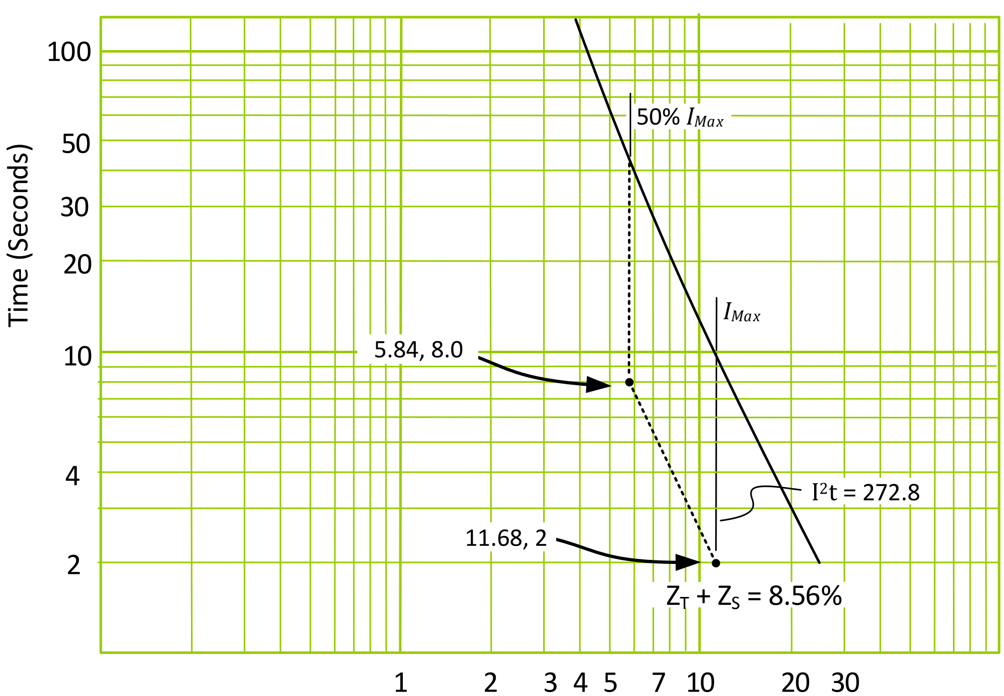


Figure 5. Category III Mechanical Characteristic Implementation

Category IV Transformers

Category IV transformers are larger than 10 MVA single phase and 30 MVA three phase. They can be quite large and subject to tremendous short circuit stress. Therefore, the mechanical characteristic limitation will always be required regardless of fault frequency and I_{Max} will always be calculated using Equation 2 that includes both transformer and source impedance. The procedure to determine the mechanical characteristic is the same as shown for Category III transformers.

Coordination

There are two coordination functions of the primary side time-overcurrent protection. These are to protect the transformer windings from damage due to extended secondary through faults and to allow tripping of secondary devices or systems designed to detect and clear the secondary faults before it trips. Coordination between primary and secondary line currents is a relatively straight forward apples-to-apples comparison process. Coordination between the primary line and winding currents depends on the transformer connection . . . wye-wye, delta-wye, etc. is not always so straight forward. Guides are available from IEEE and manufacturers that discuss coordination with the transformer damage curve presenting factors by which to shift the primary protection device operating characteristic or transformer damage curve that the authors find a bit confusing. The intent of this section is to describe the fundamentals without just presenting tables of factors for shifting curves to facilitate a better understanding.

Apples to Apples

When coordinating any two time-overcurrent curves they are most easily compared when on the same current base. This applies whether the two curves are of fuses, relays, or transformer winding capability (damage curve). In the following example two standard very inverse curves [5] will be used that have the same primary ampere pickup but different time dial settings.

When these two relays are monitoring the same primary current it is easy to view their coordination in Figure 6. For example, at 10,000 A they have a coordination margin of around 90 cycles.

Figure 7 is a simple case where a transformer has now been inserted in the circuit such that the two relays are not seeing the same primary current, but they are seeing currents that are directly proportional.

The relay on the secondary of the transformer now monitors twice the current that the relay on the primary does. In order to be able to compare "apples to apples" on our coordination plot we need to scale one of the curves to put it on the same base as the other. It does not matter which one we scale. In this example we will scale the secondary relay curve to put it on the primary current base. We do this by multiplying each current point on the secondary relay's curve by the factor (I_X/I_Y) which equates to 1/2 in this case. The left hand plot in Figure 8 shows the original coordination when the relays monitored the same current, the right hand plot shows the coordination (on I_X base) with the transformation in place.

