STUDY OF CURRENT TRANSFORMER PERFORMANCE DURING TRANSIENT CONDITIONS AND DEVELOPMENT OF A SELECTION CRITERION IN PROTECTION APPLICATIONS

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DECLARATION

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ABSTRACT

The optimum selection of current transformers is one of the most crucial requirements of correct protection functioning of power systems. In the case of CT selection, protection engineer has to pay attention on transient behavior as well as steady state performance of current of transformers. Transient performance of current transformers varies with system parameters and current transformer parameters. System parameters vary with fault level and inductance to resistance ratio (L/R) at fault location. In Sri Lankan power system, these parameters rapidly vary due to network development. Type of selected protection relay, type of protection function and switchgear arrangement make huge influence on current transformer selection. This dissertation focuses on developing a current transformer selection criterion with analysis of current transformer transient performance and protection application. The developed selection criterion is mainly focused on protection relay based selection and generalized CT selection.

In addition to analysis of the current transformer transient performance, PSCAD software is used for current transformer performance simulation on fault conditions and a case study is used to validate the developed selection criteria.

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LIST OF ABBREVIATION

AIS	Air Insulated Switchgear
ALF	Accuracy Limit Factor
CT	Current Transformer
CVT	Capacitive Voltage Transformer
E_{al}	Rated Equivalent Limiting Secondary e.m.f.
E_{ALF}	Secondary Limiting e.m.f. for Class P and PR Protective Current Transformers
E_{FS}	Secondary Limiting e.m.f for Measuring Current Transformers
E_k	Rated Knee Point e.m.f.
F	Mechanical Load
F_c	Factor of Construction
f_R	Rated Frequency
F_{rel}	Relative Leakage Rate
FS	Instrument Security Factor
GIS	Gas-Insulated Switchgear
$\hat{I}_{al}$	Peak Value of the Exciting Secondary Current at Eal
I_{cth}	Rated Continuous Thermal Current
I_{dyn}	Rated Dynamic Current
I_e	Exciting Current
I_{PL}	Rated Instrument Limit Primary Current
I_{pr}	Rated Primary Current
I_{psc}	Rated Primary Short-Circuit Current
I_{sr}	Rated Secondary Current
IT	Instrument Transformer
I_{th}	Rated Short-Time Thermal Current
I_{ε}	Instantaneous Error Current
K	Actual Transformation Ratio
k_r	Rated transformation ratio
K_R	Remanence Factor
K_{ss}	Rated Symmetrical Short-Circuit Current Factor

K_{td}	Transient Dimensioning Factor
K_{tf}	Transient Factor
K_x	Dimensioning Factor
L_m	Magnetizing Inductance
R_b	Rated Resistive Burden
R_{ct}	Secondary Winding Resistance
R_s	Secondary Loop Resistance
S_r	Rated output
t'	Duration of the First Fault
t''	Duration of the Second Fault
t'_{al}	Specified Time to Accuracy Limit in the First Fault
t''_{al}	Specified Time to Accuracy Limit in the Second Fault
t_{fr}	Fault Repetition Time
T_P, T_N	Specified Primary Time Constant
T_S	Secondary Loop Time constant
U_m	Highest Voltage for Equipment
U_{sys}	Highest Voltage for System
VT	Voltage Transformer
Δ_φ	Phase Displacement
ε	Ratio Error
ε_c	Composite Error
$\hat{\varepsilon}$	Peak Value of Instantaneous Error
$ac\hat{\varepsilon}$	Peak Value of Alternating Error Component
Ψ_r	Remanent Flux
Ψ_{sat}	Saturation Flux

CHAPTER 1

INTRODUCTION

1.1 Background

Current transformers (CT) play a vital role in protection and measuring functions of a power system. Correct selection of current transformers leads to proper operation of protection and instrumentation of the power system. Current transformer behavior due to magnetic saturation of its core brings out undesirable problems on the protection devices of the power system. Hence, the current transformers must be designed correctly to activate the protection devices during fault condition of power system.

During fault conditions, DC component of the fault current is responsible for the saturation of the current transformer. The ratio of inductance to resistance (L/R) at location of fault and the L/R ratio of the secondary loop determine the magnitude and the decaying time of the direct current (DC) component of CT secondary current. Changing hardware of the transmission system changes L/R ratio of power system. Meanwhile, addition of generators to power system increases its fault levels. These factors create considerable problems on existing CTs and protection functions.

CT errors due to saturation or mismatch have an adverse impact on protection functions and hence on system stability. Saturation of CT can be avoided by selecting an oversized CT, but it cannot be justified economically. Expansion of generation, transmission of power systems is a continuous process and hence duties of CTs have to be performed, and this would become more and more demanding. Therefore the utility needs proper selection criteria when procuring new CTs or replacing existing CTs.

1.2 Objective

Like any other power system in the world, Sri Lanka also has replaced all its electro-magnetic relays and static relays with modern numerical protection relays. The conventional electromagnetic relays take nearly more than sixth cycles for operation of instantaneous protection functions. During this sixth cycle delay, the dc component of fault current decays from sub transient time zone to transient and this causes to minimize effects from transient current for the operation of the protection relay. Old bulk oil circuit breaker consumes nearly 15 cycles for a tripping operation. Such delayed clearing times did not warrant to commission detailed studies on the behavior of current transformers during the first few cycles of a fault. As a result attention was constantly focused on the CT steady state performance.

Globally, power systems expansions and interconnections have been continuing at a very rapid rate along with large additions of generation. Transmission systems and large additions of generation take place even for islanded power systems like that of Sri Lanka. To maintain the system stability under these scenarios, fault-clearing time has to be made much lower with numerical relays and fast acting circuit breakers. Advent of numerical relays and high-speed circuit breakers achieved the lower fault clearing time as desired, but the questions began arising on the capability of the current transformers to feed the relevant information to relay, as the CTs were based on steady state performance.

In case of instantaneous protection functions (differential and distance), numerical relay operation takes place in the sub transient period. Therefore, protection engineers and CT manufacturers have focused their attention to cater for satisfactory CT transient performance. IEC has published its standards on transient performance of CTs. Most countries have taken steps to follow the new standards to improve the protection performance, and CEB has also taken initial steps to examine the necessity of adapting the new standard, but so far, all CTs in the system are based on steady state performance standards.

The main objectives of this study are as follows.

a) To study current transformer performance under transient conditions and its impact on protection functions.

b) To revisit present selection criteria and to develop a generalized current transformer selection criterion based on system parameters and current transformer parameters for different protection functions.

CHAPTER 2

GENERAL THEORY AND THE ANALYSIS OF CURRENT TRANSFORMER BEHAVIOR UNDER TRANSIENT CONDITIONS

2.1 Parameters that govern CT performance under-transient conditions

Transient performance of current transformers depends on following parameters.

a) Fault level or fault current at particular location
b) Primary time constant (T_P)
c) Secondary time constant (T_S)
d) Burden of CT secondary
e) Remanence flux of CT core
f) Number of secondary turns and cross section area of CT

2.2 Fault current variation with system parameters

2.2.1 Fault inception angle and fault loop impedance

The magnitude of DC component of fault current varies with fault inception angle and power factor of fault impedance and the total fault current at any instant is defined by the equation (1) [1].

$$i_p=\frac{V\sqrt{2}}{Z}\left\{\sin\left(\omega t+\alpha-\emptyset\right)-\sin\left(\alpha-\emptyset\right)e^{-\frac{t}{\tau_p}}\right\} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots. (1)$$

i_p = Instantaneous value of fault current

$\frac{V\sqrt{2}}{Z}$ = I_P, Peak Fault current

α = Angle of fault inception

$\emptyset$ = Phase angle of the fault impedance

Z = Fault loop impedance

Magnitude of DC component $(\sin(\alpha\text{-}\emptyset)\, e^{-\frac{t}{\tau_p}})$ varies with angle $(\alpha\text{-}\emptyset)$ and will be maximum when $(\alpha\text{-}\emptyset)\text{=-}90^0$. In the case of transmission lines, typical values of $\emptyset$ lie around 90° or fault impedance is highly inductive. As can be seen, the DC component is a function of fault inception angle and fault loop impedance. This indicates that, if fault inception angle equals zero or near zero, the DC component will also assume its maximum value. However, fault inception angle will vary and cannot be predicted. Hence, CT sizing is carried out for the worst case or assuming the DC component to be at its maximum. Equation (2) gives instantaneous fault current with zero fault inception angle and pure inductive fault loop impedance or when $(\alpha\text{-}\emptyset)\text{=-}90^0$ [2].

$$i_p\text{=}I_p\left[e^{-\frac{Rt}{L}}\text{-}\cos\omega t\right] \text{……………………………. (2)}$$

2.2.2 Fault current variation with primary time constant (T_P)

Primary Time constant (T_P) is defined as L/R ratio of fault location and determines the decaying time of the DC component of the fault current .Very high primary time constant leads to very high decaying time of the DC component of the fault current (Figure 2.1).

T_P makes a high impact on the flux development in the CT core and plays a vital role in CT sizing. The flux development in closed (very low leakage flux in secondary) core application is shown in figure 2.3

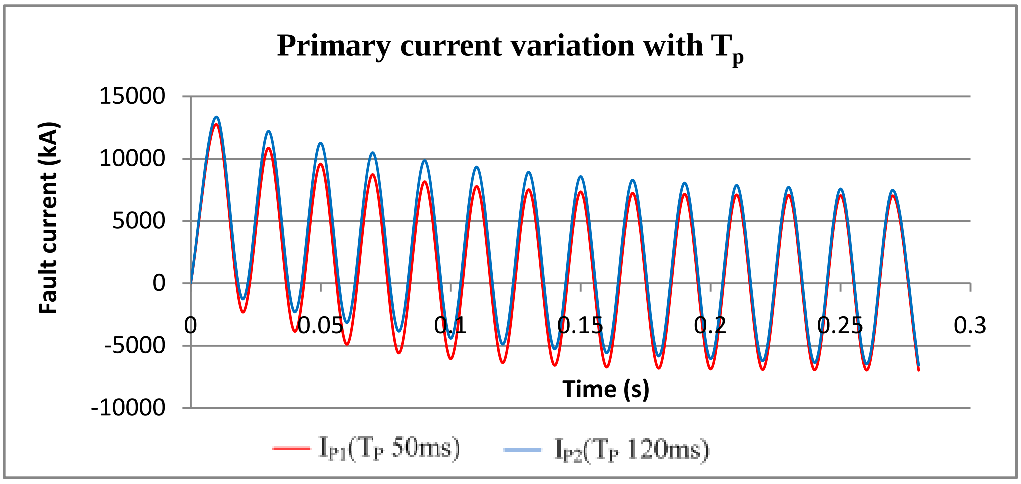

Figure 2-1: Primary Current Variation with Tp

2.3 CT Flux requirement under transient condition

The CT flux requirement under transient condition can be derived as follows [3]. Consider the equivalent circuit in Figure 2.2 with the following assumptions.

1) With ring type CT with number of primary side turns equals to one ($N_1=1$) and number of secondary side turns equals to N_2 and the turns ratio is $1/N_2$.
2) With fully offset current (fault inception angle = 0°, so the fault impedance fully inductive).

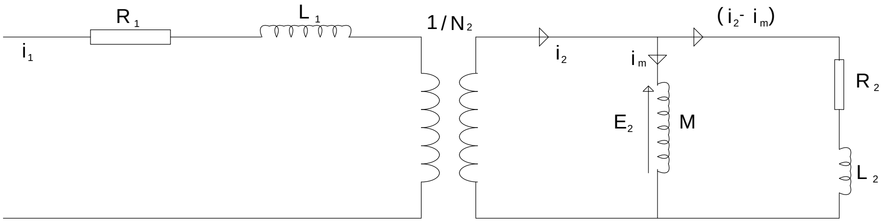

Figure 2-2: Equivalent circuit of a CT

R_1 = Primary resistance of CT

R_2 = Total secondary resistance

M = Magnetic inductance

L_1 = Primary leakage inductance of CT

L_2 = Secondary leakage inductance

$$i_1 = I_1\left[e^{-\frac{t}{T_P}} - \cos\omega t\right] \text{ ……………………………………. (3)}$$

$$i_2 = \frac{1}{N2} I_1\left[e^{-\frac{Rt}{L}} - \cos\omega t\right] \text{ ………………………………….. (4)}$$

E_2 = secondary induced e.m.f

$$E_2 = N_2\frac{d\emptyset}{dt} \text{ ……………………..……………….………… (5)}$$

Also,

$$E_2 = \left(i_2 - i_M\right)R_2 + L_2\frac{d\left(i_2 - i_M\right)}{dt} \text{ …………………………….. (6)}$$

$$i_M = \frac{N_2}{M}\emptyset \text{ ……………………………..……………….……… (7)}$$

Where M is a constant

$$N_2\frac{d\emptyset}{dt} = i_2R_2 - \frac{N_2R_2\emptyset}{M} + \frac{L_2di_2}{dt} - \frac{L_2N_2}{M}\frac{d\emptyset}{dt} \text{ ……………………. (8)}$$

$$\frac{d\emptyset}{dt}\left(N_2 + \frac{L_2N_2}{M}\right) + \frac{N_2R_2\emptyset}{M} = i_2R_2 + \frac{L_2di_2}{dt} \text{ …………………………. (9)}$$

We get solution for Ø (Applicable t>8.3ms) [3]

$$\emptyset = \frac{I_1R_2}{N_2 2\omega}\left(\frac{T_PT_S\omega}{\left(T_S - T_P\right)}\left(e^{\frac{-t}{T_S}} - e^{\frac{-t}{T_P}}\right) - \frac{1}{\cos\theta}\sin(\omega t + \theta)\right) \text{……….. (10)}$$

Where $\theta = \tan^{-1}\frac{L_2\omega}{R_2}$ $\quad T_S = \frac{L_2 + M}{R_2}$ $\quad T_P = \frac{L_1}{R_1}$

Core flux is a function of time, primary current, turns ratio, primary time constant, secondary time constant and burden. Figure 2-3 shows flux development in a CT core having a 1000ms secondary time constant[1] for different time constants of $\emptyset_{@140ms}$, $\emptyset_{@120ms}$, $\emptyset_{@60ms}$ values.

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[1] In CT sizing, 1000ms value can be considered as infinite.

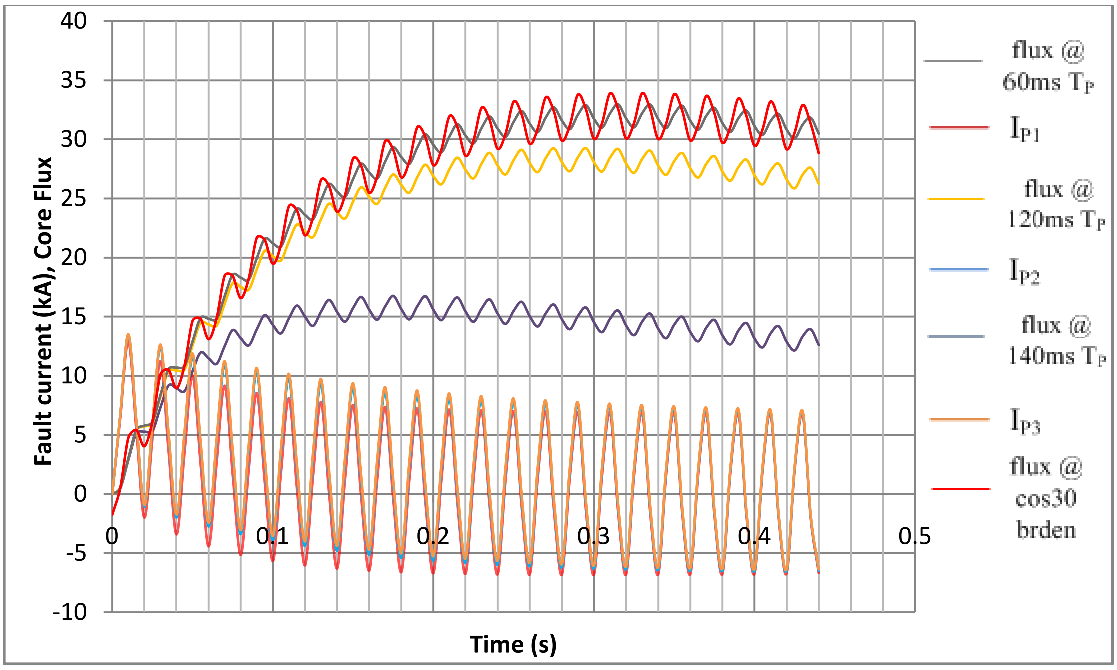

Figure 2-3: Development of CT core flux with different T_P and constant T_S (1000ms)

Figure 2.4 shows core flux variation with very low secondary time constant. 300ms is taken as T_S and this shows rapid decaying of flux that involves with DC current component. This characteristic can be utilized for minimizing the growing flux component due to DC primary current. In such cases, gapped cores are used to reduce secondary time constant.

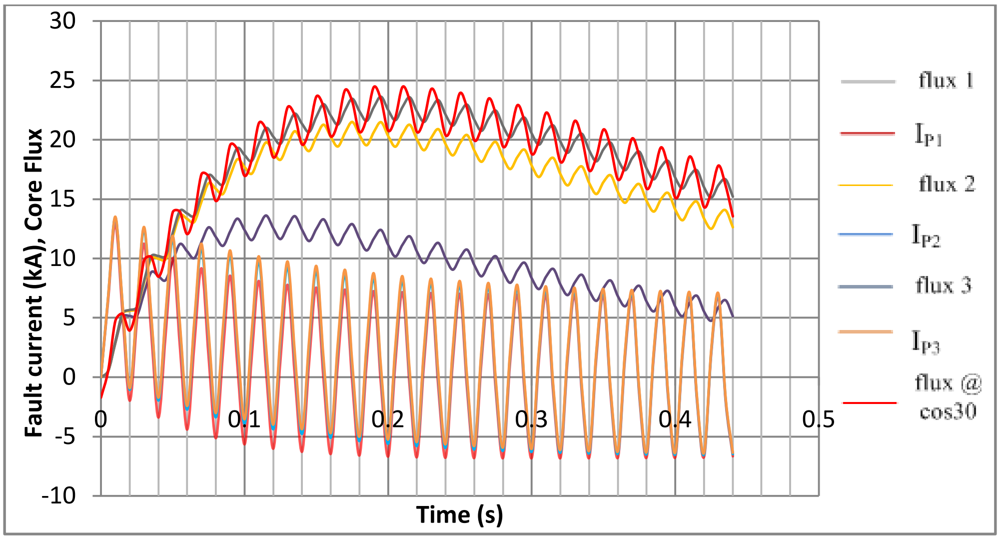

Figure 2-4: Variation of core flux with low T_S

The burden inductance has an effect on the peak flux developed in the CT core. Electro-Magnetic type protection relays are mainly inductive. However, modern Numerical relays have negligible inductance. The variation of the peak flux in the CT core and the burden inductance is analyzed in Figure 2.5.

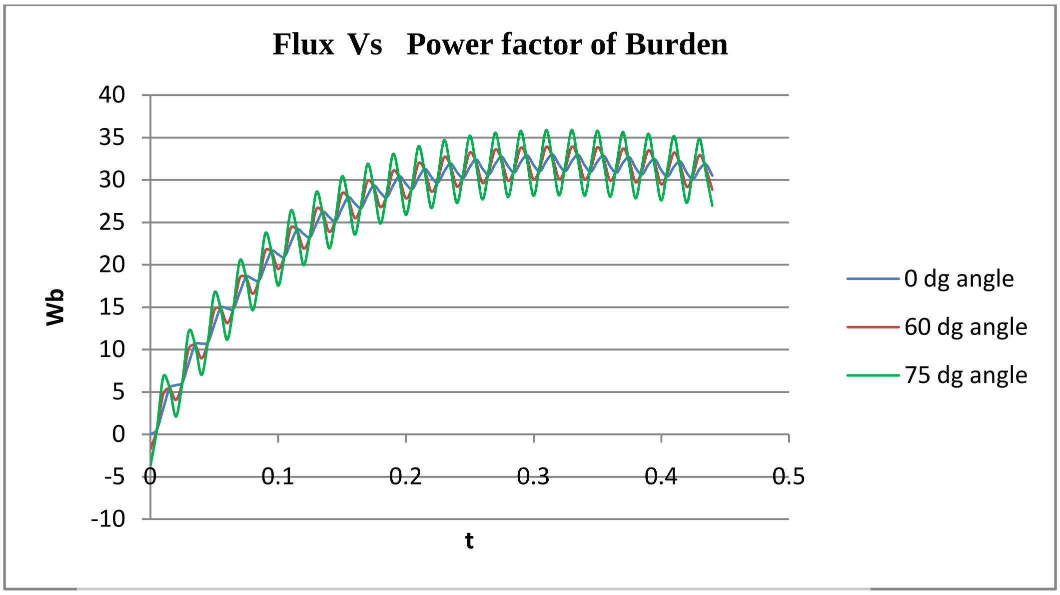

Figure 2-5: Variation of core flux with secondary power factor of burden

2.3.1 CT Flux requirement under transient conditions with a fully resistive burden

In this case, $\cos\theta = 1$, $\theta = 0$, Substitutes to equation (10)

$$\emptyset = \frac{I_1R_2}{N_2 2\omega}\left(\frac{T_PT_S\omega}{(T_S-T_P)}\left(e^{\frac{-t}{T_S}} - e^{\frac{-t}{T_P}}\right) - \sin(\omega t)\right)\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (11)$$

CHAPTER 3

CURRENT TRANSFORMER DIMENSIONING

3.1 Introduction

Protection current transformers must be capable of making correct performance in steady state as well as in transient state. The dc component contained in a fault current results single directional growing flux in CT core and CT core must be of sufficient size to avoid saturation. Optimum CT sizing process is called as CT dimensioning. Correct dimensioning is one of the most important factors for proper protection operation. CT dimensioning calculations are based on transient factor (K_{tf}) and transient dimensioning factor (K_{td}). Network, CT and relay parameters are needed for dimensioning calculation.