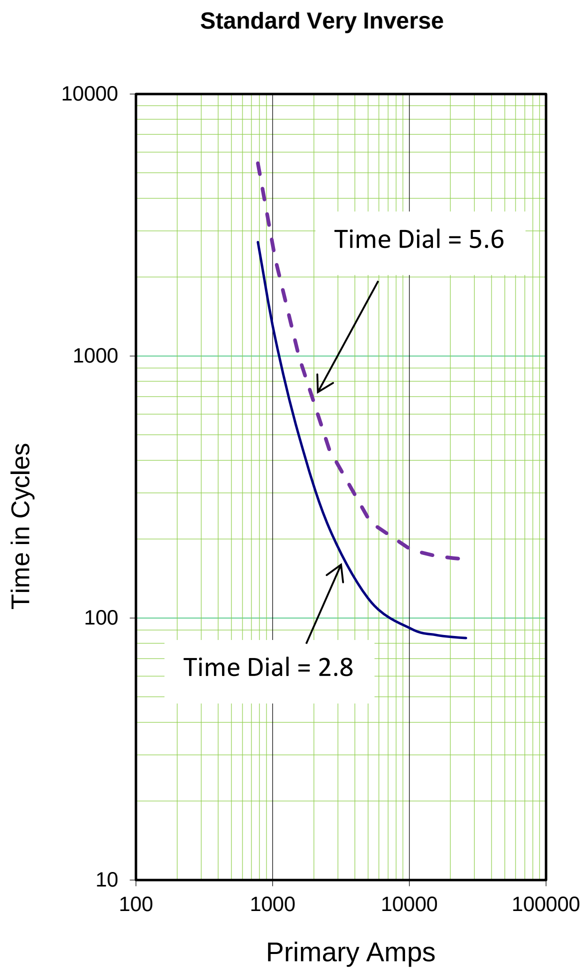


Figure 6 – Standard Very Inverse Curves

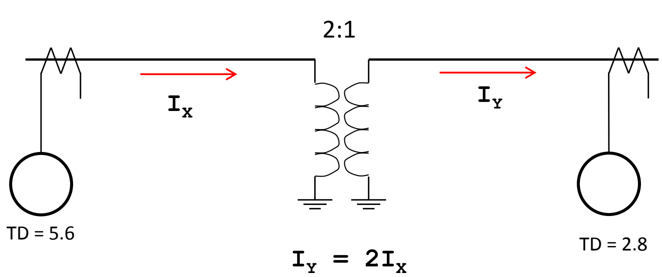
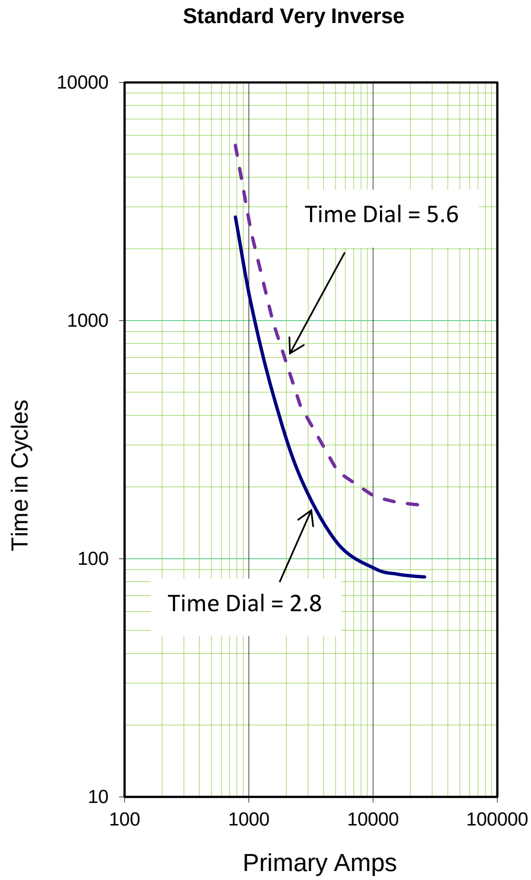


Figure 7 – Simple transformation in series circuit.



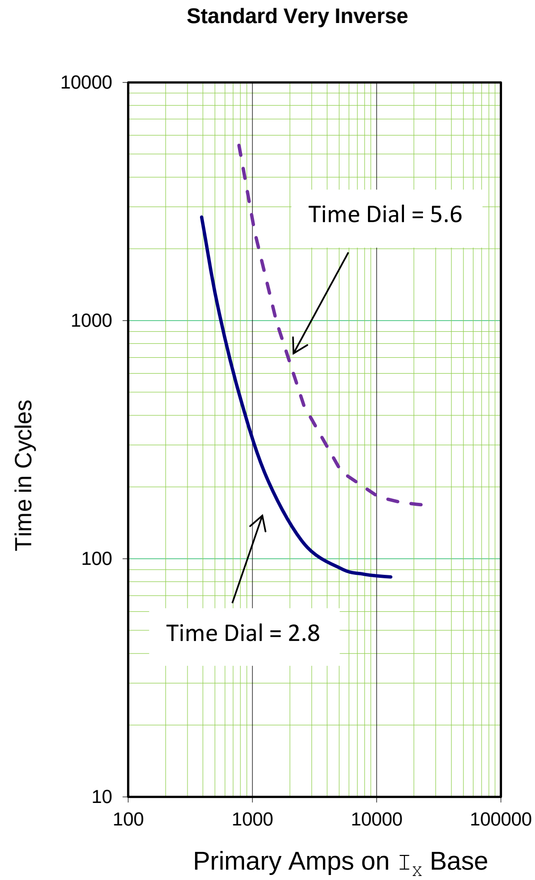


Figure 8 – Putting Curves on Same Base

The right hand plot in Figure 8 shows that the curve moved to the left. This shows us that to shift any curve and put it on another curves base we just multiply each current value on the curve by the ratio between the two currents. In this ratio the numerator is the current being converted to and the denominator is the current being converted from. The resulting coordination plot will be valid as long as the ratio between the two currents is always the same.

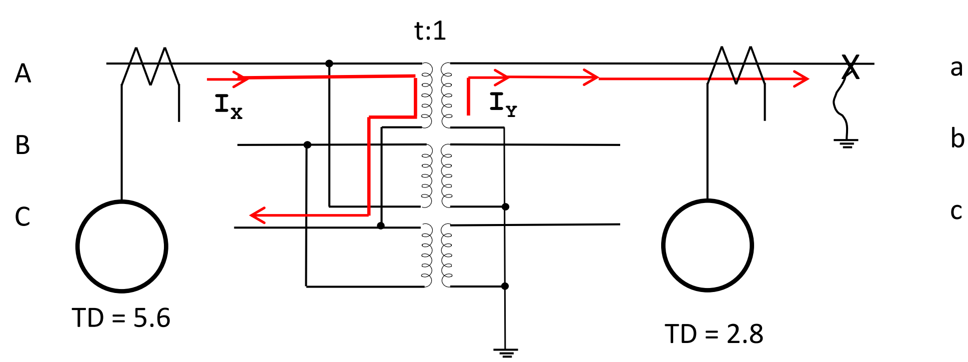


Figure 9 – Delta-wye transformer with secondary ground fault.

Figure 9 shows a delta-wye transformer bank with a phase-to-ground fault on the secondary. It can be seen from the drawing that the ratio of I_X to I_Y is 1/t where "t" is the phase winding turns ratio. So, we can shift the secondary side relay curve to the primary side relays current base by multiplying each current point by the ratio (1/t). We can just as easily shift the primary side relay curve to the secondary side base by multiplying each of its current points by (t/1) if we choose.

Figure 10 shows the same configuration but with a secondary B-C phase fault. In this case our single-phase secondary relay has been moved to the middle phase (b).

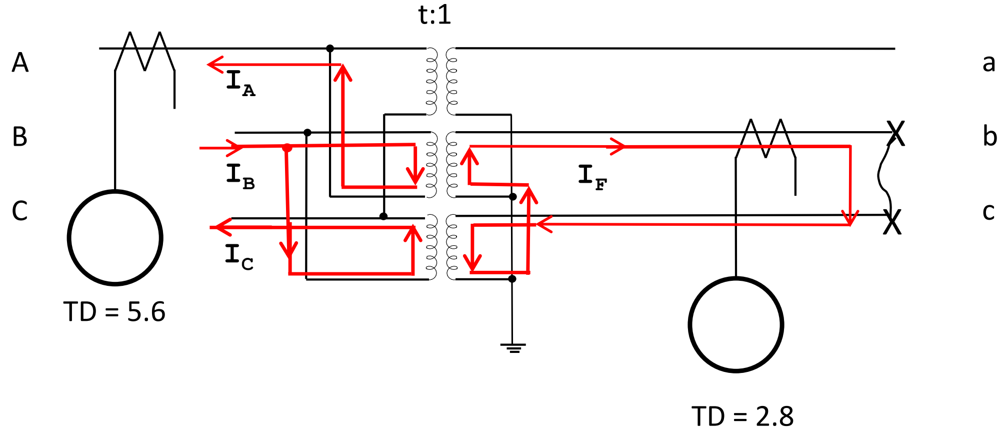


Figure 10 – Delta-wye transformer with secondary phase-phase fault.

The following equations show the relationship between each of the three primary-side phase currents to the current I_F.

$$I_A = \frac{I_F}{t}$$

$$I_B = \frac{2I_F}{t}$$

$$I_C = \frac{I_F}{t}$$

So, the ratio by which we would scale the secondary relay current points would be ($I_A/I_F = 1/t$). It is important to note that in this case, if our primary relay is moved to B-phase then the ratio would become ($I_B/I_F = 2/t$). Since it is almost always the case that primary side phase-time-overcurrent relays measure current on an individual phase basis then the closest coordination would exist between the secondary side b- or c-phase relay and the primary side B-phase relay for the fault shown in Figure 10.

Apples to Damage Curves

When checking coordination between primary side phase-time-overcurrent protection and the primary winding damage curve it is important that the two curves be on the same base. As previously stated in this paper, the damage curve as defined in IEEE C57.109 [2] is based on winding current, which is only equal to line current for wye windings. In the following examples we will show how to shift the primary winding damage curve, which is in amperes, to compare to the primary side relay for various faults. We are only referring to it as the "primary winding damage curve" to make it clear what current base will be used to create the curve.

Note that for a delta-wye bank the primary winding damage curve (in per unit on "inside the delta" base amps) is identical to the secondary winding damage curve in per unit on secondary side base amps. Note also, and this is very important, that the primary winding damage curve is converted from per unit or "Times Nominal Base Current" using the current base that is inside the delta. This differs from the primary side line current base by a factor of $1/\sqrt{3}$. Failing to recognize this is a common mistake made when dealing with transformer damage curves.

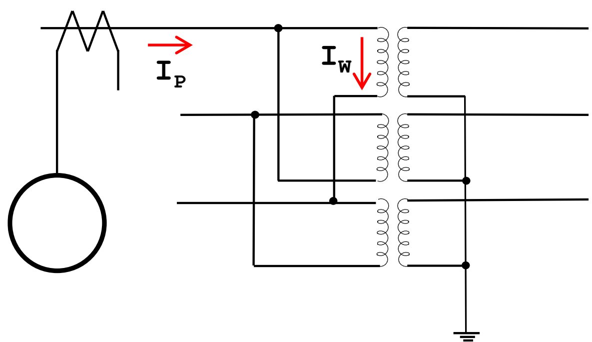


Figure 11 – Coordinating with Winding Damage Curve, Delta-wye Bank

Another common mistake is failure to recognize that <u>the ratio by which we shift the curve is not constant and depends on the type of fault</u>. This is an important point that is not always properly accommodated when checking coordination, particularly when using coordination software that doesn't automatically shift the winding damage curve based on the actual ratio of currents as described above.

It is convenient to think of the winding damage curve as a fuse located in series with the winding and shift its curve to coordinate with the device of interest (fuse or relay etc.) as we describe in preceding sections.

Low-side Three-Phase Faults

To check coordination between our primary protection and the primary winding damage curve for low-side three-phase faults we will scale the damage curve current points by the factor ($I_P/I_W = \sqrt{3}$) since we know the primary line current for this balanced condition is $\sqrt{3}$ larger than the current inside the delta. This will put both curves on the primary line current base. This will have the effect of pushing the unmodified winding damage curve to the right. The left-hand plot in Figure 12 shows the unmodified winding damage curve and also the shifted winding damage curve (shifted by $\sqrt{3}$ to the right). The right-hand plot shows the winding damage curve and the relay curve both plotted on the same base (line amps).

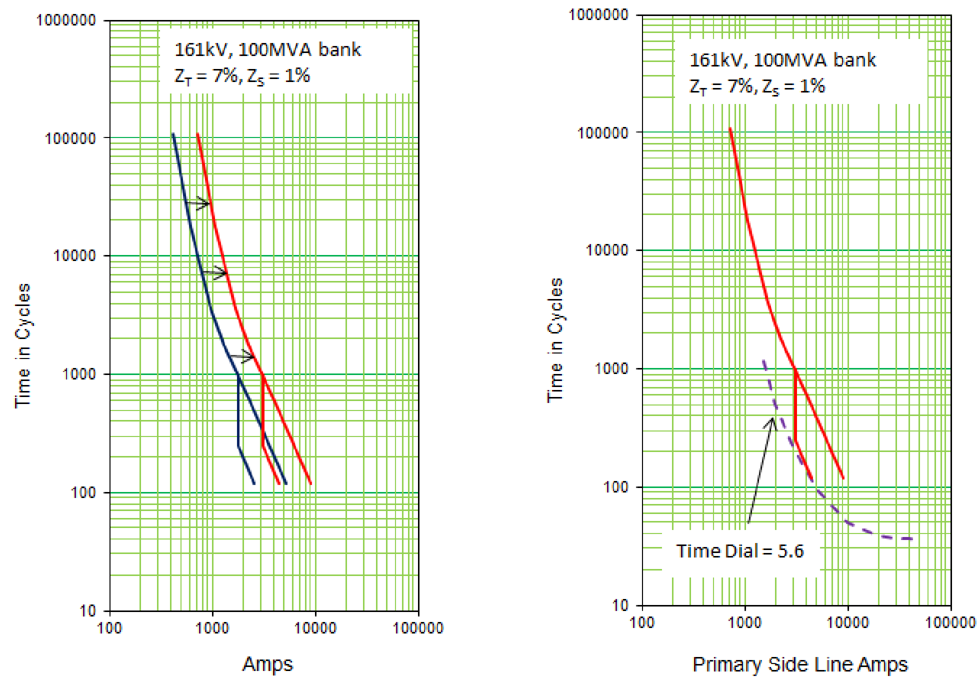


Figure 12 – Coordinating with Winding Damage Curve

Low-side Phase-Phase Fault

To check coordination for low-side phase-phase faults we will scale the primary winding damage curve as before to put it on the line-current basis with the relay. We notice from Figure 13 that our B-phase relay will have twice the current as either of the involved transformer primary windings whereas A- and C-phase relays will have the same current as experienced by each winding.