3.2 Transient factor (K_{tf})

The transient factor is defined as ratio of the theoretical total linked flux to the peak instantaneous value of the ac component of the flux when a current transformer is subjected to a specified single energization and secondary loop time constant (T_S) is assumed to have retained a constant value throughout the energization [1].

$$K_{tf}=\left(\frac{T_P T_S \omega}{(T_S-T_P)}\left(e^{\frac{-t}{T_S}}-e^{\frac{-t}{T_P}}\right)-\sin(\omega t+\theta)\right)\text{.............................}\ (12)$$

3.3 Transient dimensioning factor (K_{td})

A factor that has been assigned to indicate the transient dimensioning necessary to ensure that the current transformer will be able to meet the specified performance requirements including the requirements necessary under the specified duty cycle[1].

This is the final parameter for CT sizing in protection applications. It defines the dimensioning necessary to ensure that the CT will be able to meet the performance requirements due to the increase of secondary linked flux resulting from the DC component of the primary short circuit current. K_{td} is derived from K_{tf} and it is a function of time, which depends on selected protection relay parameters or calculated value evaluating all network and CT parameters. This defined value for time is termed as the required ‘saturation free time (T_{al})’ for proper operation of protection function and often given by the relay manufacturer, based on the relay type tests. Theoretical quantification of K_{td} is categorized into three time zones [2].

3.3.1.1 1st time zone ($0 \leq T_{al} \leq T_{al1}$)

$$T_{al\,1} = \frac{\pi+\varphi}{\omega} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (13)$$

$$\varphi = \tan^{-1} \omega T_p$$

Figure 3.1 shows total flux development and ac flux development of CT core in first few cycles. In first half cycle, K_{td} lays nearly less than one or it indicates that if $T_{al} \leq$ 10ms and K_{td} requires very low value in CT sizing. Figure 3.1 shows flux development in first few cycles and Flux relationship of K_{td} is given bellow.

$$K_{td} = \frac{\text{Secondary linked flux due to actual transient current (AC + DC)}}{\text{Secondary linked peak flux of AC component only}}$$

In first half cycle, sinusoidal component dominates in K_{td} sizing.

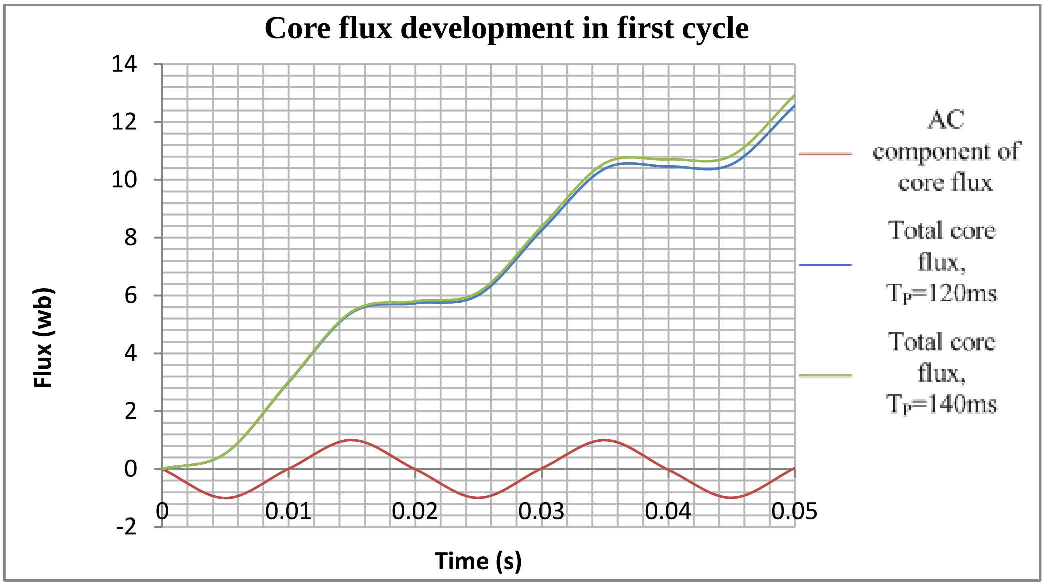

Figure 3-1: CT core flux development in the initial stages of a short circuit

In the CEB transmission system, Maximum T_p is around 140ms and using the equation (13) [2].

$$T_{al1}=\frac{\frac{22}{7}+\tan^{-1}\left(2\times\frac{22}{7}\times 50\times 0.14\right)}{2\times\frac{22}{7}\times 50}$$

T_{al1}=10.6ms

That means T_{al1} just exceeds a half a cycle. T_{al} requested by modern numerical relays are in this time zone and due to this reason, K_{td} required for satisfactory performance becomes a very low value.

3.3.1.2 2nd time zone ($T_{al1} \leq T_{al} \leq T_{al\ @\ B\ max}$)

In this time zone, K_{td} can be quantified by equation (14) [2].

$$K_{td}=\left(\frac{T_P T_S \omega}{(T_S-T_P)}\left(e^{\frac{-T_{al}}{T_S}}-e^{\frac{-T_{al}}{T_P}}\right)+1\right) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (14)$$

Figures 2.3 and 2.4 show the flux variation with primary time constant (T_P) and secondary time constant (T_S) respectively. Figure 3.2 indicates that if time constant goes high after 500ms, it makes less influence on K_{td} sizing. If T_P equals to T_S, K_{td} has a very small value.

In the case of electro-magnetic relays and static relays, defined saturation free time lay in this second time zone.

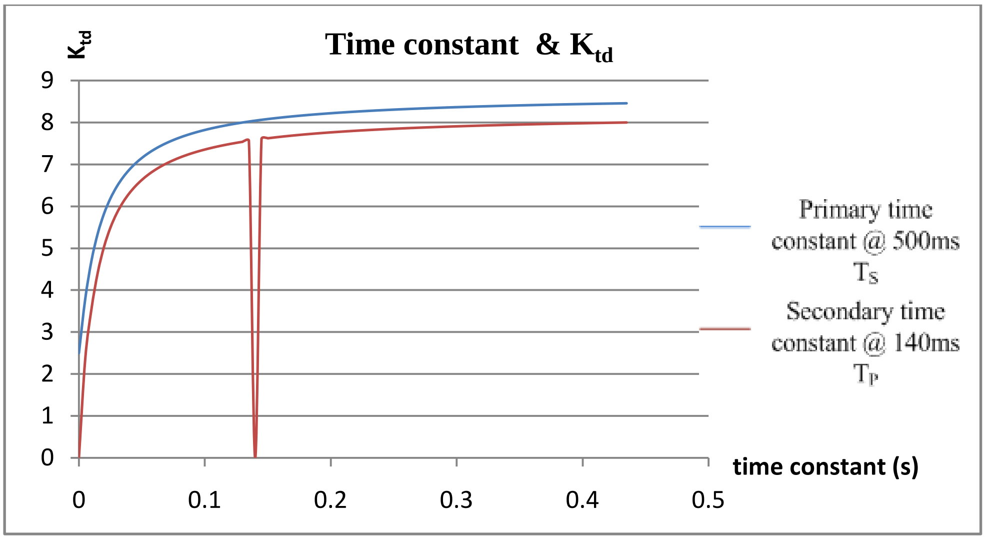

Figure 3-2: Variation of time K_{td} with primary and secondary time constants

3.3.1.3 **3rd time zone ($T_{al} \geq T_{al@Bmax}$)**

$T_{al@Bmax}$ is defined as time taken for core flux to reach maximum. Time beyond $T_{al@Bmax}$, core flux starts to decay. Mathematical expression for maximum flux in CT core is given by equation (15) and time taken reach maximum flux ($T_{al@Bmax}$) is given by equation (17) [2].

$$\frac{B}{B_{ac}} = K_{ft} = \left(\frac{T_P T_S \omega}{(T_S - T_P)}\left(e^{\frac{-t}{T_S}} - e^{\frac{-t}{T_P}}\right) + 1\right) \text{..............................} \; (15)$$

$$\frac{B_{max}}{B_{ac}} = K_{td(max)} = 1 + \omega T_S\left[\frac{T_P}{T_S}\right]^{\frac{T_S}{(T_S - T_P)}} \text{..............................} \; (16)$$

$$T_{al\,@B\,max} = \frac{T_P T_S}{T_S - T_P}\, l_n \frac{T_S}{T_P} \text{..} \; (17)$$

This time zone is more important to CT sizing for possible maximum core flux or extreme saturation free time. In the case of static and electromagnetic relays for differential protection application, due to sizing requirement of through fault condition CT must provide saturation free current input to protection relay for entire fault period .Therefore this $T_{al@Bmax}$ value must be considered in CT sizing of differential protection with electro-magnetic and static relays (relay which free from saturation detection). Figure 3.3 shows $T_{al@Bmax}$ variation with primary time constant in closed core CTs and Figure 3.4 shows $K_{td(max)}$ variation with primary time constant and secondary time constant.

If fault critical clearing times are available for unprotected zones by differential protection and this critical clearing time less than $T_{al@Bmax}$, then this critical clearing time can be used for as T_{al} in K_{td} calculation. In generally this K_{td} value less than value of $K_{td(max)}$ which we taken from equation (16). This new K_{td} is optimum, however massive trust must be given for entire protection and breaker operation in critical clearing time.

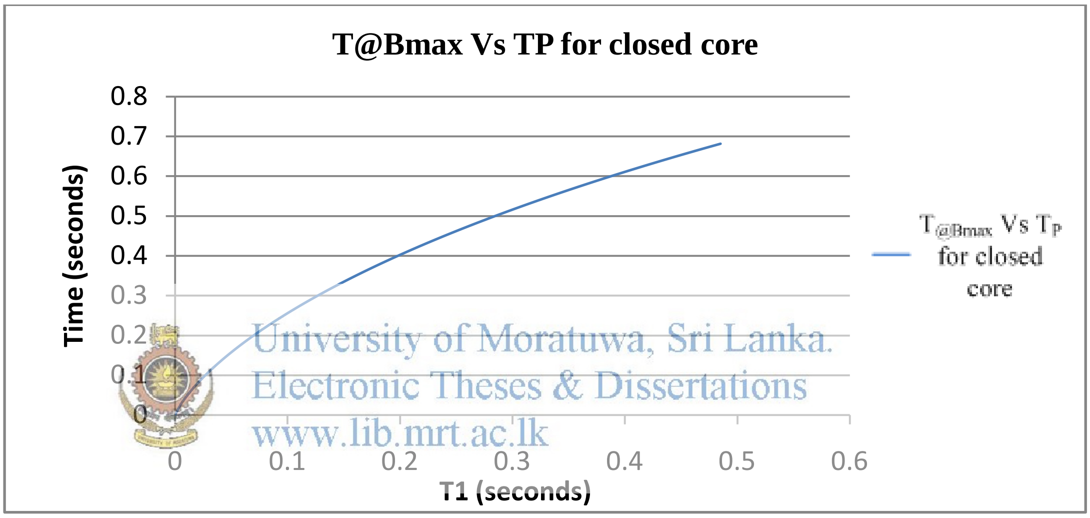

Figure 3-3: Variation of time taken reach maximum flux with primary time constant

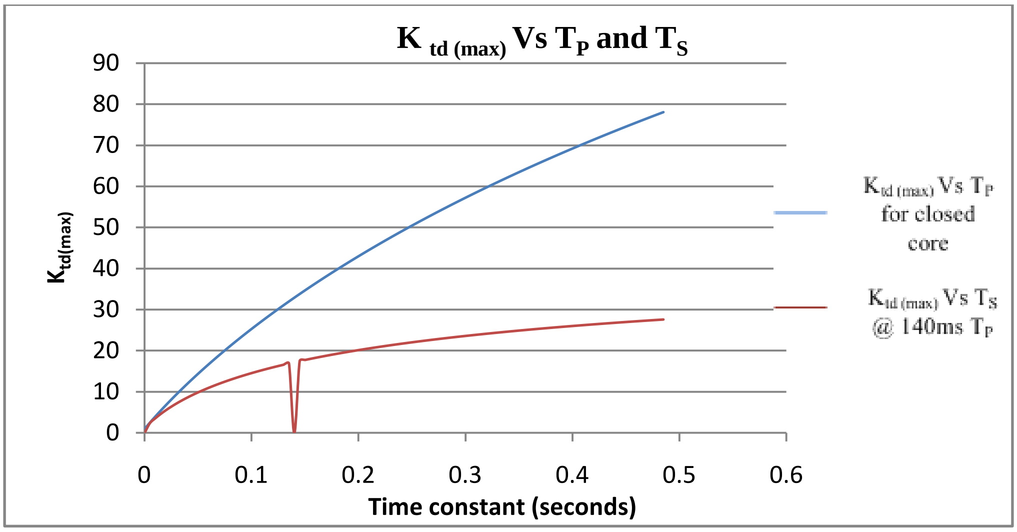

Figure 3-4: Variation of over dimensioning factor (maximum) with primary and secondary time constant

3.4 CT secondary current

Undistorted CT secondary current replica is an important parameter for proper protection functioning of the power system. In fault transients, a CT secondary current varies with CT parameters. The Maximum DC offset primary current occurs at ("∝-Ø") = -90° and equation (2) gives relationship of primary fault current with primary time constant. Equation (18) gives [4] corresponding secondary current.

$$i_S = \frac{I_P N_P}{N_S T_P}\left[\frac{e^{\frac{-t}{T_P}} - e^{\frac{-t}{T_S}}}{\frac{1}{T_P} - \frac{1}{T_S}}\right] + \frac{I_P N_P \omega^2}{N_S}\left[\frac{e^{\frac{-t}{T_S}} - \cos\omega t + \frac{1}{\omega T_S}\sin\omega t}{\left(\frac{1}{T_S{}^2} + \omega^2\right)}\right] \quad \ldots\ldots\ldots\ldots\ldots\ldots (18)$$

The magnitude and decaying time of DC current component of secondary current largely depends on secondary time constant. The closed core CTs provide very low leakage inductance and high secondary time constant. Gapped core CTs give high leakage inductance and low secondary time constant. Very low secondary time constant contributes to a rapid decay of DC current component in secondary current. Figure 3.5 shows DC current component decaying with secondary time constant.

High secondary time constant makes correct current replica in secondary. Closed core CT provides more correct secondary current wave due it very high time constant. Figure 3.6 gives detail comparison of secondary current with different values of secondary time constants. This graph is developed on equation (18) and it is considered that turns ratio as 1:1.

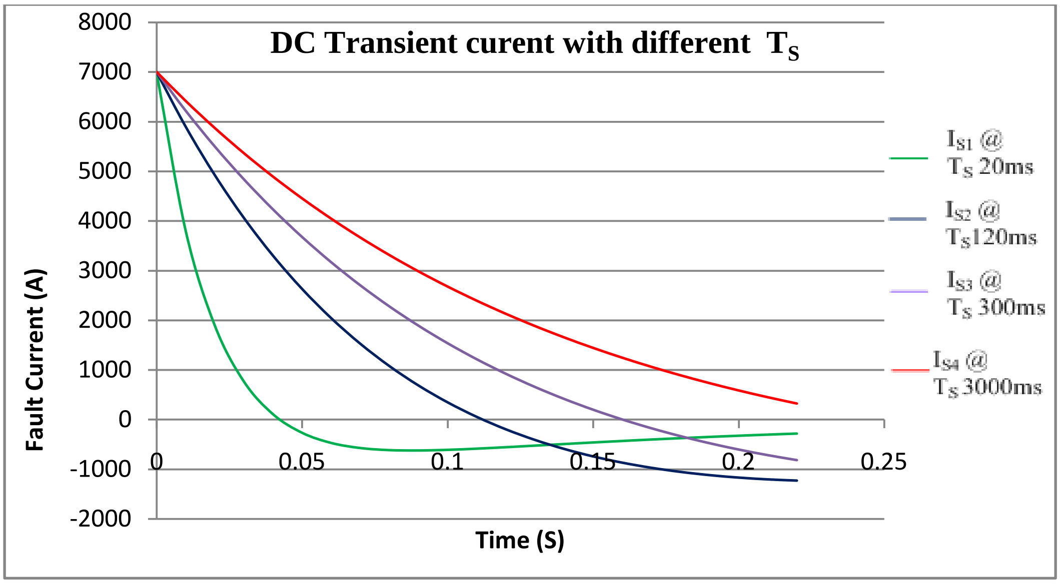

Figure 3-5: Variation of secondary DC current component with secondary time constant

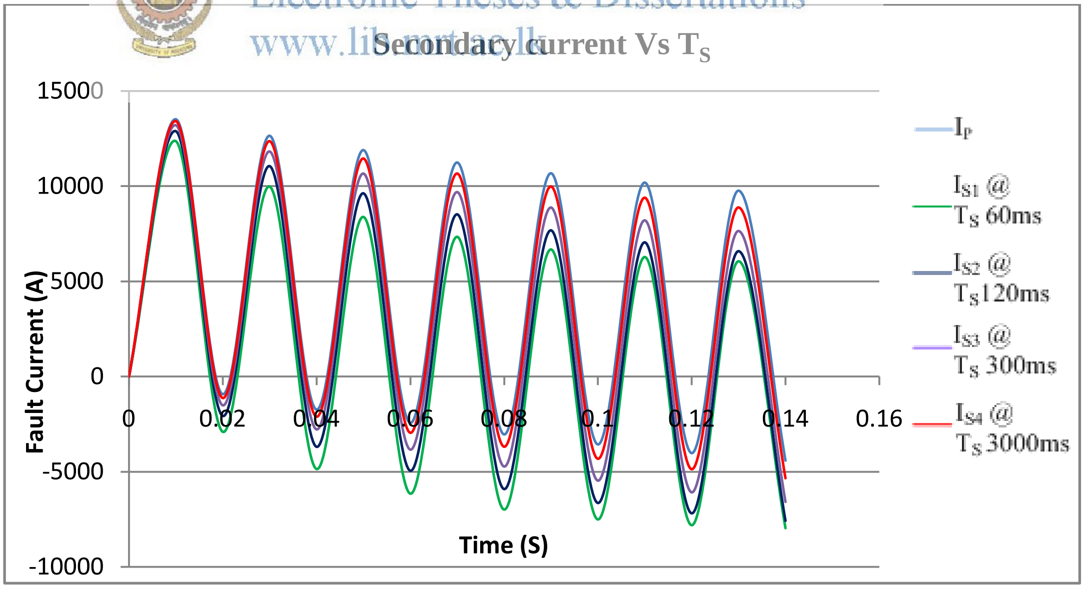

Figure 3-6: Variation of secondary current with secondary time constant

CHAPTER 4

PROTECTION CT CLASSES, THEIR REQUIREMENTS AND A COMPARISON

4.1 Introduction

CTs are divided in to two main classes. These two classes are steady state performance based Protection class (P) CTs and transient performance based transient class (T) CTs. Each CT class has its own unique characteristics and good comparison between each CT class is necessary for optimum CT selection. Requirement of CT class is mainly based on protection function and selected relay type. However proper CT class selection enhances system stability(discussed in detail in chapter 5) In Sri Lanka, still protection engineers are selecting only steady state performance based class P CTs and logical reason or argument behind this limited selection is not quite clear.

4.2 Protection transformer classes

Current transformer classes are categorized on defined error values and on the type of their construction. Composite error is used to define the error classes under steady state conditions. In case of transient state performance, instantaneous values are used to define the error classes. Construction types define the magnetic behavior of the core. Other classifications are based on magnetic characteristic.

4.2.1 Protection transformer – Steady state performance

4.2.1.1 Protection transformer – Class P

These CTs are defined under IEC 60044 and are based on steady state performance. Defined error (Composite error) limit is based only on RMS value of steady state current and performances under transient conditions have not been defined.

As for the type of construction, remnant flux limit has not been defined, but generally it is in the range of around 60% to 80% of saturation flux, which is considered quite high. The limit of saturation is defined on symmetrical fault current.

4.2.1.2 **Protection transformer – Class PR**

Same as class P CTs, the error definitions of these CTs are based on steady state performance and defined errors are same as class P (composite error, ratio error, phase displacement)

There is defined remanent flux limit and practically this is around 10% of saturation flux. Class PR CT core has small air gaps and this causes to high leakage flux and low secondary time constant. This gapped core construction causes low remanent flux level. However, with comparatively closed core, secondary current replica has some distortions.

4.2.1.3 **Protection transformer – Class PX and class PXR**

Class PX

Error definition is based on ratio error and it is defined as ∓ 0.25%.