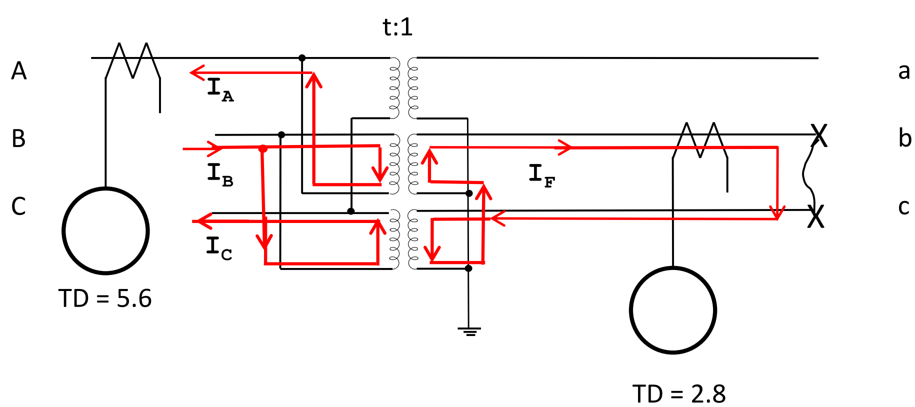


Figure 13 – Delta-wye transformer with secondary phase-phase fault.

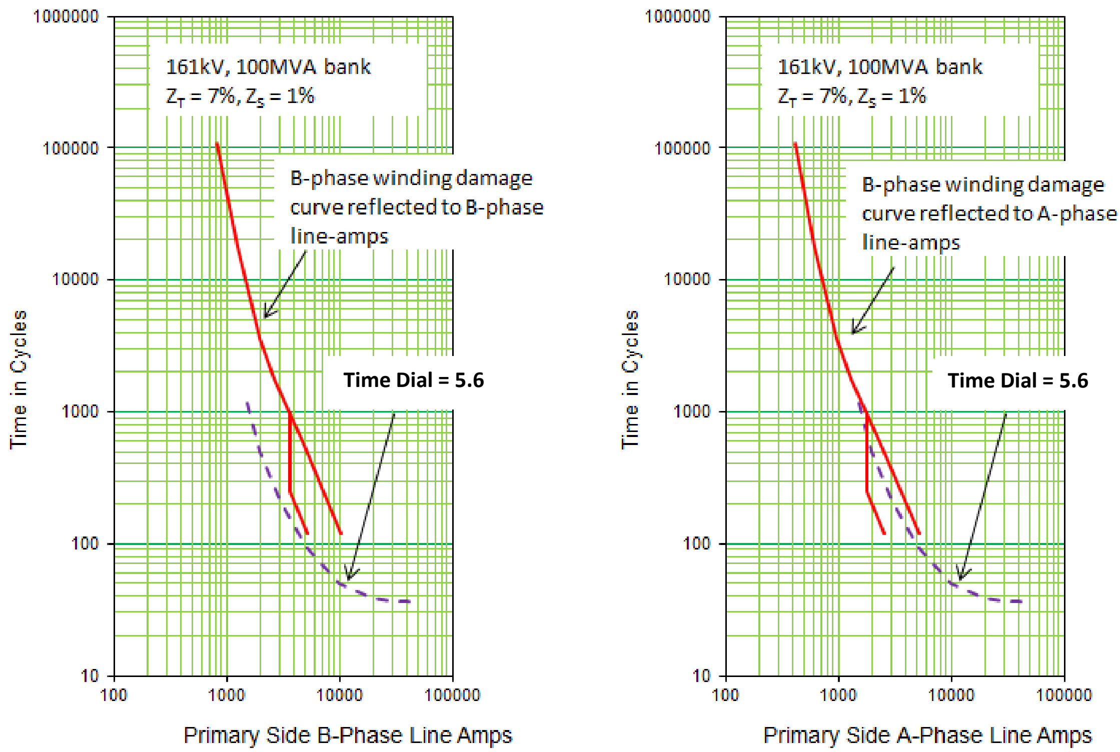


Figure 14 – Shifting winding damage curve to
B and A phase line current basis.

The left hand plot in Figure14 shows the B-phase winding damage curve reflected to the B-phase line current basis. The ratio used was ($I_B/I_W = 2$). The right hand plot below shows that same B-phase winding damage curve reflected to the A-phase line current basis. The ratio used in this case was ($I_A/I_W = 1$) so no shift occurred. From a first glance at the right hand plot it seems that our primary phase-time-overcurrent does not properly coordinate with (and protect) the winding damage curve. However, we recognize that for this fault our B-phase relay has twice the operate quantity as the A- and C-phase relays and will operate faster to provide the coordination we see on the left.

Low-side Phase-Ground Fault

To check coordination for low-side phase-ground faults we do not scale the primary damage curve because the ratio of $I_P/I_W = 1$. This can also be seen from Figure 9 where the primary line current is equal to the primary winding current. The coordination between the relay and damage curve is shown above in the right-hand plot of Figure 14. This shows incorrect coordination for the selected protection characteristic and requires selection of another characteristic providing suitable coordinating margin.

Other Winding Connections

Obviously, shifting of the transformer damage curve is not required for a wye-wye connected transformer. However, similar analysis for a delta-delta connected transformer should be done as well. We would shift the primary winding damage curve to the right by $\sqrt{3}$ to put it on the primary line-current base for low-side three-phase faults, and by 1.5 for low-side phase-phase faults. If you coordinate for the phase-phase case then you coordinate for the three phase fault types as well.

Number of Phases Operating Before Trip

Some relays can be set to require more than one individual phase overcurrent element to operate before producing a trip. They may be set to 1 out of 3, 2 out of 3, or 3 out of 3. Care should be taken to ensure the operational logic of the relay is fully understood and applied. When applying phase-time overcurrent protection on the primary of a transformer this setting should generally be set to allow tripping when only 1 element operates.

For example, if two phases where required to time-out and assert before tripping occurs in the scenario described in the previous section for a low side phase-phase fault of a delta-wye transformer, then the coordination would go from the left-hand plot in Figure 14 to the right-hand plot since the A- and C-phase elements experience half the current of the B-phase element. In this case the relay and damage curve would be incorrectly coordinated requiring A- and C-phase units to operate before a trip would be produced. This may or may not be desired depending on the coordination margin required and available for the low side relay.

Relays and other electronic protection devices measure current and operate based on each phase independently, but trip three-phase. Also, only one curve is selected regardless of fault type for protecting the transformer and coordinating with the low side relay. If the number of required operating phases is limited to one then the low side relay must coordinate with (operating before) Figure 14’s left side relay characteristic. If the number of required operating phases is set to two then the low side relay must coordinate with (operating before) Figure 14’s right side relay characteristic. Since this characteristic is the same that is required for a single phase to ground fault it may be desired to provide more available coordination margin for the low side relay.

Conclusions

The development of the transformer damage and a simple approach to coordination with it was presented. In the study of the delta-wye grounded connected transformer the phase-ground fault on the secondary was found to be the worst case for coordination between high-side phase-time-overcurrent protection and the transformer damage curve because the ratio of high-side line current to primary winding current is 1.0, the lowest value of any fault type. As such, the damage curve does not get shifted off to the right like it does for the three-phase ($\sqrt{3}$) and phase-phase faults (2.0). If you coordinate correctly for the phase-ground case then you coordinate for the other fault types as well.

There are many guides available from IEEE and vendors that provide various methods or charts of scaling factors by which you shift either the protection or damage curve. It is important to understand the basis for these factors so they can be properly applied. This approach just considered the shifting of the transformer damage curve to primary amps for different fault type allowing you to easily see the worst case and appropriately select your protection characteristic. This simple approach is easily understood and is least likely to cause confusion.

References

1. IEEE Standard C37.91 -2008, IEEE Guide for Protecting Power Transformers.
2. IEEE Standard C57.109 – 1993 (R 2003), IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration
3. IEEE Standard C57.91 – 2011, IEEE Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators.
4. IEEE Standard C57.12.00 – 2010, IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power and Regulating Transformers.
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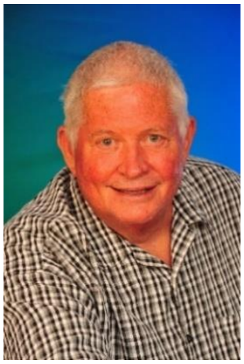
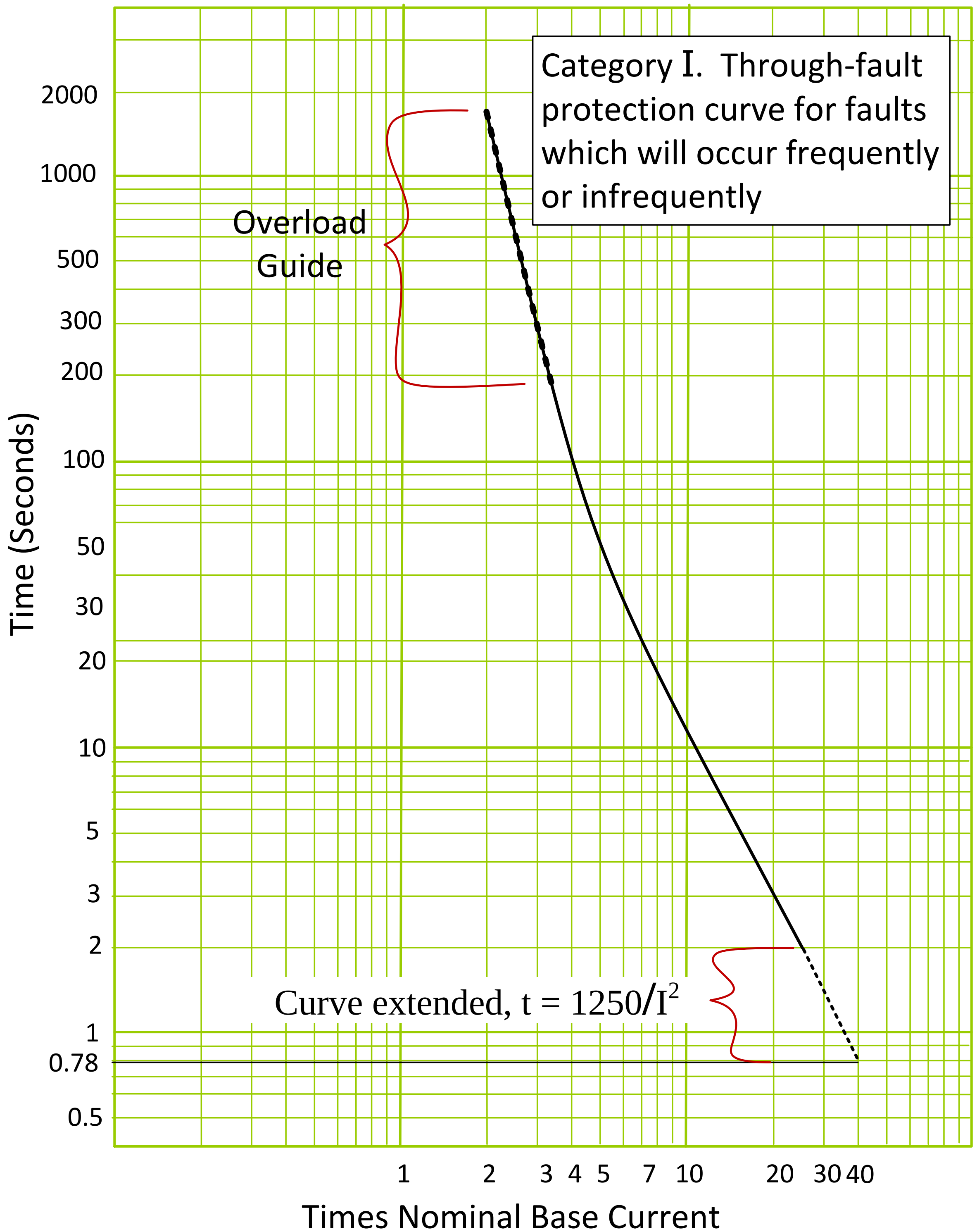
Biographies