Protective current transformer has low leakage reactance and it means this CT contains high secondary time constant and no air gaps and hence, no limit for remanent flux and practically it is around 80% of saturation flux. Performance assessment is based on excitation characteristic, secondary winding resistance, secondary burden resistance and turns ratio (Knee point voltage).

Class PXR

The performances of these CTs are defined on same parameter, which is defined on class PX. (Excitation characteristic, secondary winding resistance, secondary burden resistance and turns ratio.)However defined acceptable maximum error limit are different from class PX (ratio error shall not exceed ± 0.25% for class PX and ratio error for class PXR shall not exceed ±1%).

CT has remanent flux limit and practically it is around 10% of saturation flux. Low remanence is maintained by using air gap and at the same time other performance are maintained as class PX. Performance assessment parameters are same as class PX.

4.2.2 Protection CT classes – Based on transient performance

4.2.2.1 **Class TPX**

These CTs are defined based on transient performance, under IEC 60044-6 and IEC 61869-2 and. Defined error limit is based on instantaneous value of error current and it is given as peak value of instantaneous current for the specified duty cycle expressed as a percentage of the peak value of the rated primary short circuit current. In this case, AC and DC instantaneous current components are evaluated to error calculation. In addition to defined transient error, ratio error and phase displacement error limits are defined for evaluating steady state condition.

Transformer construction is closed core and due to very low leakage inductance, no limit for remanent flux (high remanent flux around 80% of saturation level). Due to this construction type, class TPX CTs have very high secondary time constant and these type CTs transform undistorted DC current component to secondary side.

4.2.2.2 **Class TPY**

These CTs are defined under IEC 60044-6 and IEC 61869-2 and based on transient performance .Defined error limit is based on instantaneous error and it is same as class TPX.

Transformer construction is based on gapped core and due to high leakage flux CT has remanent flux limit (Low remanence flux around 10% of saturation level). Due to this construction type, TPY CTs have less secondary time constant (around 300ms is its lower level)

4.2.2.3 **Class TPZ**

These CTs are defined under IEC 60044-6 and IEC 61869-2 and based on transient performance. Defined error limit is based on instantaneous error. In case of error evaluation, instantaneous alternating current component only is considered and instantaneous secondary DC component is not considered.

Transformer construction is based on linear core with larger air gaps and with very low remanent flux. Due to low secondary time constant (around 60ms) DC current component has rapid decaying. Due to low secondary time constant, CT has not followed primary transient current correctly. Lager air gaps cause very rapid demagnetizing; demagnetizing time is around 200ms.

4.3 Comparison of B-H Loop in different type of CT cores

B-H loop describes pattern of flux development in current transformer core with primary current variations. The type of core construction is the main parameter for flux development. Figure 4-1 shows that different types of CT cores maintain different flux levels at same current value. The B-H loop of closed iron core CTs (Class TPX, P) have very high percentage flux at current zero point at CT de – energizing and it is called as remanence flux. Due to anti-remanence air gaps, class TPY and PR CTs have comparative low flux at current zero point. Due to very complex gapped construction, linearized core CTs have very high leakage flux and very low flux level at current zero point.

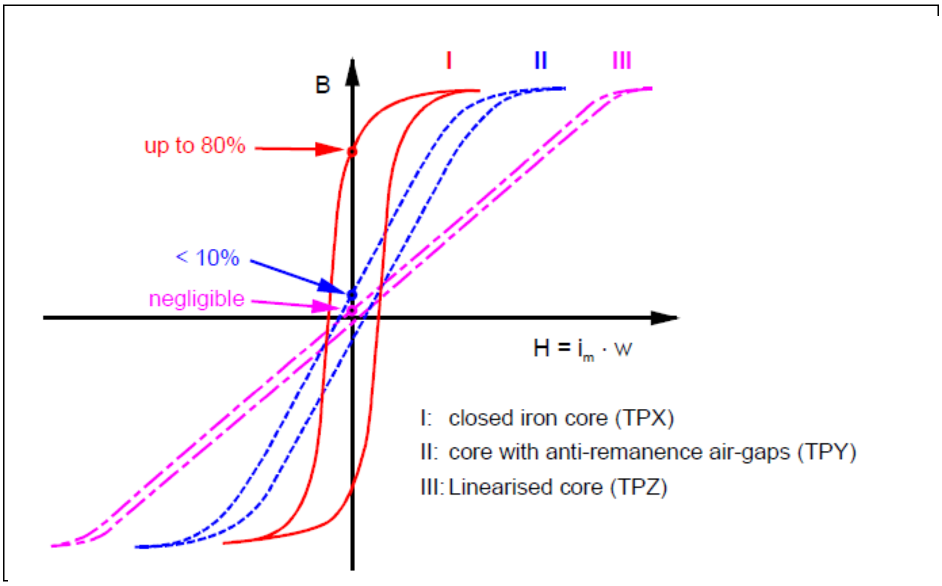

Figure 4-1: BH loop of different type of CT cores

4.4 Comparison between composite error and instantaneous error

4.4.1 Composite error (ε_c)

This defines the error under steady state condition and gives RMS value of the difference between

a) The instantaneous value of primary current (i_p)
b) The instantaneous value of secondary current multiplied by the turns ratio ($K_r i_s$)

The composite error is given by equation (19) [2].

$$\varepsilon_c = \frac{\sqrt{\frac{1}{T}\int_0^T (K_r i_s - i_p)^2 \, dt}}{I_p} \times 100\% \quad \text{............................ (19)}$$

Composite error is given as 5P and 10P for class P and 5PR and 10PR for class PR current transformers.

4.4.2 Instantaneous error current (i_ε)

The instantaneous error current is given as the instantaneous current difference between primary current (i_p) and secondary current multiplied by turns ratio (k_r i_s) [2].

$$i_\varepsilon = k_r i_s - i_p \text{ ………………………………………….. (20)}$$

All DC and AC current components in primary and secondary should be identified separately.

$$i_\varepsilon = i_{\varepsilon ac} + i_{\varepsilon dc} = \left(k_r \times i_{sac} - i_{pac}\right) + (k_r \times i_{sdc} - i_{dc}) \text{ ….. (21)}$$

4.4.2.1 Peak instantaneous error (ε^)

This is peak value of instantaneous error current ($\acute{i}_\varepsilon$) for specified duty cycle and this is expressed as a percentage of the peak value of the rated primary short circuit current [2].

$$\varepsilon\wedge = \frac{\wedge i_\varepsilon}{\sqrt{2} \times I_{Psc}} \times 100\% \text{ ……………………………… (22)}$$

Transient error limit under specified duty cycle conditions are follows

Table 4-1: Error limits of transient class CTs

CT Class	**Peak instantaneous error** (ε^)	**Comment**
TPX	ε^ = 10%	Due to closed core construction, it has very high T_S. DC component takes more than 400ms to decay.
TPY	ε^ = 10%	Due to gaped core construction, it has very low T_S. DC component takes less than 400ms to decay.
TPZ	$\varepsilon\wedge_{ac}$ = 10%	It has very low T_S (around 60ms) and with rapid decaying of DC current component. Therefore, only AC error component is evaluated.

Due to the high secondary time, constant DC current component has high decaying time. Therefore, total error component (AC + DC) is taken to evaluate error value.

Figure 4.2 shows four current waves.

a) Primary current wave at 7kA peak fault current and T_p equals 140ms
b) Unsaturated secondary current wave at 3s secondary time constant (nearly closed core)
c) DC transient current component of primary circuit
d) DC transient current component of secondary circuit

It could be seen that the time taken by the DC components of primary current and secondary currents for complete decaying are 400ms and 200ms respectively. This means that the primary fault current would reach the steady state in around 400ms, and hence up to that limit, no meaningful judgment on the CT performance with the consideration of the steady state based composite error. This time duration varies with network and CT parameters. In comparison, instantaneous error gives a much clearer picture on the CT accuracy performance during the transient period.

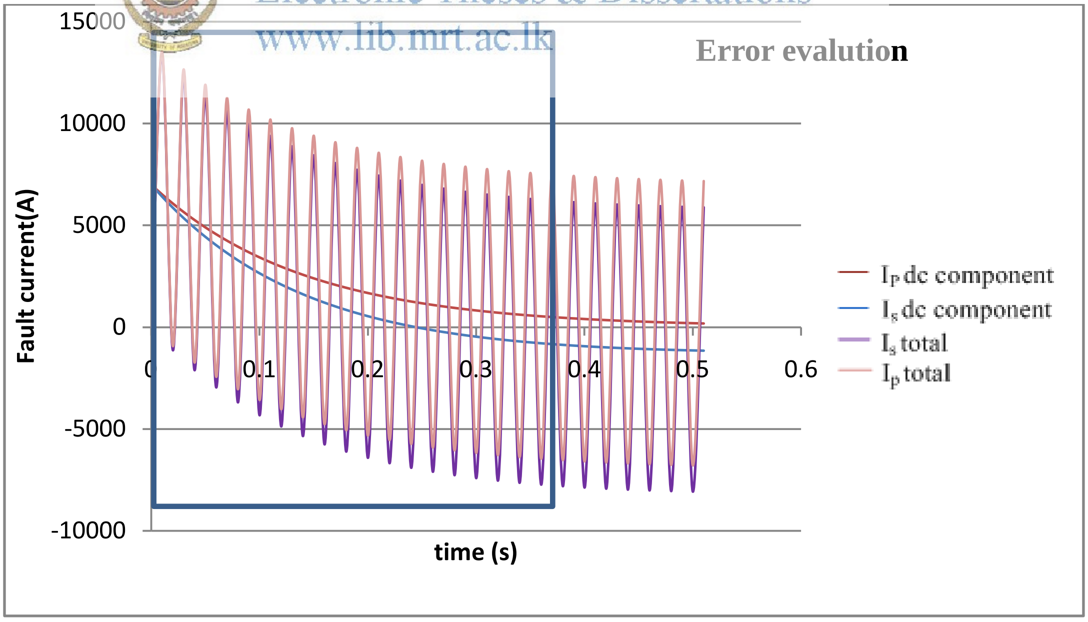

Figure 4-2: DC current components and its decay

4.5 Excitation characteristic of a CT

4.5.1 Under steady state conditions

International standards do not have a common definition for the knee point voltage, though concept behind it is the same. Fundamentally, knee point voltage is the voltage up to which the current transformer secondary terminal voltage maintains linearity with the magnetizing current. Under steady state conditions, IEC uses E_K to denote the knee point [2].

According to the IEC standards, RMS value of the sinusoidal voltage at rated frequency applied to the secondary terminals of the transformer, all other terminals being open circuited, which, when increased by 10% causes the RMS value of the exciting current to increase by 50%, is defined as the knee point.

According to the ANSI, Knee point voltage is defined as the voltage at which the slope is 45^0 with log-log scale.

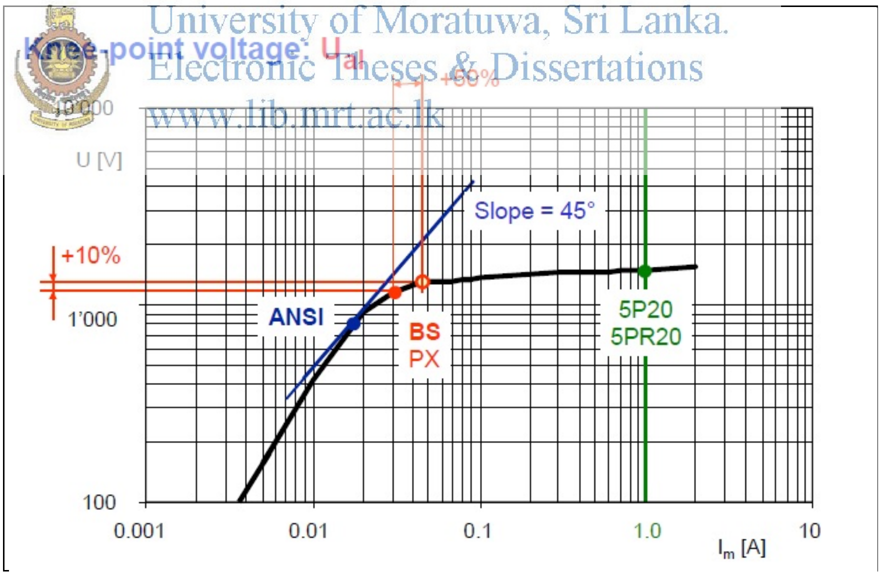

Figure 4-3: Knee point voltage in accordance with ANSI

4.5.2 CT Operation under transient conditions

In the transient state considerations, the term used to denote the above change in the CT characteristic is the rated equivalent secondary e.m.f (E_{al}) [2].

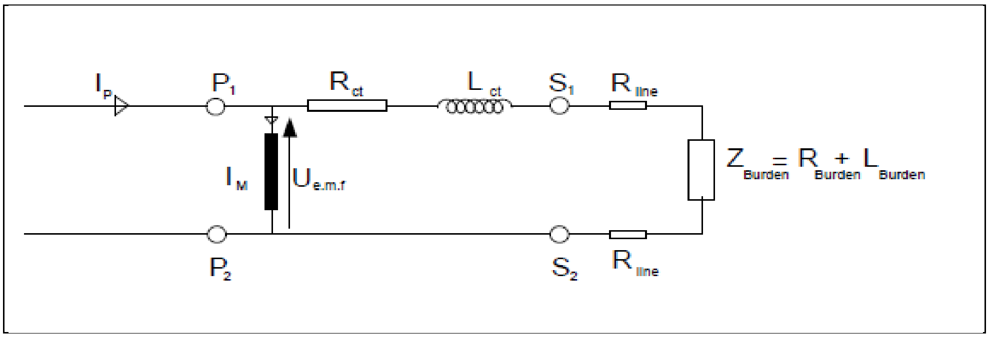

Figure 4-4: Equivalent circuit of a CT with burden

I_P =Primary current

I_{Pn} = Rated Primary current

I_{Fmax} = Maximum symmetrical fault current

I_{sn} = Rated secondary current

I_M = Magnetizing current

$U_{e.m.f}$ =CT internal voltage

R_{ct} =CT secondary winding resistance

L_{ct} = CT secondary leakage inductance

R_{line} = Secondary line Resistance

U_{al} = Required accuracy limiting voltage

Z_b = Burden Impedance

$Z_{ct} = R_{ct} + j\omega L_{ct}$ = CT Impedance

To avoid CT saturation [5] $U_{e.mf} > U_{al}$

$U_{al} \geq (I_{fault\,(max)} / I_{pn}) \times K_{td} \times I_{sn} \times (Z_{ct} + 2\,R_{Line} + Z_{relay})$...................... (23)

U_{al} is a parameter of fault current, transient dimensioning factor and secondary loop impedance. Transient dimensioning factor is sizing parameter of direct current component in the fault current.

High secondary leakage inductance causes low secondary time constant and rapid decaying secondary dc current component. These performances (chapter 3.4 and figure 3.5) make distortion on secondary current replica. Therefore, CT manufacturers tend to maintain minimum leakage inductance. Modern numerical protection relays are with pure resistive burden. However, conventional electromagnetic relays are mainly inductive and it causes an increase in the peak flux in CT core (figure 2.5). In outdoor switchyards, line resistance (R_{line}) is generally large due to long lead wires and hence required accuracy limiting voltage (U_{al}) increases. On the other hand, indoor switch yards (GIS based construction) lead resistance is significantly lower and hence U_{al} is also lower.

According to the closed core CT construction with very low secondary leakage inductance and modern protection relays equation (23) can be modified as follows.

$U_{al} \geq (I_{fault\ (max)} / I_{pn}) \times K_{td} \times I_{sn} \times (R_{ct} + 2\ R_{Line} + R_{relay})$………..….. (24)

Further analysis in PSCAD simulation is presented in chapter (3).

4.6 Accuracy Limit Factor (ALF)

This is defined as ratio of the rated accuracy limit primary current to rated primary current. ALF is defined different ways in different CT classes.

In normal CT protection classes (P10, PR10), ALF is defined as follows [2]

$(I_{psc} / I_{pn}) = K_{ssc}$ ……………………………………..………..…..….. (25)

Where,

I_{PSC} = Rated symmetrical short circuit current

K_{SSC} =Rated symmetrical short circuit current factor

That means in normal protection class CT, the rated ALF is given by $P \times K_{SSC}$ or $PR \times K_{SSC}$.

In transient classes CTs (TPX, TPY, TPZ), ALF will be [2]

$(I_{psc} / I_{pn}) K_{td} = K_{ssc} \times K_{td}$…………………………………………..……. (26)

In transient class CT specification, ALF is given as TPX 20 × 12.5

Where $K_{SSC} = 20$ and $K_{td}=12.5$

4.6.1 **ALF variation with the connected burden**

A current transformer with a given ALF will have an increased ALF if the burden connected is lower than the rated capacity and a decreased ALF if the burden connected is higher than the rated CT capacity.

Considering requirement of accuracy limit voltage [6];

$$ALF_{rated} \times \left(R_{ct}+R_{B(rated)}\right) \geq ALF_{actual} \times (R_{ct}+ R_{B(actual)})$$

$$ALF_{rated} \geq \frac{ALF_{actual} \times \left(R_{ct}+R_{B(actual)}\right)}{\left(R_{ct}+R_{B(rated)}\right)} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (27)$$

$$ALF_{actual} = \frac{I_{SSC(max\ )at\ selected\ location} \times K_{td\ (coordinate\ with\ protection)}}{I_{PN}} \quad \ldots\ldots\ldots\ (28)$$

Rated CT burden = $P_{B(rated)} = P_N = R_{B(rated)} \times I_{SN}^2$

Internal burden of CT = $P_i = R_{ct} \times I_{SN}^2$

Actual connected burden $P_{B(actual)} = R_{B(actual)} \times I_{SN}^2$

$R_{B(actual)} = R_{line}+R_{relay}$

$$ALF_{rated} \geq \frac{ALF_{actual} \times \left(P_i+P_{B(actual)}\right)}{(P_i+P_N)} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (29)$$

Equation (23) and (29) provide sizing criteria, which is based on actual ALF and actual burden.

CHAPTER 5

CURRENT TRANSFORMER SELECTION

5.1 Introduction

Proper selection of CTs is a prerequisite for the efficient and accurate functioning of protection systems. Often, unacceptable operations of protection systems occur due to the wrong selection of CTs. Oversized CTs may facilitate accurate protection operation, but such selections cannot be economically justified. Once optimum selection of CT is done at the planning stage, protection system will operate satisfactorily. However, power system parameters keep on changing with its expansion. Hence, all operators of transmission and distribution systems are required to study and analyze every protection relay operation, and determine the causes of formal operations. In such situations, the operators need to focus on the CT performance as well.

5.2 CT selection criteria

Selection criteria largely hinges on the following main parameters.

1) CT class
2) Core construction
3) Capacity

5.2.1 CT class

CT class selection depends on the following parameters

a) Protection function
b) Type of protection relay
c) Required limit of unit or system stability

5.2.1.1 **Protection functions**

Protection function determines the required delay for relay operation (tripping). Differential protection needs high-speed operation or operation without a delay. The first zone operation of distance protection also needs high-speed fault detection. In the research it has been identified that the categorization of instantaneous, or in other words, tripping without delay is appropriate for the selection of CT class.

The decaying time of DC component and the fault detection time of protection function are the major factors that influence CT class selection. With this information, the maximum CT error that can be permitted within the time duration from the fault inception to that instant, relay makes its decision to operate or not, has to be worked out.

Differential protection

Following are the key features of differential protection that need to be considered in the determination of CT requirements.

a) No time delays involved and the operation is instantaneous. Hence, relay is required to do its fault detection within the first few cycles of the fault, that is, within the transient period.

b) Protection is based on circulating current principle; hence, at any instant, secondary currents from two or more CTs are evaluated to arrive at the tripping decision.

c) To accomplish (b), protection relay needs real time (instantaneous) secondary currents with lower errors than the stipulated levels to determine the primary circuit current differences.

d) Biased curve setting is used to mitigate CT errors.

This curve setting is used to mitigate effects that originate from CT mismatch and network mismatch at through faults. In case of transformer differential protection, transformer magnetizing current component dominates in some extent. The tripping value of differential current of protection relay is set to follow biased curve. However, the relay looks for the instantaneous values of the current.