Russell W. Patterson (SM 2002) received his BSEE in 1991 from Mississippi State University in Starkville, MS and his MSEE in 2013 from the University of Tennessee at Chattanooga, TN. He began his career as a field test engineer for TVA and has over twenty years' experience in utility generator and transmission protection and managed the system protection department for TVA until his retirement in 2008 to enter full time consulting. Russ owns Patterson Power Engineers (PPE), a consulting firm headquartered in Chattanooga, TN. He is a member of the IEEE Power System Relaying Committee where he is Secretary, a past chairman of the Line Protection Subcommittee, and an active member of the Rotating Machinery Subcommittee. He is an active member of CIGRÉ and a registered professional engineer. http://PattersonPowerEngineers.com

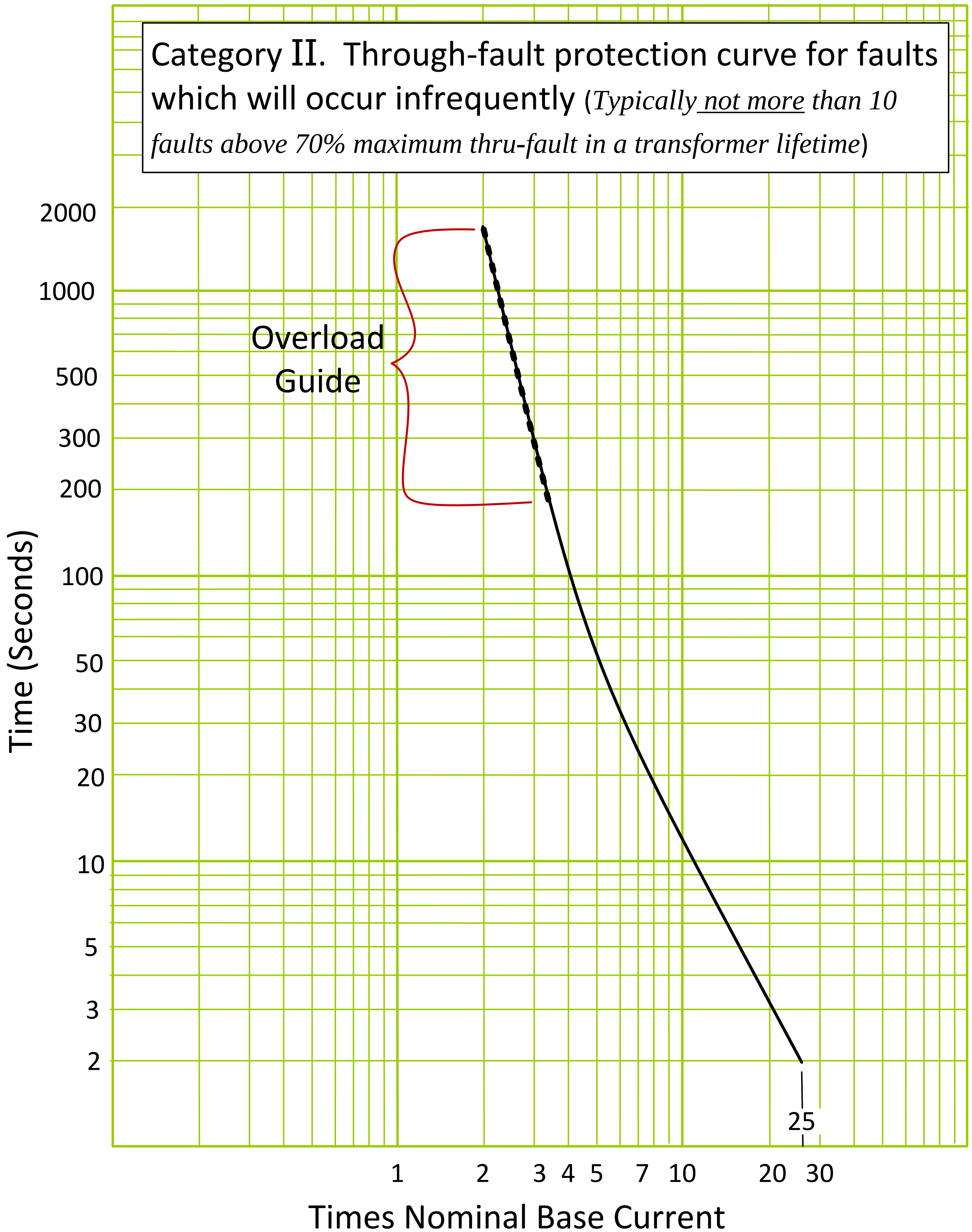


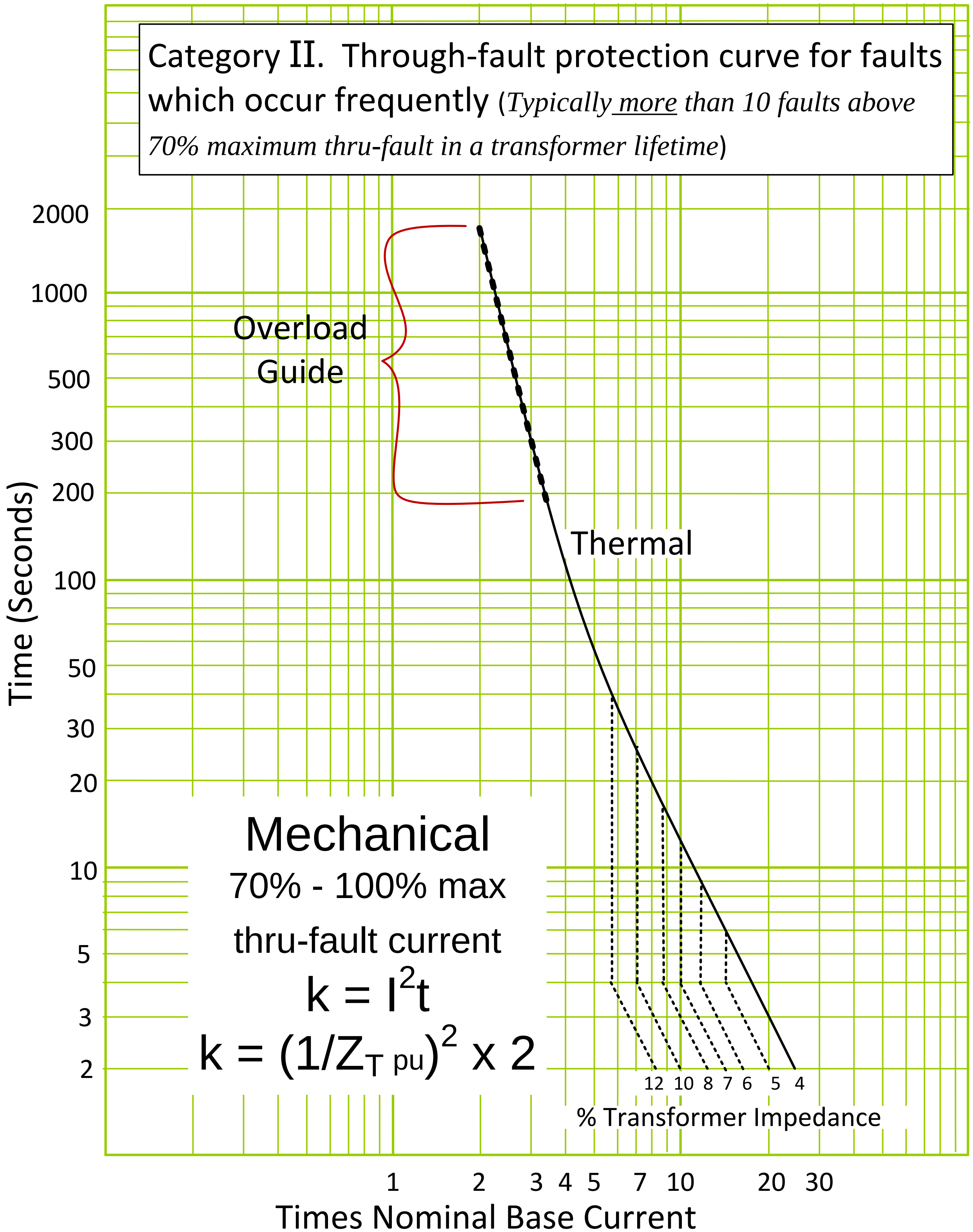
Elmo Price received his BSEE degree in 1970 from Lamar State College of Technology and his MSEE degree in 1978 from the University of Pittsburgh. He began his career with Westinghouse in 1970 and retired from ABB Inc. in 2014. Over his 44 year career he worked in several manufacturing divisions and field locations supporting the electric utility industry in many positions responsible for product management, product design, application support and relay schools. Elmo is a registered professional engineer and a Life Senior member of the IEEE. He is also a member of the IEEE Power System Relay Committee and the Line Protection Subcommittee, serving as a contributing member to many working groups. He has two patents and has authored and presented numerous industry papers. Email relmeaux@gmail.com

Appendix A. Transformer Short Circuit curves

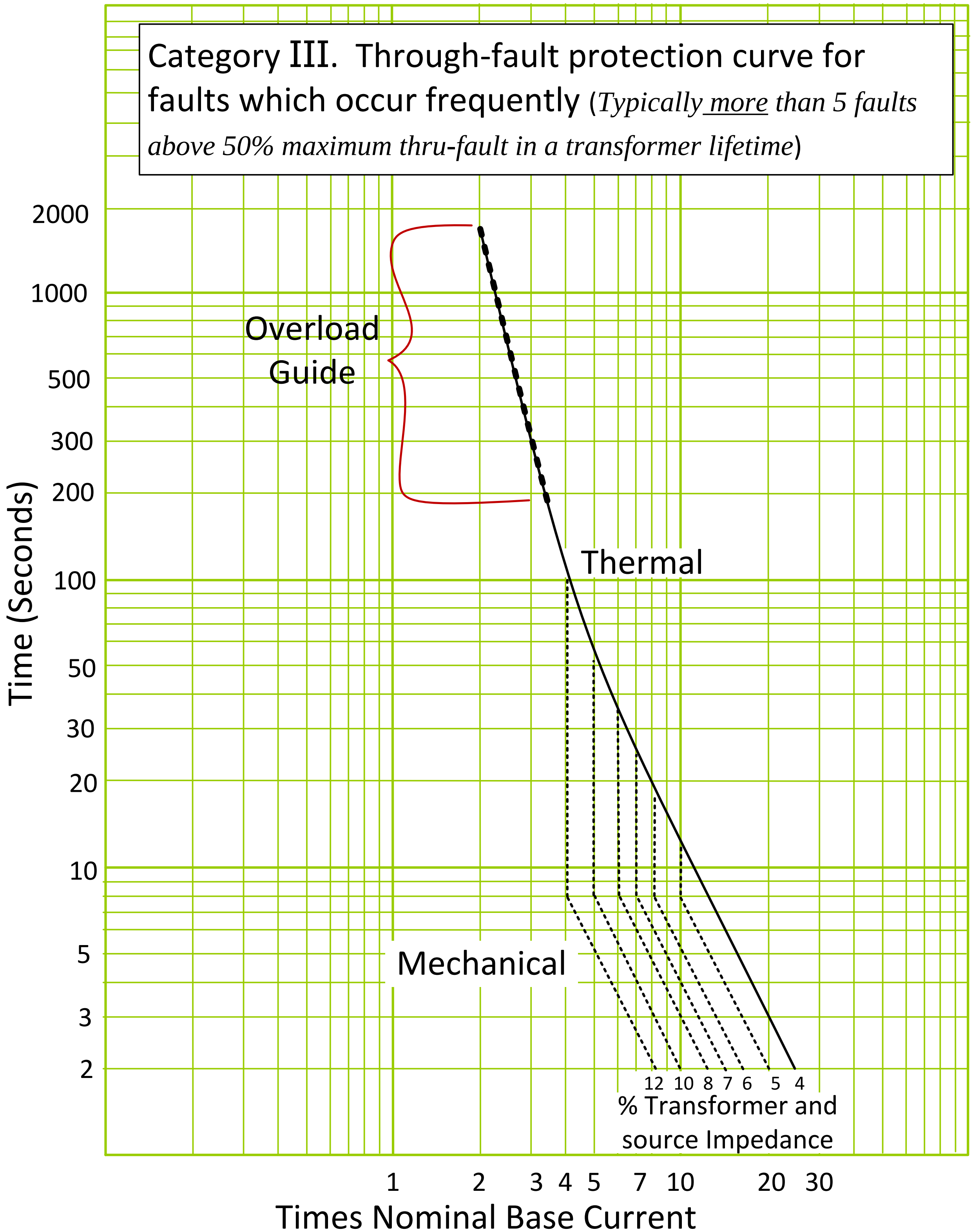


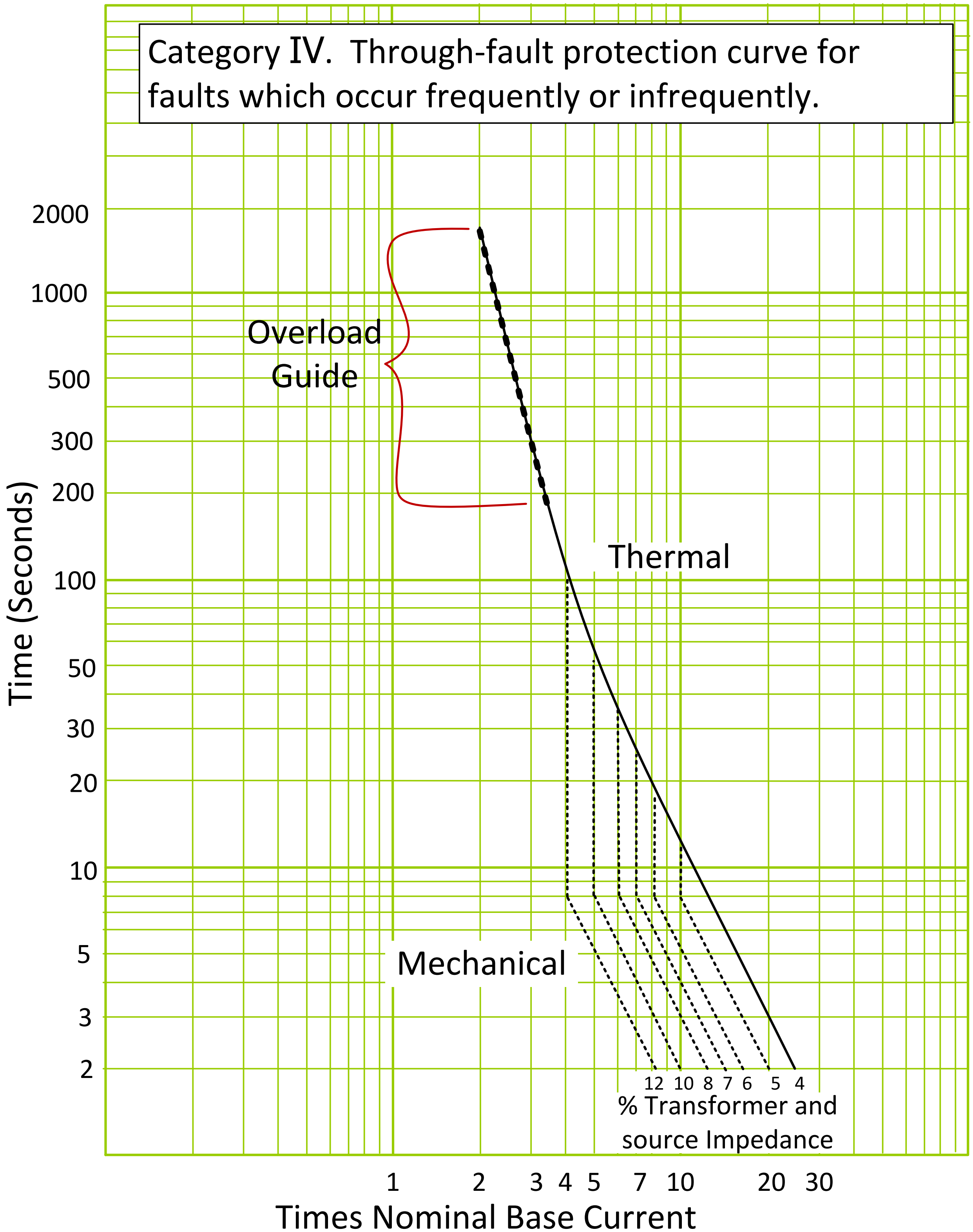
Overload Guide – C57.91 - 2011


Category II. Through-fault protection curve for faults which will occur infrequently (*Typically not more than 10 faults above 70% maximum thru-fault in a transformer lifetime*)
Overload Guide
2000
1000
500
300
200
100
50
30
20
10
5
3
2
Time (Seconds)
25
1
2
3
4
5
7
10
20
30
Times Nominal Base Current


Category II. Through-fault protection curve for faults which occur frequently (Typically more than 10 faults above 70% maximum thru-fault in a transformer lifetime)
Overload Guide
Thermal
Mechanical
70% - 100% max thru-fault current
$k = I^2t$
$k = (1/Z_{T\ pu})^2 \times 2$
12 10 8 7 6 5 4
% Transformer Impedance
Time (Seconds)
2000
1000
500
300
200
100
50
30
20
10
5
3
2
1 2 3 4 5 7 10 20 30
Times Nominal Base Current


Category III. Through-fault protection curve for faults which will occur infrequently (*Typically not more than 5 faults above 50% maximum thru-fault in a transformer lifetime*)
Overload Guide
Time (Seconds)
2000
1000
500
300
200
100
50
30
20
10
5
3
2
25
1
2
3
4
5
7
10
20
30
Times Nominal Base Current


Category III. Through-fault protection curve for faults which occur frequently (*Typically more than 5 faults above 50% maximum thru-fault in a transformer lifetime*)
Overload Guide
Thermal
Mechanical
12 10 8 7 6 5 4
% Transformer and source Impedance
Time (Seconds)
2000
1000
500
300
200
100
50
30
20
10
5
3
2
1 2 3 4 5 7 10 20 30
Times Nominal Base Current


Category IV. Through-fault protection curve for faults which occur frequently or infrequently.
Time (Seconds)
2000
1000
500
300
200
100
50
30
20
10
5
3
2
Overload Guide
Thermal
Mechanical
12 10 8 7 6 5 4
% Transformer and source Impedance
1 2 3 4 5 7 10 20 30
Times Nominal Base Current