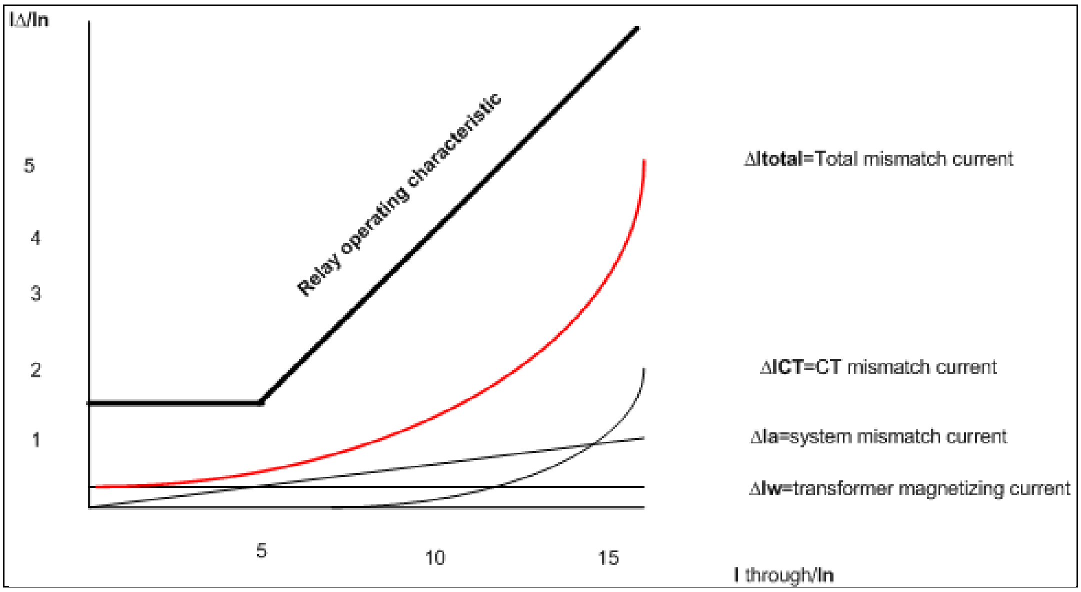

Figure 5-1: Biased characteristic in differential protection

Proper biased curve setting is important for maintaining of system stability. The correct biased curve setting should be based on quantification of error current.

Comparison on the suitability of the steady state and transient state based CTs for differential protection

Table 5-1: Comparison on the suitability of the steady state and transient state based CTs for Differential protection

Feature	CTs based on steady state performance	CTs based on Transient performance
CT errors and circulating current principle (a, b and c)	Composite error is used to specify CT errors, it is defined under steady state conditions, and error is given in rms value (chapter 2). Relay operates before the	The instantaneous error is used for error specification .This gives real time maximum acceptable value, and it can be used for quantification of maximum acceptable error in

	steady state situation is reached and with such error information which given by composite error and proper CTs cannot be selected.	transient condition (chapter 1).
Biased characteristic	The composite error provides RMS value of error in steady state. Hence, with this information, true maximum error value under transient conditions, cannot be computed; therefore, protection engineers are using their field experience or typical values for biased setting with steady state CTs. This field experience and typical values are not making best literature to optimum setting for all time.	The maximum error levels are given in instantaneous values. Therefore, protection engineer can quantify the maximum acceptable current error using specification given by the CT manufacturer under transient conditions. If sufficient information is available, a optimum bias characteristic can be determined and it will enhance the power system stability. Hence, transient class CTs should be the preferred choice for differential protection.

In the case of in - zone faults, protection relay operation has been categorized in to instantaneous operation. However, relay takes time to detect the fault and make tripping decision. This time depends on type of relay and numerical relays are very fast in this process. Static and electro-magnetic relays take more operating time than numerical relays, operating time comparison is given table 5.1. The fastest numerical relay takes nearly 25ms for in - zone fault detections, and it lays in sub transient time zone. According to the system parameters of Sri Lanka and magnetic characteristic of the CTs, saturation starts after half cycle and remains around 400 ms and numerical relays and static relays get there trip decision within this time period (sub transient and transient period).If the CT saturates , first five cycles are a highly saturated period. Hence, transient class CTs are more suitable for in zone fault detection of static and numerical relays.

In case of through faults, protection relay has to look total fault period and this fault duration may exists within sub transient to steady state period and CT must correctly perform in this time zone.

If the protection relay guarantees to relay operation within first half cycle for in-zone faults and if the protection system guarantees to critical fault clearing time less than half cycle for through faults, the application of class P CTs can be accepted.

Distance protection

In order to maintain system stability, any branch of power system afflicted with a fault must be isolated from system within the critical clearing load angle and critical clearing time. The necessity on the part of the relay is to act as fast as possible.

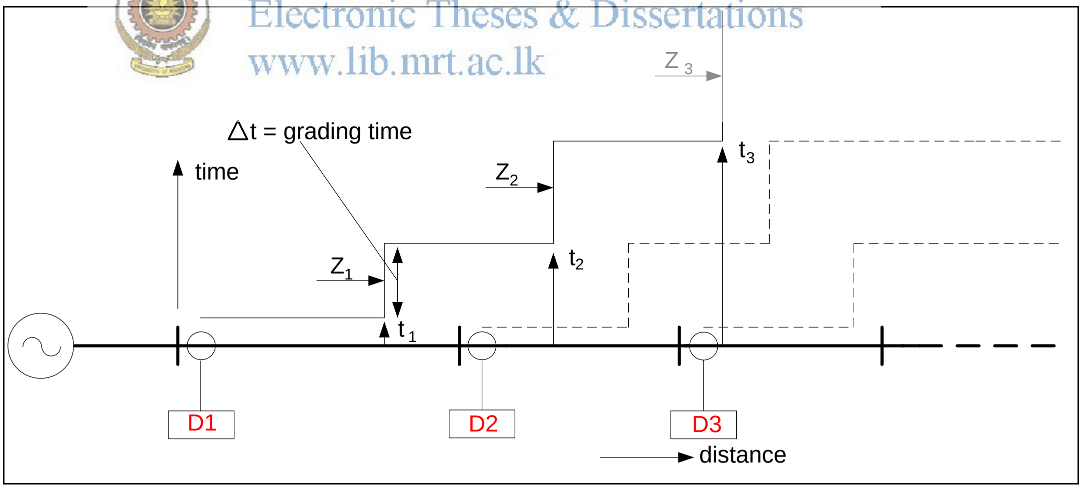

Figure 5-2: Distance relay arrangement

In a distance relay, the first zone operation is instantaneous and it operates within transient period. When secondary current distortions are present due to inaccurate transformation by CTs, the location of the fault as assumed by the relay could differ from the actual location. For a first zone fault close to the boundary between the first zone and second zone, the secondary current distortions might make the relay to imagine it as a second zone fault and hence a delayed tripping.

If this delay exceeds the critical clearing time of this particular location it will cause system instability.

In the power system in Sri Lanka, the maximum primary time constant (T_P) is around 140ms. In a closed core CT construction (this construction consists of possible maximum secondary time constant), the DC current component will take more than 300ms to decay and maximum saturation may occur in the second cycle. Grading time (delay time) in distance schemes is 250-300ms. This implies that the second zone operation also may take place before the complete decay of the DC transient component. Therefore, Transient class is the preferred option for distance protection. As it was discussed in section of differential function (5.2.1.1) the first and second zone operation lie within a region of 10 - 400ms, and the exact operation time varies with type of relay. Therefore, the selection of relay makes high influence to class selection. (Chapter 5.2.1.2)

5.2.1.2 Selection of CT classes - Different types of protection relays

In the distance and differential protections, the type of protection relay plays a vital role in CT class selection. There are three types of protection relays in use in Sri Lanka’s power system, and they are as follows.

a) Electromagnetic (electromechanical) relays
b) Static relays
c) Digital relays
d) Numerical relays

The fault detection time and selectivity varies with type of protection relay and a comparison of differential relay operating times is given in the Table 5.2.

Table 5-2: Comparison of differential relay operating time

Unit	Protection relay	Relay type	Relay operation			Comment
			Phase	Pickup current (mA)	Operating time (ms)	
GT-7 (Kelanitissa Power Station) - 115MW	DTM -7033 CEE France	Static	R	107	263	Relay trip time obeys inverse time curve
			Y	106	228	
			B	109	235	
Sapugaskanda Diesel Generator No 7 - (20 MW)	7UT5131-SIEMENS	Numerical	R	44	46.6	
			Y	44	45.2	
			B	44	44.0	
			RYB	50	39.8	
Puttalam Coal Power station (Norochchola PS) 300MW	DGT801 Guodian Nanjian Auotomation	Numerical	A	3000	25	Relay trip time with inverse proportionality with current, T_{al} is given as 5ms
				750	39	
			B	3000	23	
				750	39	
			C	3000	23	
				750	39	

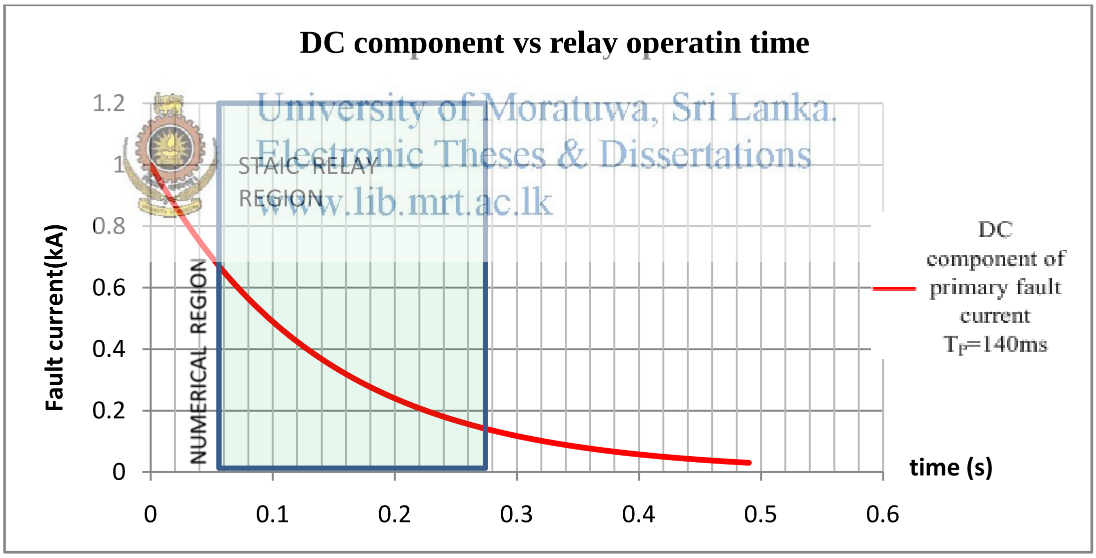

Figure 5-3: Comparison of static and numerical protection relays operation region

5.2.1.3 **Electromagnetic relays**

Electromagnetic relays converts voltage and current signals provided by VTs and CTs in to magnetic and electric forces. These forces are made to interact in a pre-determined manner, and if the resulting forces of such interactions, exceed the restrained forces (determined by relay settings), then the relay activates (mechanical movement), and the activation results in a trip signal. There is an unavoidable time delay of 60ms – 80ms for relay operation.

Electro-mechanical relays operate either as an amplitude comparator or as a phase comparator. Normally these have an operating coil and a restraint coil. In a distance relay, operating coil is fed with the CT and the VT feeds a restraint coil. In a differential relay, both coils are fed by CTs. Therefore, the DC component of the fault current will affect the relay operation, as when the CT saturates, the CT fails to provide an output current and the relevant coils (operating coil and restraint coil) may fail to create magnetic forces required for correct operation. These types of relays have high burdens and are inductive.

Therefore, to ensure satisfactory operation of the electromagnetic relays, following requirements have to be met.

a) CT performance during transient condition has to be correctly specified
b) CT shall operate faithful to its specifications

In accordance with the above, it is not possible to justify the use of Class P type CTs for fast acting electromagnetic relays, as their behavior during the transient period is uncertain. The use of such CTs may often result in mal-operations or delayed operations. However, in case of a protection function with delayed operation such as over current or earth fault protection and where the delay normally exceeds the transient period, then the combination of class P CT and electromagnetic relay can be accepted.

5.2.1.4 **Static relays**

Static relays belong to the next generation of relays after electromagnetic relays. The word “static” implies that these relays have no moving parts. The protection functions are similar to electromagnetic relays and construction in early stages was based on discrete semiconductor electronic elements. In latter stages of their development, microprocessors and linear and digital integrated circuits were used for the relay construction. However, output unit had been an electromagnetic device.

The static relays have comparatively lower operation time and lower burden as compared with electromagnetic relays. Due to the lower burden, required CT cross-section is smaller than electromagnetic relays.

In case of instantaneous protection functions, static relay operates within transient period. Therefore, the CT class requirement is the same as for the electromagnetic relays. CT selector should have clear definition of CTs in transient conditions. That means static relay with transient class CT is a better combination for proper protection configuration [7].

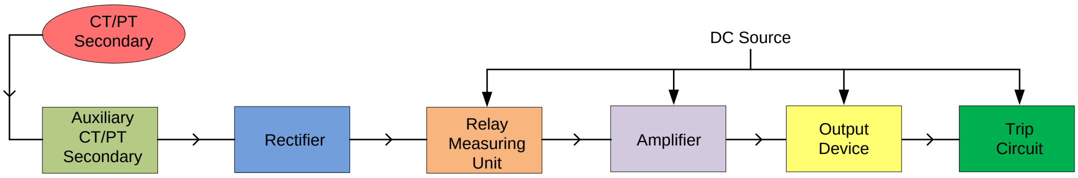

Figure 5-4: Schematic diagram of static relay

5.2.1.5 Numerical relays

Numerical relays are programmable relays. The characteristic, behavior and required logics of the relay can be programmed. In case of input current measuring of relay, the input analogue signals are converted into digital representation (ADC) and processed according to the appropriate mathematical algorithm. In most numerical relays, this algorithm has the capability to detect CT saturation within half cycle period. Due to this feature, numerical relay needs very short saturation free period of CT to perform correct protection function (Chapter 5.2.1.5). Therefore, numerical relay manufacturers are specifying very low CT saturation free time (t_{al}) for particular relay and particular protection function. This very low t_{al} specified by the numerical relay causes dramatic reduction of dimension factor (K_{td}) irrespective of any value of primary time constant and secondary time constant.

Numerical relays have very low burden as less than 0.5VA. This very low burden coupled with very low specified K_{td} cause to large reduction of the required CT size.

Saturation detection of numerical relays

Numerical relays include saturation detectors and they detect saturation very fast and activate additional stabilization. This enhances system stability and this principle is based on wave shape comparison of unsaturated and saturated current waves. According to the saturation detection, relay provides make or block tripping command [8].

Saturation detection in differential protection

In this case, current wave shapes of operating current and restraint current are compared in through faults and internal fault conditions and biased characteristic are adjusted. Wave shape comparison is given by figure 5.5 and following wave shape variations are evaluated by the numerical relay and new adjusted biased curve is given in figure 5.6[8].

a) Relay evaluates CT signals from two defined boundaries.

b) In case of internal fault, resultant restrain current (magnitude addition) component (I_{RES}) follows resultant (vectorial addition) operating current wave (I_{OP}). In first 5ms, no saturation takes place, after first 5ms saturation occurs and both current waves are affected in same pattern.

c) In the case of through faults, after 5ms (saturation free period), due to magnitude addition, restraint current exhibits same wave pattern in internal fault. In 5ms (saturation free period), due to vectorial addition, no resultant operating current in first 5ms and after that there is some resultant current.

d) According to condition a) and b) Numerical relay develops logic flow, which is given in figure 5.7.

e) If relay detects CT saturation after 5ms period, trip signal is delayed by the relay (in this case 150ms).If CT saturates beyond the delayed time, relay will trip. This says if saturation remains after 150ms there is some possibility for unnecessary tripping in through fault conditions and for better stability, due to through faults, if fault remains beyond specified saturation free time (150ms for 7SS5 relay),problem occurs with very low t_{al}. DC current component of secondary current has to be decayed within 150ms or critical fault clearing time must be less than 150ms (150ms specified time by the SIEMENS 7SS5 relay).

f) The above condition says that, importance of correct CT sizing is irrespective of saturation detection of numerical relay.

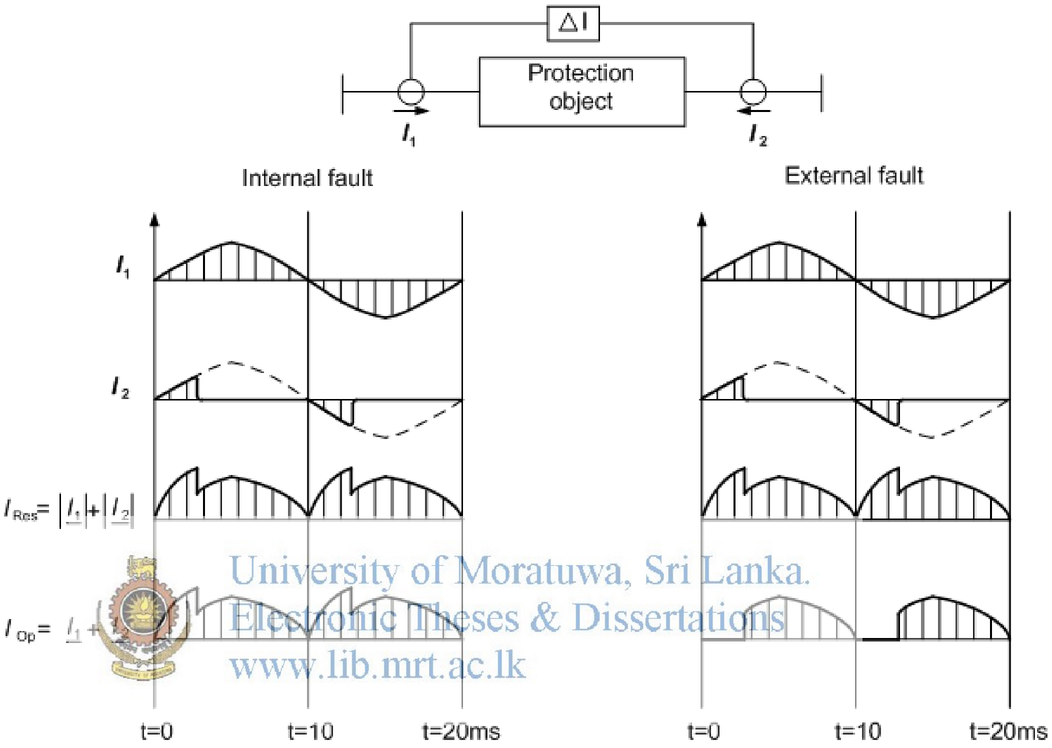

Figure 5-5: CT current wave comparison in differential protection

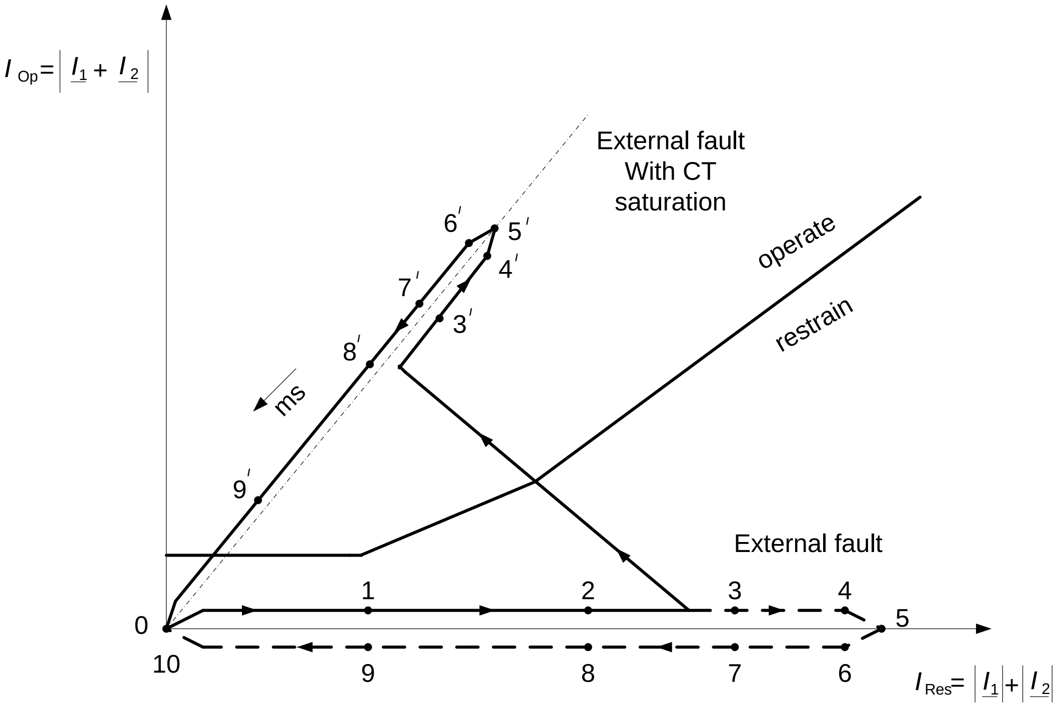

Figure 5-6: Adjusted biased curve

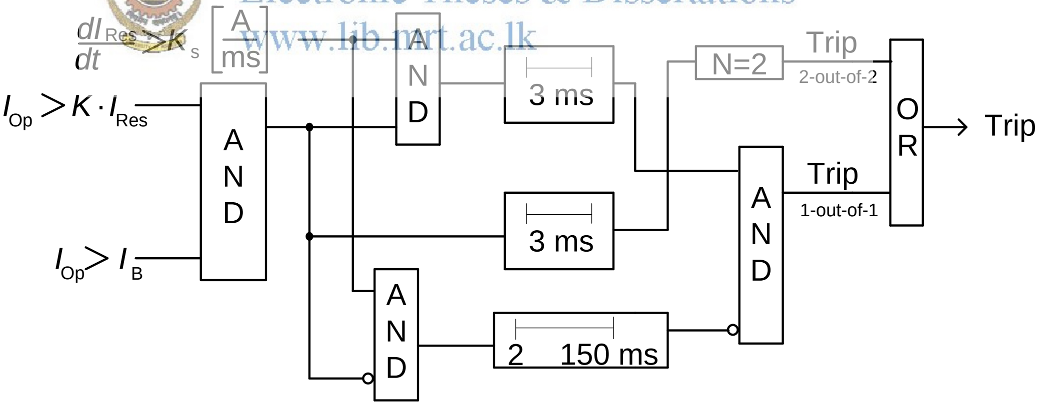

Figure 5-7: Trip logic of numerical relay SIEMENS 7SS5 with saturation detection

Numerical relays with class P CTs

In class P CTs, the composite error definition is for the steady state region and no information is available for sub transient and transient periods. However, as it can be seen from the figure 3.1 in first half cycle, ac flux wave dominates and no saturation takes place. If the required saturation free time for the numerical relay is known and if this time is less than the time in which CT start to saturate (generally this time stays within first half cycle) then class P CT can be used for instantaneous protection functions. However, time for start to saturation varies from CT to CT and fault to fault. However, more instantaneous protection functions involve with delayed supervision. That means, differential protection relay and CT that cater to differential protection must involve to through faults and this through fault period lays through transient period. Same as through faults of differential protection, in distance protection, single CT must cater to instantaneous function and delayed function (first zone and second zone). In selection of class P CT, this phenomenon should be evaluated.

In general, fault detection and decision making done by the numerical relay is within first three cycles and operation time of numerical relay is around 25ms. This fault detection and trip command sending time remains within sub-transient to transient region.

Numerical relays with transient CTs

The transient class CTs has well defined error (Instantaneous error) for sub transient and transient periods. The numerical relay operation takes place within first three cycles and the DC current component dominates within this period, after the first half cycle. If a differential relay is considered, then as the protection engineer is well aware of the limits of errors due to the well defined transient performance of the CT, possible spill current can be worked out and checked with the relay manufacturer’s details for the suitability, calculated relay settings can compare with setting given by relay manufacturer. The fault detection and operating time of numerical differential relay is normally higher than defined saturation free time (T_{al}) required[1]. Hence, the performance of transient class CTs can be trusted during this total transient period. Some reputed protection engineers are hesitating to use transient class CTs and their

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[1] T_{al} is 5ms and instantaneous operating time is 23ms for differential protection of Norochcholei coal power station

argument is based on the size of transient class CT. However, numerical relay manufacturers specify very low T_{al} and hence corresponding K_{td} becomes very low. This implies that the CT size required is also very small. The use of numerical relays with transient CTs for instantaneous protection functions will enhance system stability.

Although cost factor should be considered, it has less importance than the system stability factor.

5.2.2 Core construction

CT properties change with core construction. Core can be with or without air gaps and the latter type is known as closed core CTs. Introduction of gaps into the CTs helps to bring the T_S up to the desired level.

5.2.2.1 Closed core CTs

The closed core CTs are with very low leakage inductances and hence a high secondary time constant. Due to this high secondary time constant, CT core has ability to transform DC current component with high accuracy in a defined range[1]. Closed core CTs have high remnant flux. In general this remanence is more than 80% of it saturation flux level.

Remanence flux makes negative consequences in auto-recloser (ARC) applications. In ARC with circuit breaker operating cycle of C-O-C-O (close – open – close – open), time taken from first ‘open’ to second ‘close’ (duration of the ARC dead time) is effective time for decaying of remanence flux. In the second fault clearing time or time taken to second ‘close’ to second ‘open’ of breaker, core flux develops due to the second fault. However, this flux will build on the remaining flux or remanence flux of first fault. In case of closed core CTs, due to very low leakage flux, the remaining flux level is almost equals to flux at first opening and flux at second fault

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[1] Chapter 2 describes variation of secondary DC current with different secondary time constants.

duration is very high, if ARC dead time is very short. This higher flux level causes core saturation and large core cross section is required to avoid this situation.

5.2.2.2 **Gapped core CTs**

Higher level of gaps causes higher leakage inductance and low T_S. The low T_S reduces the remanent flux levels. However, attempts to achieve very low secondary time constant may affect the secondary current replica. Low T_S ceases DC current component of secondary current wave much faster (Chapter 2). Due to this reason, secondary time constants of class PR, PRX and TPY current transformers are kept within 200-300ms as lower margin. Linear core CTs (TPZ) has large air gaps, hence very low time constants of around 60ms. TPZ CTs are more suitable for shorter ARC dead time applications.

Air gap construction is based on core portioning and this assembly is highly complex. Due to complexity in manufacturing, cost of gapped core CTs is higher than closed core CTs.

Figure 2.2 shows remanence flux variation of different type of cores. This graphical analysis uses following fault detection and clearing times.

t'= Duration of first fault = 120ms

t_{ft} = Fault repetition time or dead time = 250ms

t'' = Duration of second fault = 235ms

As can be seen from the Figure 5.3 TPZ CTs with very low remanence (with rapid decaying) have very low T_s (60ms, linear core construction), and very high remanence have very high T_s (3000ms, closed core construction).

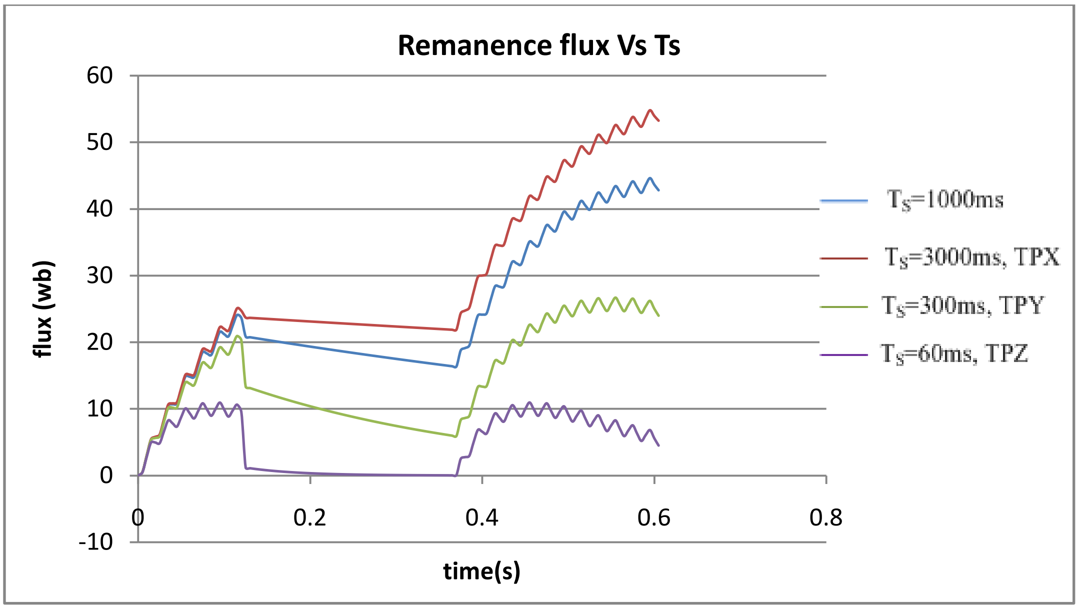

Figure 5-8: Remanence flux variation with secondary time constant

5.2.2.3 **CT core selection**

CT core selection is based on the following.

a) Type of CT installation
b) The value of acceptable K_{td} for any given protection relay
c) Cost of CT

Type of CT installation

CT size is not a major issue in outdoor type CT installation, where generally sufficient space is available for switchgear and installation is based on discrete units. This environment allows using CTs with large cross sections, such as closed core CTs in which remanence flux mitigation takes place.

In the case of indoor substations like Gas Insulated Substations (GIS), the space is an important parameter. In GIS, CTs are encapsulated with circuit breaker and isolator units. Therefore, smaller size CTs are more suitable for GIS. Gapped cores CTs have relatively low cross section. Class TPZ CTs approximately reduces 60% of cross section from closed core CTs and 40% from class PR and class TPX cores.

The value of acceptable K_{td} for a given protection relay

The low K_{td} represents a low cross section for a CT. If the protection relay can operate accurately with lower K_{td}, where accurate DC component transformation is possible, then a closed core CT can be selected.

Cost of CT

As it was discussed in chapter 5.2.2.2 that gapped core construction is complex especially in assembling and fixation. Hence, cost is comparatively high. Therefore, cost factor must be considered with type of switchyard construction.

CHAPTER 6

SELECTION OF OPTIMUM CT SIZE

6.1 Introduction

Theoretical considerations discussed in the preceding chapters and the formulae developed have to be judiciously used to determine the optimum CT sizes for any location.

6.2 Sizing parameters

Optimum CT sizing depends on the following network and protection relay parameters.

a) Maximum possible fault level of the location
b) Primary time constant or network time constant (T_p) at the location
c) Secondary time constant (T_s)
d) Type of selected protection relay
e) Required protection application
f) Burden impedance

Effect of the above parameters on the development of CT core flux were discussed in detail in Chapter 2 and the following have to be computed to specify the CT required for any particular location.

a) The over dimension factor (K_{td})
b) The knee point voltage (or the accuracy limiting e.m.f)
c) The accuracy limit factor (ALF)

6.2.1 Maximum possible fault level of the location

This is directly given by network details or has to be tabulated on available system parameters. However, if any transformer inrush current component is available then, it has to be evaluated.

6.3 Primary time constant or network time constant (T_p) at the location

This is directly given by network details or has to be tabulated on available network parameters. Presently CEB uses primary time constant (T_N) around 110ms.

6.3.1 Secondary time constant (T_S)

This depends on type of CT core. In the case of differential protection, remanence flux is not a factor to be considered. Therefore, closed core CTs can be selected. Secondary time constant of closed core CTs are typically in the range of 1000 - 5000ms.Therefore, the secondary time constant was assumed as 3000ms for the calculation in section 6.3.

In the case of gaped cores, T_S should be justified according to the given permissible error limit. In class TPY CTs, the secondary time constant can be calculated from following formula [1]. This formula gives a relationship of the maximum acceptable instantaneous error with an over dimension factor and a secondary time constant, CT manufacturers give warranty to maximum acceptable error limit and according to IEC standard, it must be less than 10%. Therefore, this formula can be used as reference point of T_S calculation [1].

$$\hat{\varepsilon} \leq \frac{100K_{td}}{2\pi f T_s} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(30)}$$

For TPZ type CTs

$T_S = \frac{10900}{\delta_{minute}}$, Where δ_{minute} = acceptable angle error in minutes [2]

6.3.2 Required saturation free time (T_{al})

This parameter depends on the type of protection relay selected. If the selected relay is numerical, T_{al} is a very low value. In generally it is less than half cycles [8] for Electro-magnetic and static relays.

If the protection relay is static or electro-magnetic, T_{al} must be equal or higher than fault detection time of the protection relay and the relay manufacturer should give detection time. If the fault detection times are not available, T_{al} has to be based on the time taken by the CT to reach the maximum flux level of core. Generally, some CT selectors assume value of T_{al} as infinity (∞). Theoretically, this is not correct and this gives under sized CT for through faults in differential protection. In through faults, if the critical clearing time is larger than T_{al} at maximum flux, this creates a problem and CT acts with under sized characteristic.

In the case of sizing of $T_{al@Bmax}$, IEC 61869-2 standard specifies this value to a pure inductive fault impedance and variable fault inception angle. However, extreme case should be considered in CT sizing. In order to size the maximum the flux, fault inception angle should be zero (0°) with fully inductive fault impedance.

Therefore;

$$T_{al\ @Bmax} = \frac{T_P T_S}{T_S - T_P} l_n \frac{T_S}{T_P} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(31)}$$

This $T_{al\ @Bmax}$ can be used to calculate $K_{td\ max}$ .However this $K_{td\ max}$ greater than K_{td} which specified by given T_{al}.

Sizing of over dimensioning factor (K_{td})

6.3.2.1 T_{al} for numerical relays

The required saturation free time depends on saturation detection algorithm which defined by relay manufacture. However in generally saturation free time ($T_{al} < 10ms$) required by numerical relays is very low. According to the IEC 61869-2 standard this lies in first time zone. If we select K_{td} as 5ms, the graph given by IEC 61869-2 standard can be used for tabulation of K_{td}. This graph has been plotted for a secondary time constant of 1800ms and it lies in the closed core zone. In the application of 3000ms, K_{td} is slightly higher than value given by the graph (graph 1.7 and 1.8).

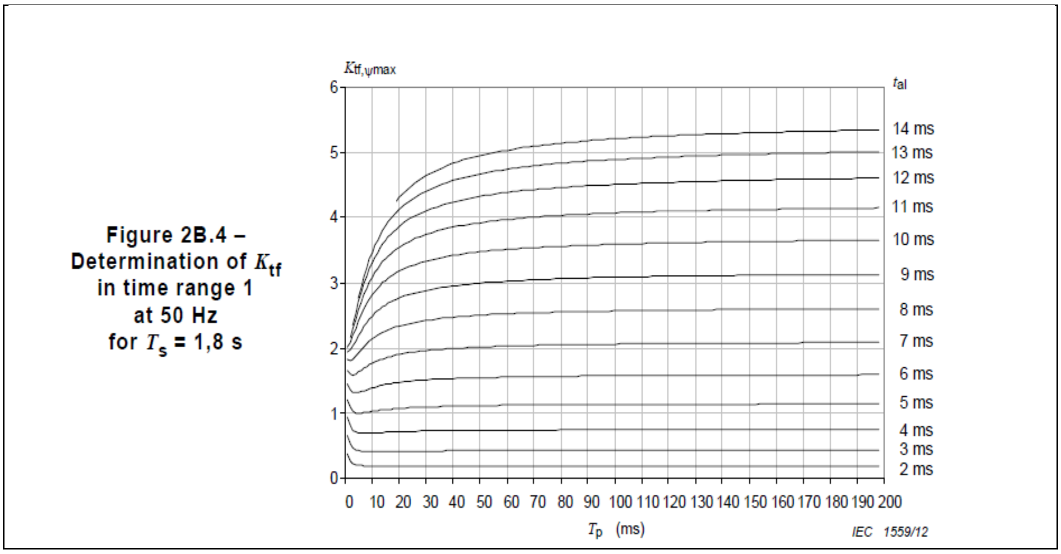

Figure 6-1: Determination of K_{tf} in time zone 1 (IEC 61869-2)

According to the figure 6.1, when T_P is 110ms and T_{al} is 5ms, K_{td} becomes 1.125 (actual value can be seen in the above graph). According to the figure 2.4 (variation of secondary flux with secondary time constant), figure 3.5 (variation of secondary DC current component with secondary time constant) and figure 3.6 (variation of secondary current with secondary time constant), in first half cycle or within first zone of T_{al}, the secondary time constant is not a crucial parameter for sizing of over dimension factor. Therefore, the value tabulated from the above graph can be generalized for gapped core for T_S ranging from 300 ms to 3000ms and closed core CT for T_S ranging from 1000 ms - 5000ms.

6.4 CT sizing for different protection applications

6.4.1 Differential protection relay

This sample calculation is based on Gas Turbine No. 7 of Kelanitissa Power station.

Finding of maximum effective symmetrical fault current at CT location

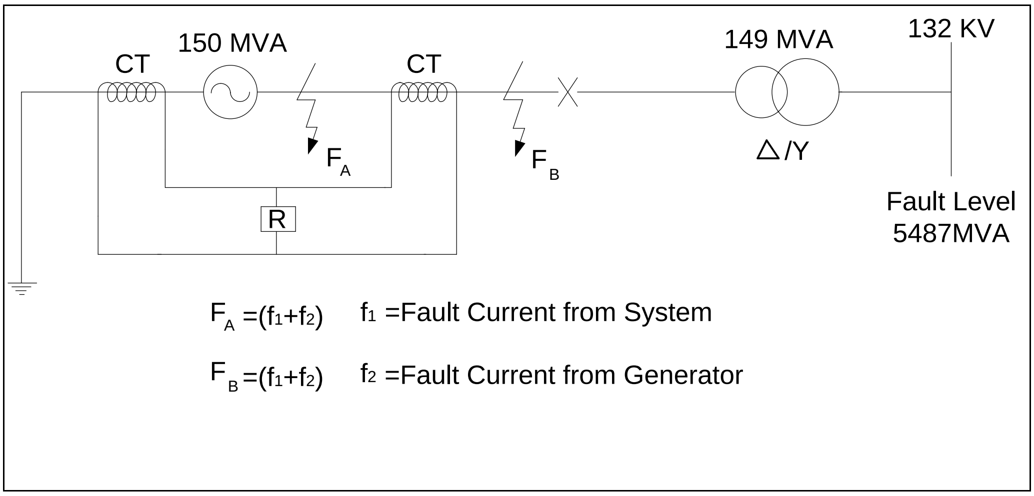

Figure 6-2: Single line diagram of GT7

Table 6-1: Generator and transformer manufacturers' data

Generator		Transformer		Others	
Apparent power	150 MW	Apparent power	149MVA	132kV fault level	5487MVA
Synchronous reactance	180.5%	Transformation ratio	15kV/ 132 kV	CT ratio 11kV	
Sub-transient reactance	13.8%				
Generating voltage	15kV	Vector group	**dY**	CT ratio 132kV	
Generator time constant		Impedance	12%		

Fault level at 132kV bus = 24 kA (Given by transmission branch of CEB)

In the case of faults in protected zone, CTs at outgoing generator terminal, system fault level dominates the CT current.

Network impedance related to 15kV

$$Z_{net} = \frac{kV_{base}{}^{2}}{MVA_{SCC}}$$

$$Z_{net} = \frac{15^2}{5480} = 0.041\Omega$$

Transformer impedance

$$Z_{transformer} = \frac{15^2}{149} \times \frac{12}{100} = 0.181\Omega$$

$$I_{fault\ 1} = \frac{\frac{15}{\sqrt{3}} \times 10^3}{(0.041+0.181)} = 39kA$$

That means network feeds 39kA to protected zone faults through generator terminal CTs.

For neutral terminal CTs,

$$150 \times 10^6 = \sqrt{3} \times V_{L\text{-}base} \times I_{base}$$

$$150 \times 10^6 = \sqrt{3} \times 15 \times 10^3 \times I_{base}$$

$$I_{base} = 5777A$$

$$I_{fault\ 2(p.u)} = \frac{1}{0.138} = 7.248$$

$$I_{fault\ 2} = 7.248 \times 5777 = 41862.31A$$

In the case of through faults, the fault current of 41.86kA affects both the CTs at neutral end and sending end of the generator. Therefore, the case of CT sizing for through fault currents, the fault current component from the network has to be neglected and sizing of ALF and knee point should be based on 41.86 kA. If the CT sizing is based on the total fault current, it may cause over size CT selection for through faults. The maximum possible fault current at the location of the CT does not satisfy the optimum CT selection criteria and it should be corrected as actual maximum possible current that affects CT core. The CT selection of GT 7 shows this argument clearly.

$I_{fault\ (effective)} = 41.86kA$

6.4.1.1 **Determination of primary time constant (T_N)**

T_N is given for the 132kV bus. Therefore, it has to be recalculated for the exact fault location. However, 150MVA generator feeds the maximum fault current to CTs at generator terminals. Therefore, T_N of this current has to be considered for CT sizing and time constant of generator has to be taken for primary time constant.

6.4.1.2 **Determination of secondary time constant (T_S)**

This is determined on core selection. As an initial step, T_S should be checked for closed core construction (closed core CTs provide more distortion free secondary current replica), and if calculated ALF is very high value for closed core CT, and T_S should be selected for gapped core CTs.

6.4.1.3 **K_{td} for electro-magnetic and static relays**

In the case through fault condition of differential protection, as stated earlier, K_{td} has to be calculated by using $T_{al@Bmax}$ or directly by using following formula.

$$K_{td,max}=1+\omega T_S\times\left[\frac{T_P}{T_S}\right]^{\frac{T_S}{T_S-T_N}} \text{ ……………………………………….. (32)}$$

$$K_{td,max}=1+2\times\frac{22}{7}\times50\times3\left[\frac{0.11}{3-0.11}\right]^{\frac{3}{3-0.11}}$$

$K_{td.max} = 31.48$

6.4.1.4 **Selection of CT ratio**

The generator base current is 5777.0 A, therefore the most suitable CT ratio of the existing CT is 7000/1. The higher number of secondary turns causes to increase knee point voltage and level of saturation and at the same time, it causes to increase size of the CT.

6.4.1.5 **Required ALF with numerical relay**

$$ALF_{required} \geq \frac{I_{ssc}}{I_n} \times K_{td(numerical)} \text{ ……………………………………….. (33)}$$

$$ALF_{required} \geq \frac{41862}{7000} \times 1.25$$

$$ALF_{required} \geq 7.47$$

6.4.1.6 **Required ALF with static relay**

$$ALF_{required} \geq \frac{I_{SSC}}{I_n} \times K_{td(static)} \text{ ………………………………………... (33)}$$

$$ALF_{required} \geq \frac{41862}{7000} \times 14.4$$

$$ALF_{required} \geq 86.1$$

6.4.2 **Bus bar differential protection**

In CT sizing of bus bar differential protection, the fault current contribution of each feeder has to consider. Each feeder has its own primary time constant, and the total equivalent time constant at the fault location can be calculated using following formula.

If having N number of feeders available with fault currents of $I_1, I_2, I_3, \ldots\ldots I_N$ and relevant primary time constants of $T_1, T_2, T_3 \ldots\ldots T_N$. The equation [9] (34) gives equivalent total primary time constant at the fault location.

$$T_{p\,(equivalent)} = \frac{I_1T_1 + I_2T_2 + I_3T_3 \ldots\ldots I_NT_N}{I_1 + I_2 + I_3 \ldots\ldots I_N} \text{ ……………………………..…… (34)}$$

The selection of T_{al} depends on selected protection relay type for bus bar differential protection.

6.4.3 CT sizing for distance protection

As discussed under differential protection, the relay type arises as one of the main sizing criteria. In addition to that, type of application (with or without ARC), the level of remanence, and the type of installation (CT core) arise as other main factors of CT sizing. The fault calculation is the same as in differential protection.

Without ARC application

In this application, the remanence flux is not considered in CT sizing. In the first protection zone of relay operation, CT sizing is very similar to CT sizing done in differential protection. The type of protection relay makes high influences in CT sizing. If the protection relay is numerical, CT sizing is based on required CT saturation free time specified by the relay manufacture. If this time is within 1st time zone for over dimensioning factor (K_{td}) sizing, (less than 10ms or calculated value by formula $T_{al\,1} = \frac{\pi+\varphi}{\omega}$) K_{td} has to be calculated using graphs given by IEC 61869-2 standard. If the relay is electromagnetic or static, generally T_{al} is higher than 25ms or within second time zone for K_{td} sizing.

Network parameters such as fault level and primary time constant, and CT core parameter such as the secondary time constant should be taken as in the method applied in differential protection.

K_{td} is given by following equation for second time zone, and without ARC application [2].

$$K_{td} = \left(\frac{T_p T_s \omega}{(T_s - T_p)} \left(e^{\frac{-t}{T_s}} - e^{\frac{-t}{T_p}} \right) + 1 \right) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(35)}$$

With ARC application

In ARC application, the remanence flux makes a high level of influence on CT sizing for distance protection. In case of CT sizing, following time periods have to be defined clearly (flux development in CT core due remanence flux is discussed in chapter of CT core selection).

a) Fault detection time of relay
b) Time for Circuit breaker opening after fault detection
c) Time for first opening to second closing (Dead time - t_{DT})
d) Time for second fault detection (t_{F2})

Time for the first fault detection and time for circuit breaker opening after fault detection can be added as duration of the first fault (t_{F1}). The core flux development after the second fault detection has not dominated in CT sizing; therefore, the time after the second fault detection to the second breaker opening can be neglected. According to the above parameters, the general equation of K_{td} for ARC application is given bellow [9].

$$K_{td} = \left[1+\frac{\omega T_N T_S}{T_N-T_S}\left(e^{\frac{t_{F1}}{T_N}}-e^{\frac{t_{F1}}{T_S}}\right)\right] e^{\frac{t_{DT}+t_{F2}}{T_S}} + \left[1+\frac{\omega T_N T_S}{T_N-T_S}\left(e^{\frac{t_{F2}}{T_N}}-e^{\frac{t_{F2}}{T_S}}\right)\right] \text{………...….. (36)}$$

The general equation says exponential decaying of flux in the dead time (t_{DT}). In the case of closed core CTs, due to negligible leakage inductance the flux decaying in dead time (t_{DT}) is very small and $T_S \gg T_N$. Therefore the CT core flux after the first fault duration almost equals the core flux in the CT just before the second closing of circuit breaker. This is graphically analyzed in chapter of core selection (5.2.2.3). Hence general equation can be simplified for closed core CT applications as given bellow [9].

$$K_{td} = \left[1+\frac{\omega T_N T_S}{T_N-T_S}\left(e^{\frac{t_{F1}}{T_N}}-e^{\frac{t_{F1}}{T_S}}\right)\right] + \left[1+\frac{\omega T_N T_S}{T_N-T_S}\left(e^{\frac{t_{F2}}{T_N}}-e^{\frac{t_{F2}}{T_S}}\right)\right] \text{………....…….. (37)}$$

$$K_{td} = \left[1+\omega T_N\left(1-e^{\frac{t_{F1}}{T_N}}\right)\right] + \left[1+\omega T_N\left(1-e^{\frac{t_{F2}}{T_N}}\right)\right] \text{……….......…………. (38)}$$

Numerical relay and K_{td} for ARC application

According to the above general equation of total K_{td} is based on summation two subsets of K_{td}.

K_{td1} = Over dimensioning factor for the first fault duration and dead time.

K_{td2} = Over dimensioning factor for the second fault duration or the second fault detection.

Then general equation can be rearranged as follows.

$$K_{td}= K_{td1}+K_{td2} \text{ ………......…………………………………………. (39)}$$

$$K_{td} = \left[1+\frac{\omega T_N T_S}{T_N-T_S}\left(e^{\frac{t_{F1}}{T_N}}-e^{\frac{t_{F1}}{T_S}}\right)\right]+[K_{td2}] \text{……….......……………………. (40)}$$

In the case of numerical relays with close in faults (fault location is very close to zone staring point), according to the software algorithm (ability to saturation detection) and type tests that the relay manufacturer has given value for K_{td2}. If this value equals to ‘a’, we can rearrange K_{td} sizing equation as follows.

$$K_{td}=\left[1+\frac{\omega T_N T_S}{T_N-T_S}\left(e^{\frac{t_{F1}}{T_N}}-e^{\frac{t_{F1}}{T_S}}\right)\right]+[a] \text{……….......…………………….…. (41)}$$

In general, the relay manufacturer do not give K_{td1} directly and it has to be calculated from the total first fault duration (fault detection time + breaker opening time) because the flux development due to the total first fault duration affects final core flux development in the CT.

Remanence factor (K_{Rem})

Considering the remanence effect, remanence factor has to be included in the final over dimensioning factor and the final over dimensioning factor has to be rearranged as follows[9].

$$K_{td(final)} = K_{Rem}\times K_{td} \text{ ………..…………. (42)}$$

$$K_{Rem} = \frac{1}{1-\frac{\%\ \text{remanence}}{100}} \text{ ……….......………………………...………. (43)}$$

Typical values of remanence

CT type	Level of remanence
Closed core CTs (class P, class TPX)	> 80%
Gapped core CTs (class PR, class TPY)	10%
Linear core CTs (class TPZ)	Negligible

6.5 Sample calculation - 220kV GIS Kelanitissa

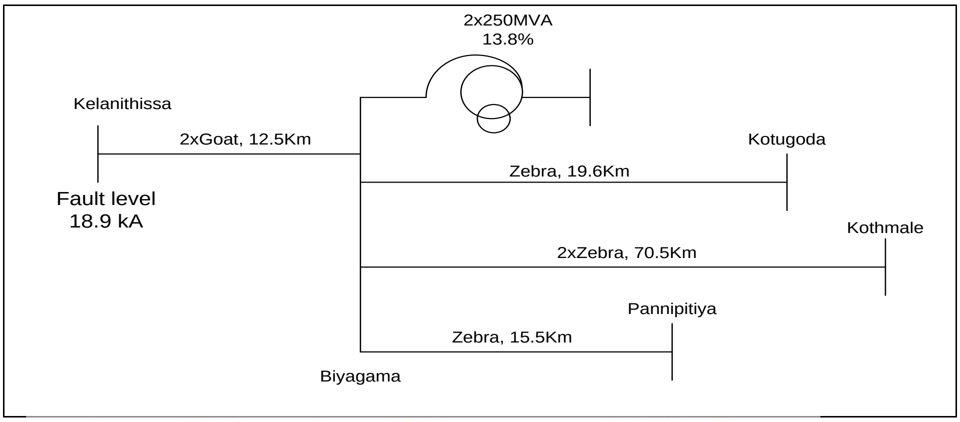

Figure 6-3: Switchyard arrangement of 220kV GIS Kelanitissa

6.5.1 Line parameters

Table 6-2: Line parameters

1	Line	Kelanitissa - Biyagama
2	Conductor type	2× goat
3	Line length	12.5 km
4	Fault level at Kelanitissa	18.9 kA
5	Impedance per km	0.052 + 0.296 j
6	Total impedance	0.650 + 3.7 j
7	Line mutual impedance	0.26575 + 0.6677 j
8	Total mutual impedance	3.321875 + 8.346875 j
9	Primary time constant at Kelantissa	110ms
10	Maximum transmittable power	495 MVA

6.5.2 Sizing for closed core CTs

6.5.2.1 Calculation of over dimension factor for close in fault with ARC application

Condition 1, for closed core applications

Use following equation for closed core CTs application,

$$K_{td} = \left[1+\omega T_N(1-e^{-\frac{t_{F1}}{T_N}})\right] + \left[1+\omega T_N\left(1-e^{-\frac{t_{F2}}{T_N}}\right)\right] \ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(44)}$$

T_N = 110 ms (Network parameter)

$T_{F1} = T_M$ (fault detection time) + Breaker operating time

50ms (second half cycles) is taken as the breaker operating time, and this is guaranteed by the breaker manufacturer and condition monitoring tests. In the case of T_m , relay setting is zero (0 ms) (instantaneous operation). However, it depends on type of relay. SIPROTECH (Siemens numerical relay) relays are selected for this application and T_M is justified as 25ms.

T_{F1} = 25ms + 50ms = 75 ms

In the case of T_{F2}, only fault detection time is considered for CT sizing.

T_{F2} = 25ms

The relay has not given over- dimension factor for the first fault duration and relay given over dimension value for second fault duration is not taken for calculation.

$$K_{td}=\left[1+\frac{44}{7}\times 50\times 0.110\times(1-e^{-\frac{75}{110}})\right] + \left[1+\frac{44}{7}\times 50\times 0.110\times\left(1-e^{-\frac{25}{110}}\right)\right]$$

K_{td}= 26.29

$$I_{base} = \frac{495\times 10^6}{\surd 3\times 220\times 10^3} = 1299A$$

Due to value of I_{base} select 2500/1 CT for sizing.

$$ALF_{actual} = \frac{18900}{2500} \times 26.9$$

$$ALF_{actual} = \frac{18900}{2500} \times 26.9$$

$$ALF_{actual} = 193.68$$

$$ALF_{rated} \geq \frac{ALF_{actual} \times \left(R_{ct} + R_{B(actual)}\right)}{\left(R_{ct} + R_{B(rated)}\right)} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(23)}$$

$$ALF_{rated} \geq \frac{ALF_{actual} \times \left(P_i + P_{B(actual)}\right)}{(P_i + P_N)} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(34)}$$

Standard rated ALF values are 20, 30 and so on.

According to the above equations of (23) and (25) the high ALF $_{actual}$ has to be compensated by very low ratio of $\frac{\left(P_i + P_{B(actual)}\right)}{(P_i + P_N)}$. Value of 30VA can be justified rated burden and 6VA can be justified as the CT internal burden. However, CT sizing, the above two parameters has to be specified by the CT selector according to the protection requirement.

CT installation in GIS systems, 2.5mm^2 cross-sectioned and 5m twin copper cable is selected.

A numerical relay gives very low burden.

Cable resistance $R = \frac{\rho l}{A} = \frac{0.0179 \times 10}{2.5} = 0.0176\Omega$

$$ALF_{rated} \geq \frac{193.68 \times (6 + 0.5716)}{(6 + 30)}$$

$$ALF_{rated} \geq 35.34$$

Check for required knee point voltage

$$U_{al} \geq \left(I_{fault\ (max)} / I_{pn} \right) \times K_{td} \times I_{sn} \times \left(R_{ct} + 2\ R_{Line} + R_{relay} \right)$$

$$U_{al} \geq \frac{18900}{2500} \times 26.2\ 9 \times 1 \times (6 + 0.5716)$$

$$U_{al} \geq 1306.12$$

The calculated actual burden is higher than the standard rated burdens. Therefore, the CT ratio of 2500/1 is not suitable. Hence, recalculate for 4000/1 ratio.

$$\mathrm{ALF}_{\mathrm{actual}}= \frac{18900}{4000}\times 26.9=121.05$$

$$\mathrm{ALF}_{\mathrm{rated}} \geq \frac{121.05\times(6+0.5716)}{(6+30)}$$

$$\mathrm{ALF}_{\mathrm{rated}} \geq 22.09$$

$$U_{al} \geq \frac{18900}{4000}\times 22.09\times 1\times(6 + 0.5716)$$

$$U_{al} \geq 685.91\mathrm{V}$$

This value is within the standard ALF (30), however CT size is much larger than 2500/1.

Considering over dimension factor (a) recommended by numerical relay for the second fault duration.

$$K_{td} = \left[1+\omega T_N\left(1-e^{-\frac{t_{F1}}{T_N}}\right)\right] + a \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (45)$$

$$K_{td} = \left[1+\frac{44}{7}\times 50\times 0.110\times\left(1-e^{-\frac{75}{110}}\right)\right] +2$$

$$K_{td} = 18.08+2=20.08$$

$$\mathrm{ALF}_{\mathrm{actual}}= \frac{18900}{2500}\times 20.08=144.58$$

$$\mathrm{ALF}_{\mathrm{rated}} \geq \frac{144.58\times(6+0.5716)}{(6+30)}$$

$$\mathrm{ALF}_{\mathrm{rated}} \geq 26.39$$

$$U_{al} \geq \frac{18900}{2500}\times 20.08\times 1\times (6+0.5716)$$

$$U_{al} \geq 997.60\mathrm{V}$$

This means that a closed core can be used with numerical relay. Then class TPX can be recommended with the numerical relay.

Condition 2, CT sizing for gapped core

Assumption for secondary time constant

The practical range of the secondary time constant will be between 300ms to 3s. However, this value must be followed in the error limit specified by equation (46).

$$\hat{\varepsilon} \leq \frac{100K_{td}}{2\pi f T_s} \text{ ……………………………………………………….…… (46)}$$

Assume $T_S = 3$ s

$T_P = 110$ms (system data)

$T_{F1} = 75$ ms, $T_{F2} = 25$ ms

$T_{DT} = 400$ ms

Use general equation for K_{td} (not considering relay type)

$$K_{td} = \left[1+\frac{\omega T_N T_S}{T_N-T_S}\left(e^{-\frac{t_{F1}}{T_N}}-e^{-\frac{t_{F1}}{T_S}}\right)\right] e^{-\frac{t_{DT}+t_{F2}}{T_S}} + \left[1+\frac{\omega T_N T_S}{T_N-T_S}\left(e^{-\frac{t_{F2}}{T_N}}-e^{-\frac{t_{F2}}{T_S}}\right)\right] \text{……… (47)}$$

$$K_{td} = \left[1+\frac{314.285\times 0.110\times 3\times}{0.110-3}\left(e^{-\frac{75}{110}}-e^{-\frac{0.075}{3}}\right)\right] e^{-\frac{.425}{3}} + \left[1+\frac{314.285\times 0.110\times 3\times}{0.110-3}\left(e^{-\frac{25}{110}}-e^{-\frac{0.025}{3}}\right)\right]$$

$K_{td} = 26.3$

However, K_{td} and T_S must within error limits and recalculate T_S according to the error limit

$$\hat{\varepsilon} \leq \frac{100K_{td}}{2\pi f T_s} \text{……………………………………………………..……. (46)}$$

$$T_S \leq \frac{100\times 26.3}{314.285\times 10}$$

$T_S \leq 0.836$

According to the new secondary time constant, recalculate K_{td}.

Take $T_S = 0.8$ s

$$K_{td}=\left[1+\frac{314.285\times0.110\times0.8\times}{0.110-0.8}(e^{-\frac{75}{110}}-e^{-\frac{0.075}{0.8}})\right]e^{-\frac{.425}{0.8}}+\left[1+\frac{314.285\times0.110\times0.8\times}{0.110-0.8}\left(e^{-\frac{25}{110}}-e^{-\frac{0.025}{0.8}}\right)\right]$$

$K_{td} = 21.222$

$ALF_{actual} = \frac{18900}{2500}\times21.222=160.43$

$ALF_{rated} \geq \frac{160.438\times(6+0.5716)}{(6+30)}$

$ALF_{rated} \geq 29.28$

$U_{al} \geq \frac{18900}{2500}\times21.222\times1\times(6+0.5716)$

$U_{al} \geq 1053.33V$

The total K_{td} for numerical relay is given as saturation free time or over dimension factor.

$$K_{td}=\left[1+\frac{\omega T_N T_S}{T_N-T_S}(e^{-\frac{t_{F1}}{T_N}}-e^{-\frac{t_{F1}}{T_S}})\right]e^{-\frac{t_{DT}+t_{F2}}{T_S}}+a \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(48)}$$

a = 2 (Given by protection relay)

$$K_{td} = \left[1+\frac{314.285\times0.110\times0.8\times}{0.110-0.8}(e^{-\frac{75}{110}}-e^{-\frac{0.075}{0.8}})\right]e^{-\frac{.425}{0.8}}+2$$

$K_{td} = 19.2$

$ALF_{actual} = \frac{18900}{2500}\times19.2=145.15$

$ALF_{rated} \geq \frac{145.152\times(6+0.5716)}{(6+30)}$

$ALF_{rated} \geq 26.5$

$U_{al} \geq \frac{18900}{2500}\times19.2\times1\times(6+0.5716)$

$U_{al} \geq 953.89V$

6.5.2.2 **Fault in zone limit with ARC application**

Step 1: Finding source impedance or network impedance up to 220 kV bus (X_S)

Assumption - $x_s \approx z_s$ (source equivalent resistance is negligible)

$$X_S = \frac{V_L}{\sqrt{3}\times I_{SC}} \frac{220\times10^3}{\sqrt{3}\times18.9\times10^3} = 6.72\Omega$$

$$T_N = \frac{L_S}{R_S} = \frac{X_S/\omega}{R_S} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(49)}$$

$$R_S = \frac{X_S}{\omega\times T_N} = \frac{6.72}{314.285\times0.110} = 0.19$$

Considered zone limit is 85% from line length, transmission line is double circuit and mutual impedance is considered to fault calculation.

$R_{LT(Line+mutual)}$ = (0.650+3.322)×0.85 = 3.37

$X_{LT(Line+mutual)}$ = (3.70+8.35)×0.85 = 10.24

Total impedance at balance point

$Z_{balance\ point}$ = (3.37+0.19)+(6.72+10.24)j = 3.56+16.96j

Fault current at balance point

$$I_{SC(balance\ point)} = \frac{V_L/\sqrt{3}}{Z_{balance\ point}} = \frac{127.01\times10^3}{17.32} = 7.33\text{kA}$$

Primary time constant, T_N at balance point

$$T_N = \frac{(X_S+X_L)/\omega}{R_S+R_L} = \frac{0.053}{3.56} = 15\text{ms}$$

For closed core application

T_{F1} = 75 ms, T_{F2} = 25 ms (relay parameters and breaker parameters remaining as above)

T_N = 15ms

$$K_{td} = \left[1+\omega T_N(1-e^{-\frac{t_{F1}}{T_N}})\right] + \left[1+\omega T_N\left(1-e^{-\frac{t_{F2}}{T_N}}\right)\right] \text{ ……………………...…. } (44)$$

$$K_{td} = \left[1+\frac{44}{7}\times 50\times 0.015\times(1-e^{-\frac{75}{15}})\right] + \left[1+\frac{44}{7}\times 50\times 0.015\times\left(1-e^{-\frac{25}{15}}\right)\right]$$

$K_{td} = 10.49$

$$ALF_{actual} = \frac{7330}{2500}\times 10.49 = 30.75$$

$$ALF_{rated} \geq \frac{30.75\times(6+0.5716)}{(6+30)}$$

$ALF_{rated} \geq 5.61$

$ALF_{actual(at\ close\ in\ fault)} > ALF_{actual\ (at\ close\ in\ fault)}$

$$U_{al} \geq \frac{18900}{2500}\times 10.49\times 1\times (6+0.5716)$$

$U_{al} \geq 521.16V$

CT must be sized to higher ALF $_{actual}$. In this case we have to size the CT for close in faults condition.

Gapped core application

The relay parameters, breaker parameters and secondary time constant are the same as above.

T_{F1} = 75 ms, T_{F2} = 25 ms (relay parameters and breaker parameters remaining as above)

T_N = 15ms, T_S = 0.8s

$$K_{td}=\left[1+\frac{314.285\times 0.015\times 0.8\times}{0.015-0.8}(e^{-\frac{75}{15}}-e^{-\frac{0.075}{0.8}})\right]e^{-\frac{.425}{0.8}}+\left[1+\frac{314.285\times 0.015\times 0.8\times}{0.015-0.8}\left(e^{-\frac{25}{15}}-e^{-\frac{0.025}{0.8}}\right)\right]$$

$K_{td}=8.48$

$$ALF_{actual}=\frac{7330}{2500}\times 8.48=24.86$$

$ALF_{rated} \geq \frac{24.86\times(6+0.5716)}{(6+30)}$

$ALF_{rated} \geq 4.53$

$U_{al} \geq \frac{18900}{2500}\times 8.48\times 1\times (6+0.5716)$

$U_{al} \geq 421.30V$

6.5.2.3 **Size comparison between closed core and gaped core CTs**

$K_{td\ (closed\ core)} = 26.29$ (Over dimension factor for closed core, saturation free time given by numerical relay is not considered.)

$K_{td(gapped\ core)c} = 21.222$ (Over dimension factor for gapped core, saturation free time given by numerical relay is not considered.)

Core cross section reduction

$$= \frac{K_{td(closed\ core)}-K_{td(gapped\ core)}}{K_{td(closed\ core)}}\times 100 = \frac{26.29-21.22}{26.29}\times 100 = 19.28\%$$

This size reduction depends on value of K_{td}.

According to the above calculation, gapped cored (class TPY) ratio of 2500/1 and ALF_{rated} of 30 is better CT option for 220kV KPS – Biyagama line at the GIS end.

Sizing of linear core CT (class TPZ)

In the case of linear core CT, due to the very high leakage flux the low secondary time constant, there is no requirement for CT sizing for remanence flux. This shows in the figure 5.8 (remanence flux variation with secondary time constant). Saturation free time (T_{al}) has to be taken as time for maximum flux development in CT core. K_{td} has to be size for the maximum flux.

General equation is given below;

$$K_{td} = 1+\omega T_S\times\left[\frac{T_N}{T_S}\right]^{\frac{T_S}{T_S-T_N}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (50)$$

However, the CT has to comply following error limit.

$$T_S = \frac{10900}{\delta_{minute}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(51)}$$

$\delta_{minute} = 180 \pm 18$ minute (acceptable error limit given by IEC)

Acceptable T_S = 61ms (Derived from error limit)

T_N = 110 ms (given by system data)

$$K_{td} = 1+314.285\times0.061\times\left[\frac{110}{61}\right]^{\frac{61}{61-110}}$$

$$K_{td} = 9.20$$

Size comparison between closed core and linear core CTs.

$$\text{Core cross section reduction} = \frac{K_{td(\text{closed core})}-K_{td(\text{linear core})}}{K_{td(\text{closed core})}}\times100 = \frac{26.29-9.20}{26.29}\times100 = 65.00\%$$

6.6 CT size comparison with and without numerical relay

6.6.1 Case 1: Closed core

K_{td} = 26.29 (Over -dimension factor of closed core without considering relay type)

K_{td} = 20.08 (Over- dimension factor of closed core with numerical relay)

Cross section reduction

$$= \frac{K_{td(\text{without numerical relay})}-K_{td(\text{with numerical relay})}}{K_{td(\text{without numerical})}}\times100 = \frac{26.29-20.08}{26.29}\times100 = 23.62\%$$

6.6.2 Case 2: Gapped core

K_{td} = 21.222 (Over- dimension factor of gapped core without considering relay type)

K_{td} = 19.2 (Over- dimension factor of gapped core with numerical relay)

Cross section reduction

$$= \frac{K_{td(\text{without numerical relay})} - K_{td(\text{with numerical relay})}}{K_{td(\text{without numerical})}} \times 100 = \frac{21.222-19.2}{19.2} \times 100 = 9.52\%$$

The above analysis means that the combination of closed core and numerical relay provides almost the same reduction of cross section with the combination of conventional relay and gapped core CTs. In the case of conventional protection relays, due to the requirement of high saturation free time (T_{al}), it dominates sizing of K_{td} than the low secondary time constant of gapped core. The recommended optimum selection for the GIS systems is numerical relay with gapped core CT.

CHAPTER 7

CASE STUDY

This case study is based on a mal-operation of protection in Wimalasurendra Power Station (WPS). WPS is one of most crucial link in the cascaded Laxapana hydropower complex. WPS consists of two 20MW generators and both generators feed 132kV bus bar through 30MVA step up transformers.

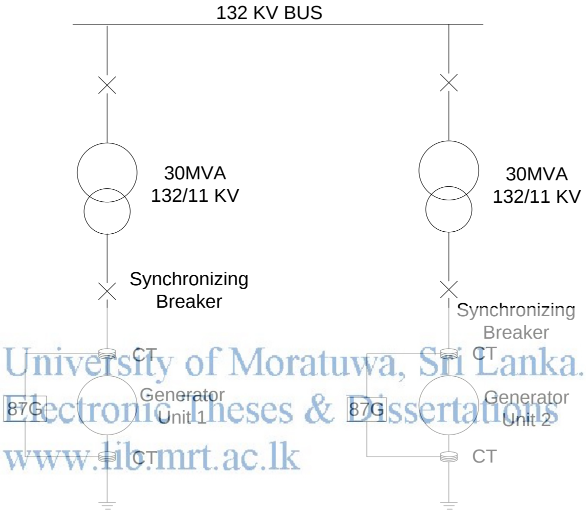

Figure 7-1: Wimalasurendra generator arrangement

7.1 Events of incident

1. Generator unit-1 tripped due to the operation of protection relay 87G on 15.12.2012 at 08.30hrs.When the generator tripped; it was running at a load of 20 MW.
2. When unit-2 transformer was energized, the unit-1 generator tripped. In normal operation practice two generators units feed to common 132kV bus bar through 30MVA transformers.
3. Data was taken from disturbance recorder (F731) and it was analyzed.

4. It was also found that generator neutral side CTs were saturated during transformer energization.
5. Faults records were taken from digital fault recorder (Ben32).
6. It was also observed and confirmed that this is due to the saturation of generator differential protection CTs.
7. Same type of faults occurred to unit-2 generators on 10th, 21st and 29th of November 2012 when unit-01 transformer was energized.

7.2 Conclusion and discussion

1. It was observed that there was a DC component in the transformer energization current (inrush current).
2. It was also observed that there was an abnormal sequence in three phases as recorded by the fault recorder (Ben 32).
    a) It was identified that the polarity of wiring from phase B of the CT to the fault recorder (Ben 32) had been changed.
    b) The polarity was corrected and sequence error of the fault recorder (Ben-2) was corrected.
3. Possible reasons of this mal-operation.
    a) Inadequate CT size.
    b) Higher line impedance with comparative transformer impedance.
    Typically, it should be less than 10% of transformer impedance. Due to high line impedance, unit-01 generator acted as the main source of transformer unit two energization, and it contributed a high current with comparative current component of the line side for transformer energization current. However, this current component has to be quantified and if this current component is higher than maximum fault current which affects the CT, and sizing of the CT must be based on highest current.
    c) This transformer energization current is not a fault current. Therefore critical clearing time not affect saturation limiting and it highly depends on magnitude and decaying time of dc current component of transformer energization current. As it was discussed in chapter 5.2.1.5 , in case of

through faults (high current condition), relay analyzes the CT secondary wave forms and avoids from tripping command for pre determined (specified by the relay) time. If the CT saturation exists longer beyond this period, the relay gives tripping command. This says that relay gives guarantee for stability in through faults within only defined time, which is given by protection relay. If the transformer energization current causes to CT saturation beyond this period, it may cause to this unwanted tripping.

d) The abnormal magnetic characteristics of transformer causes very large decaying time of DC component of transformer energization current and very long CT saturation time.

4. This protection mal-operation has not occurred in every transformer energization, and has occurred occasionally. That shows the relationship with the inception angle and the magnitude of DC current component.

7.2.1 Inadequate CT size

CT size has to be calculated with network parameters compared with existing CT parameters.

7.2.1.1 Existing CT data

Table 7-1: Existing CT data

1	Rated primary current	2000A
2	Rated secondary current	5A
3	Class	5P
4	ALF	10
5	Rated burden	30VA (At cos∅ = 0.8)
6	Applied standard	60044-1
7	Manufacture	DELLE
8	T_S	Not specified (closed core)

7.3 Problems that have to be answered

1. Numerical relay (REG316*4) is used for 87G protection. Therefore, following problems have arisen.
   a) What is the required saturation free time for protection relay? Or else, what is the value for K_{td} recommended for the relay?
   b) What is the limit of relay used it saturation detection capability?
   c) What is the limit of critical clearing time involvement?

REG316*4 Numerical relay has not given clearly defined values for required saturation free time or K_{td} and it has given effective ALF (n') by the equation (52) for differential protection (RE216/316 CT requirements – application notes – 1KHA001038Aen Edition August 2008).

$$n' = 1.2(\mathbf{2\pi f_n T_N+1}) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(52)},\ n' \geq 20$$

According to the basic equations of K_{td}, highlighted part of the above equation equals to K_{td} at infinite saturation free time with closed core CT. That means REG316*4 defines K_{td} beyond 5ms or first time zone defined by IEC 61869 standard. According to the comparison with fundamental equation, the ratio of maximum possible fault current and rated current has been restricted to 1.2 or final n' should equal or greater than 20.

Fundamental equation for effective ALF,

$$n' \geq \frac{I_{SC\text{-}Max}}{I_n} K_{td} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(53)}$$

According to the above equation, n' should maintain with limit of fault current or size of CT and not with relay parameters.

However, ALF of existing CT has not fulfilled requirement of protection relay (REG316*4). ALF of existing CT equals to 10 (7.2.1.1- existing CT data) and protection relay required ALF of 20.

2. In the case of two or more generators are feeding through separate power transformers to single high voltage bus, how should it cater to transformer energization current in CT sizing.

It is very clear that the transformer energization current is not a fault current, and it contains a DC component and second harmonic component. The CT has to cater for this DC component in the total duration of decaying. If the protection relay consists of second harmonic detection and trip command blocking for an appropriate period, then CT sizing has to be based on possible maximum fault current. This particular feature is normally included in transformer differential protection. However, in the case of similar arrangement of WPS, if harmonic detection is enabled in generator differential protection, stability will be increased.

3. If we select transient class CT for application, what would be the final performance?

This is discussed in chapter 5.

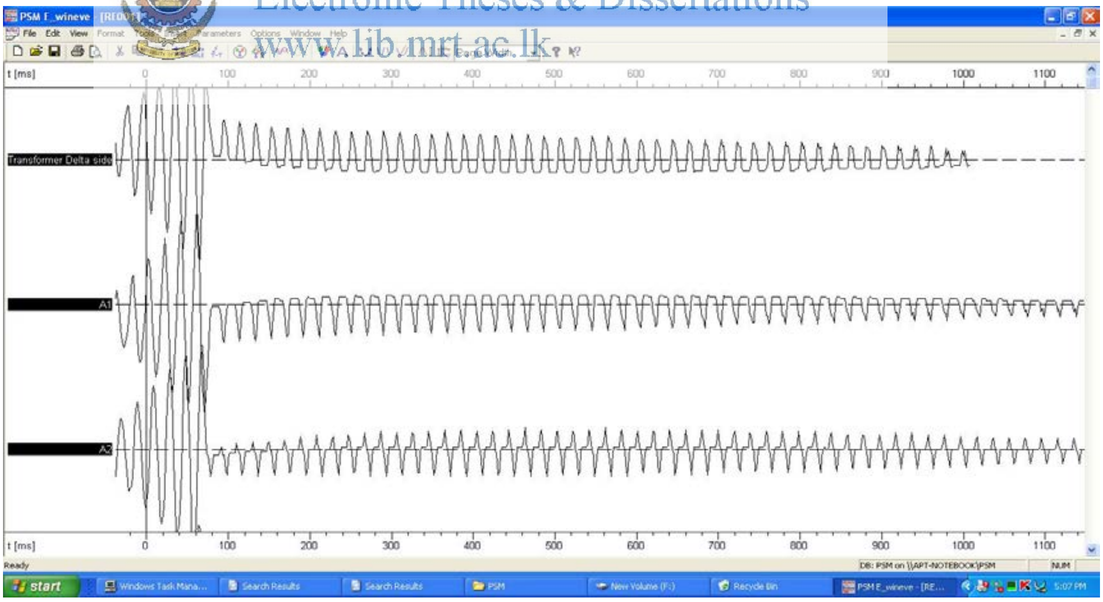

Figure 7-2: Disturbance records from protection relay (REG316*4)

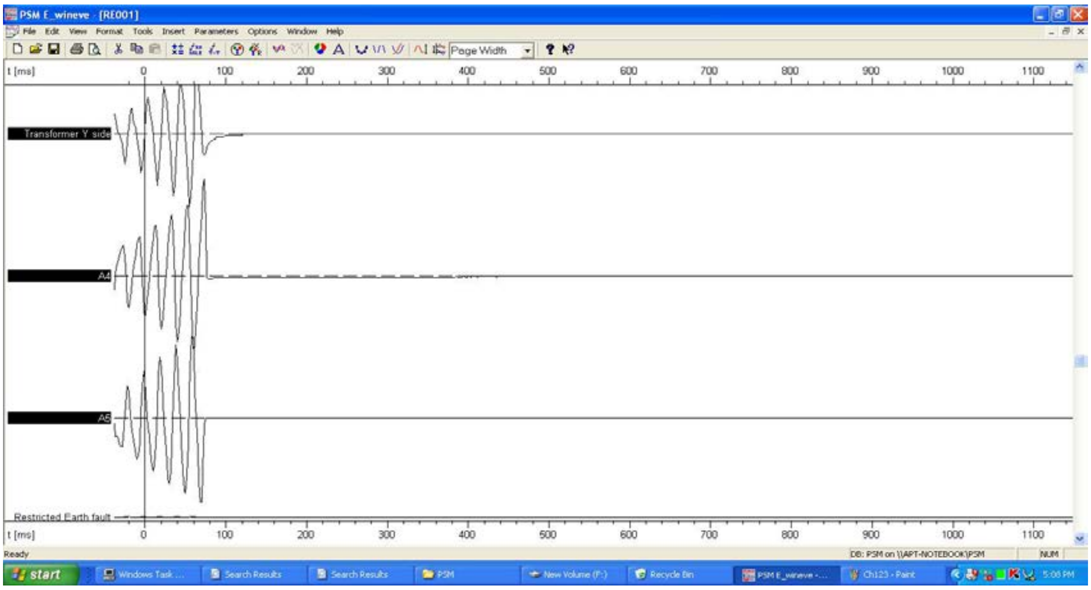

Figure 7-3: Disturbance records from protection relay (REG316*4)

CHAPTER 8

DEVELOPMENT OF CT SELECTION CRITERIA

8.1 Network and CT parameters based CT selection criteria

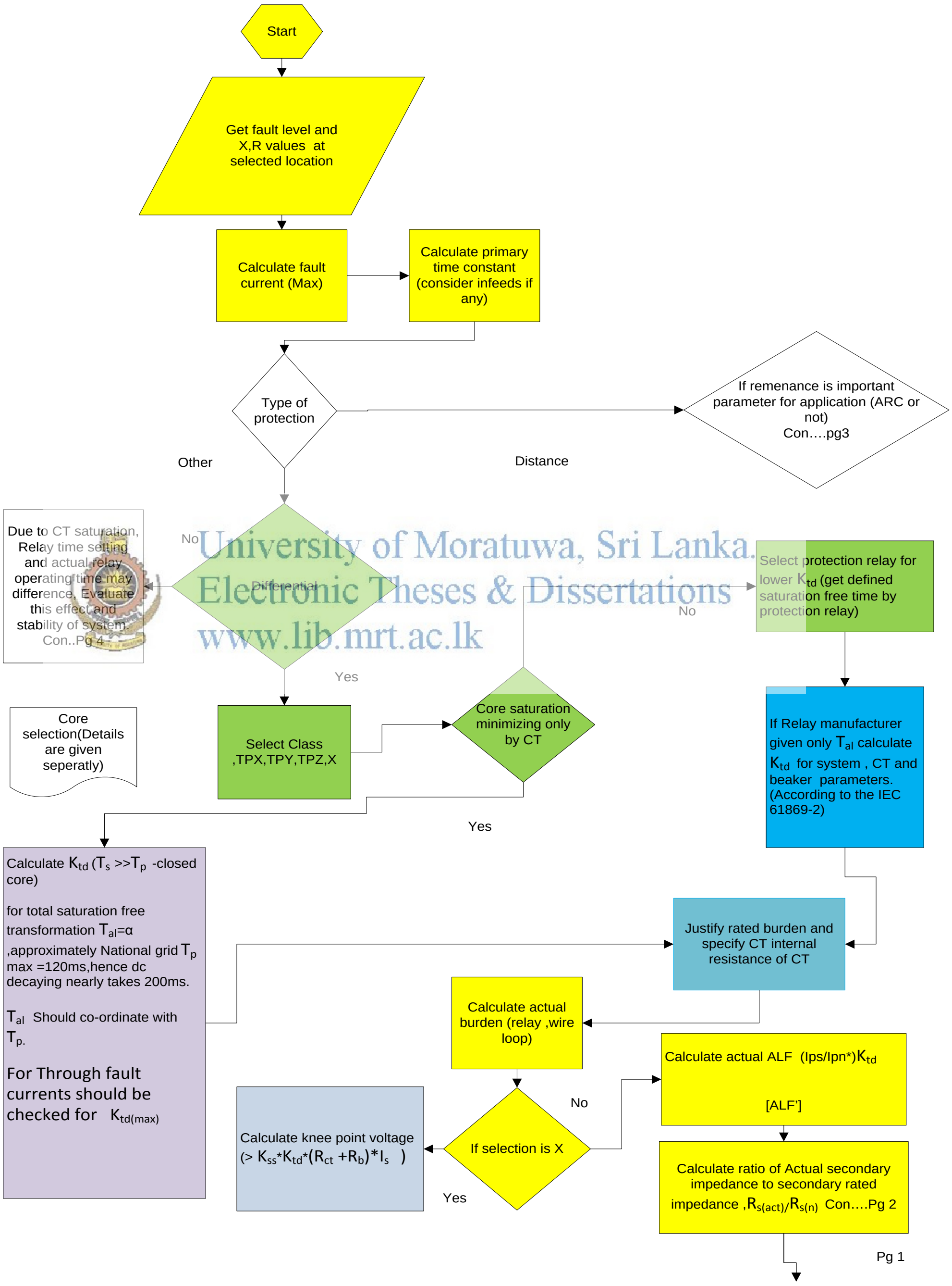

Figure 8-1: Network and CT parameters based CT selection criteria-Page 1

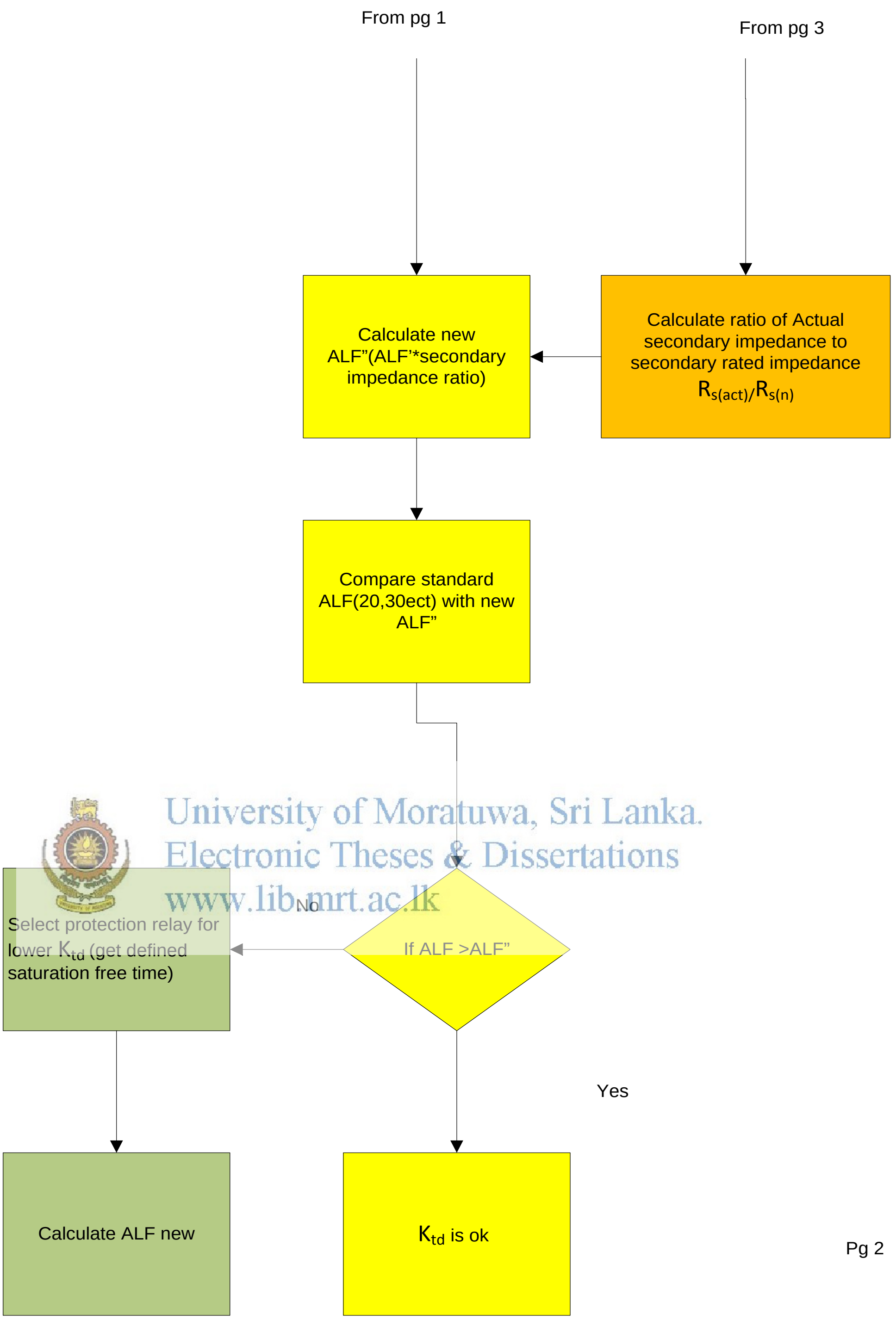

Figure 8-2: Network and CT parameters based CT selection criteria-Page 2

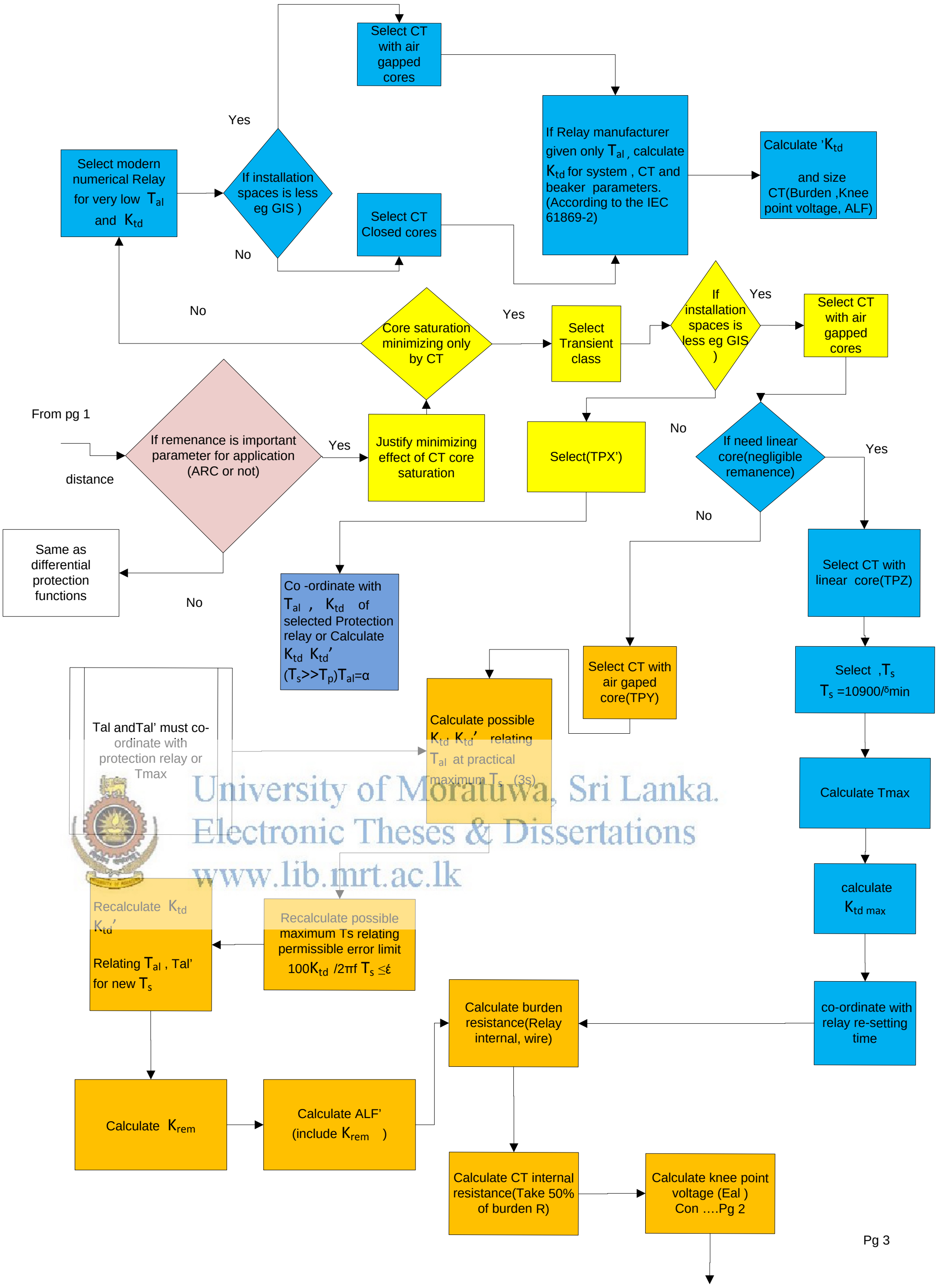

Figure 8-3: Network and CT parameters based CT selection criteria-Page 3

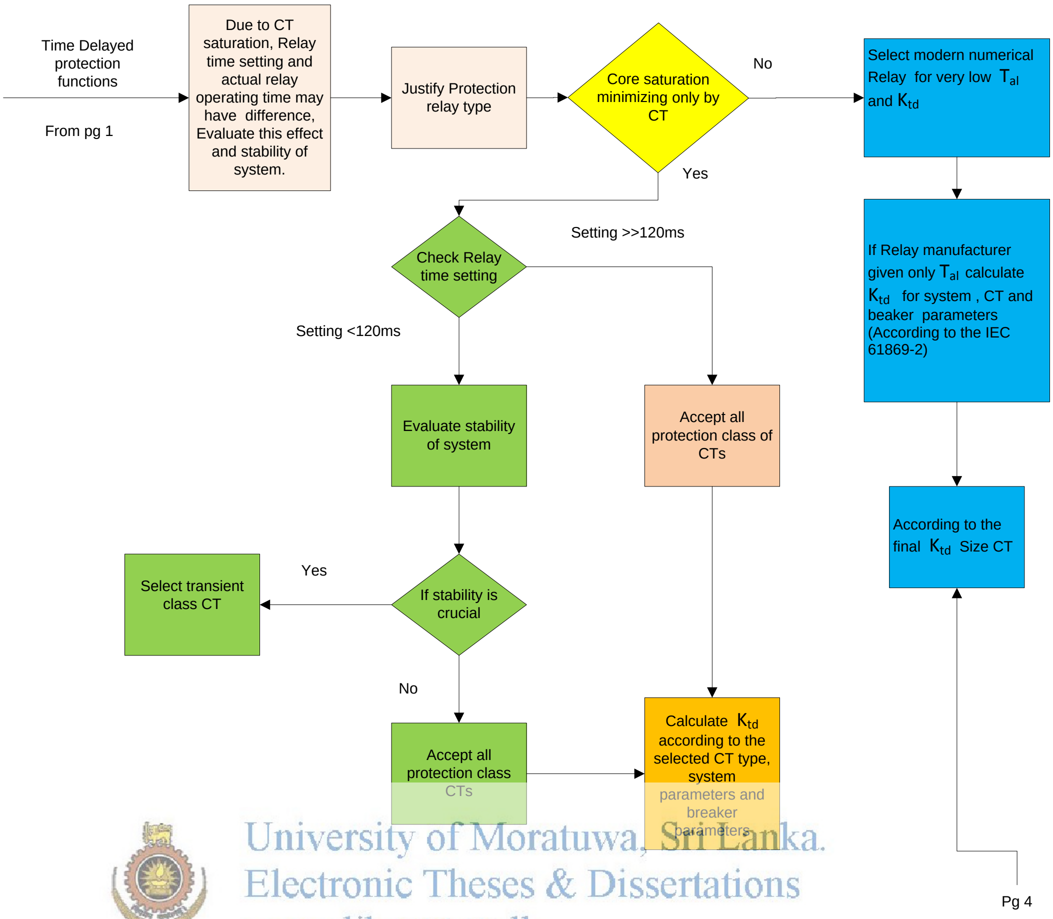

Figure 8-4: Network and CT parameters based CT selection criteria-Page 4

8.2 Relay based CT selection

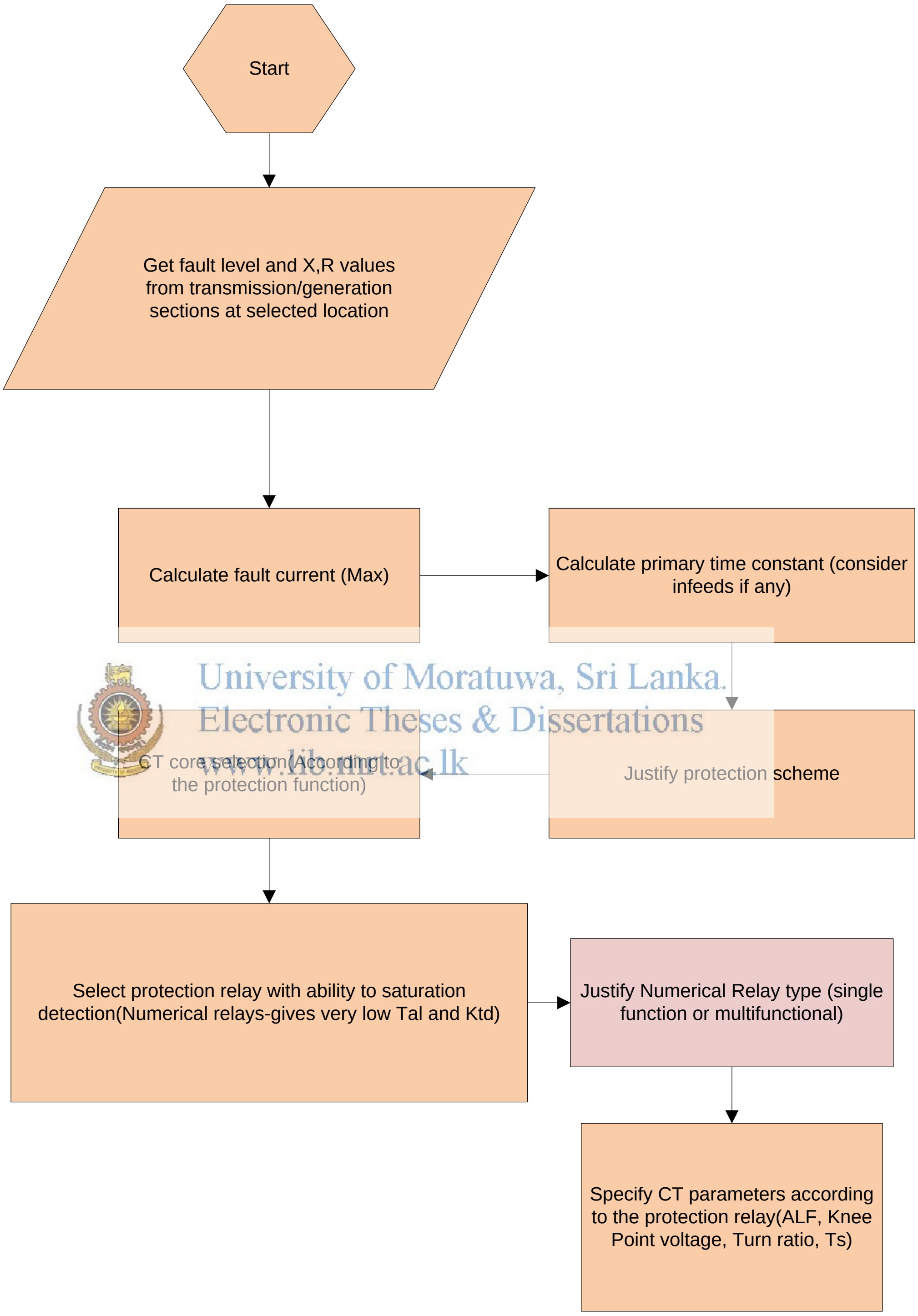

Figure 8-5: Relay based CT selection

CHAPTER 9

PSCAD SIMULATION

This model is included with two 300MVA, 13.8kV generators are connected parallel through 350MVA, 13.8/132kV, delta/star transformers, and these two generators feed to star connected 50MW and 15MVAR load.

Three phase symmetrical fault is simulated at 132kV bus bar terminals. The current transformer JA model is used for simulation.

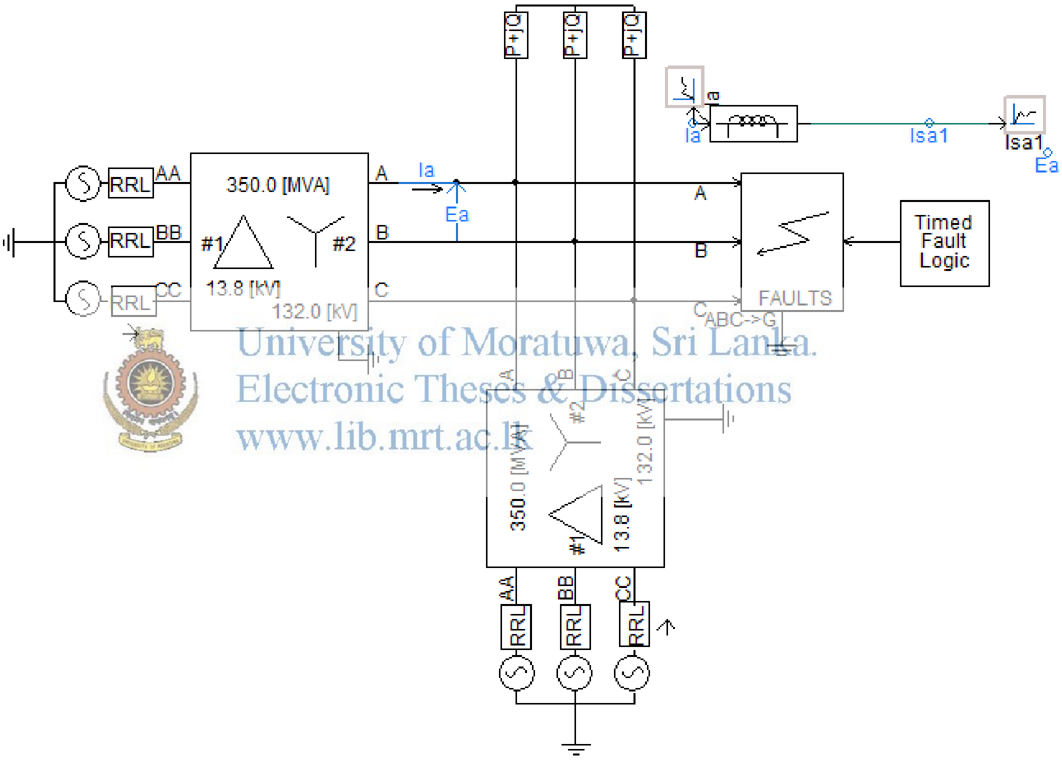

Figure 9-1: Fault Simulated Network

9.1 Core cross section and CT saturation

Figure 9.2 and figure 9.3 compare the CT secondary current variation with core cross section. Figure 9.2 shows secondary current wave at fault with cross section of 0.5 x 10^{-3} m^2 and saturation has not took place. Figure 9.3 shows secondary current wave at same network parameters and same turn ratio with cross section of 0.1 x 10^{-3} m^2.The secondary current wave saturates due to low cross section.

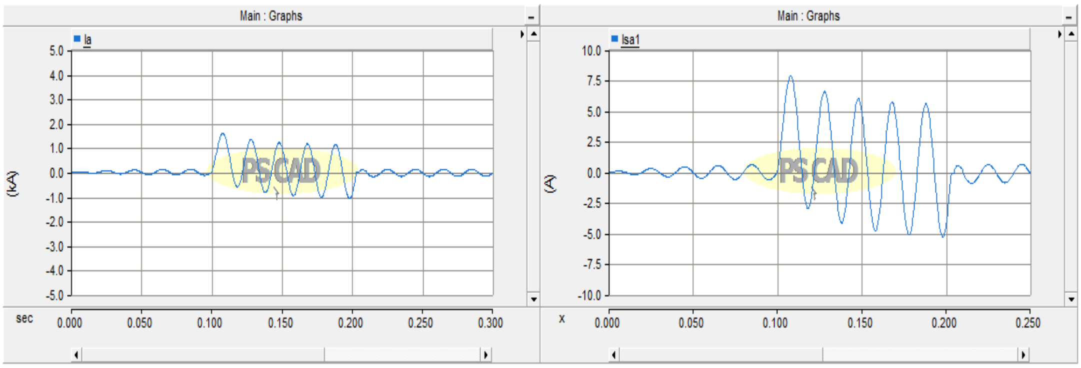

Figure 9-2: Unsaturated secondary current wave with lager cross section (0.5 x 10^{-3} m^2)

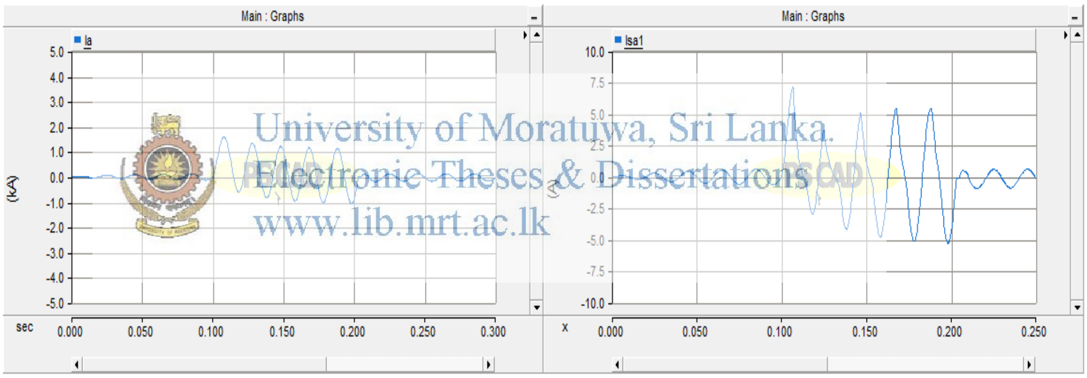

Figure 9-3: Saturated secondary current wave with smaller cross section (0.1 x 10^{-3} m^2)

9.2 Turns ratio and CT saturation

Figure 9.4 and figure 9.5 compare the CT secondary current variation with turns ratio. Figure 9.4 shows secondary current wave at fault with turns ratio of 1: 200 and saturation has not took place. Figure 9.5 shows secondary current wave at same network parameters and same cross section with turn ratio of 1:100. The secondary current wave saturates due to low secondary turns (high secondary current).

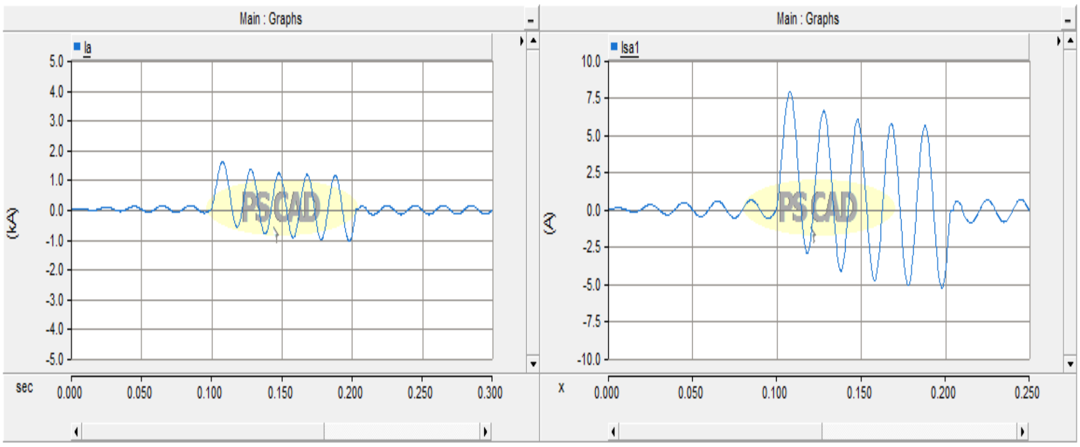

Figure 9-4: Unsaturated secondary current wave with higher secondary turns (200)

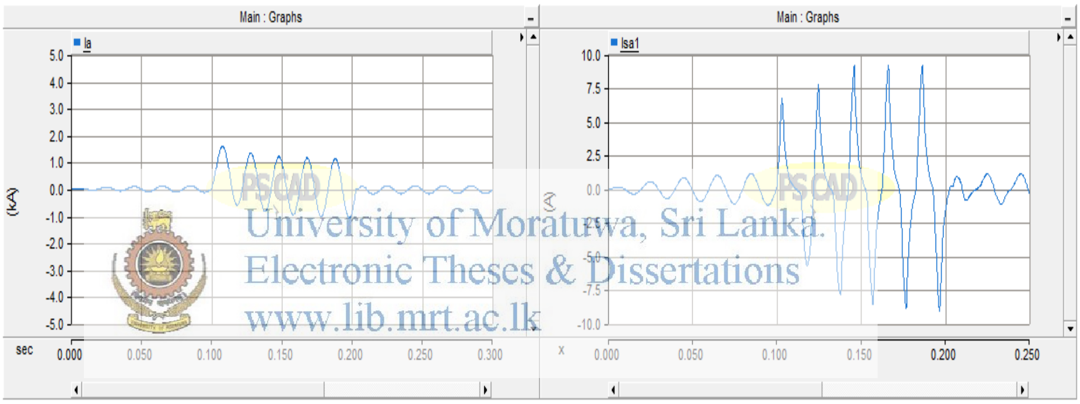

Figure 9-5: Saturated secondary current wave with lower secondary turns (100)

9.3 Burden and CT saturation

Figure 9.6 and figure 9.7 compare the CT secondary current variation with secondary burden. Figure 9.6 shows secondary current wave at fault with lower burden of 0.5 Ω and saturation has not took place. Figure 9.7 shows secondary current wave at same network parameters and same cross section and same turn ratio with secondary burden of 2.5Ω.The secondary current wave saturates due to high secondary burden.

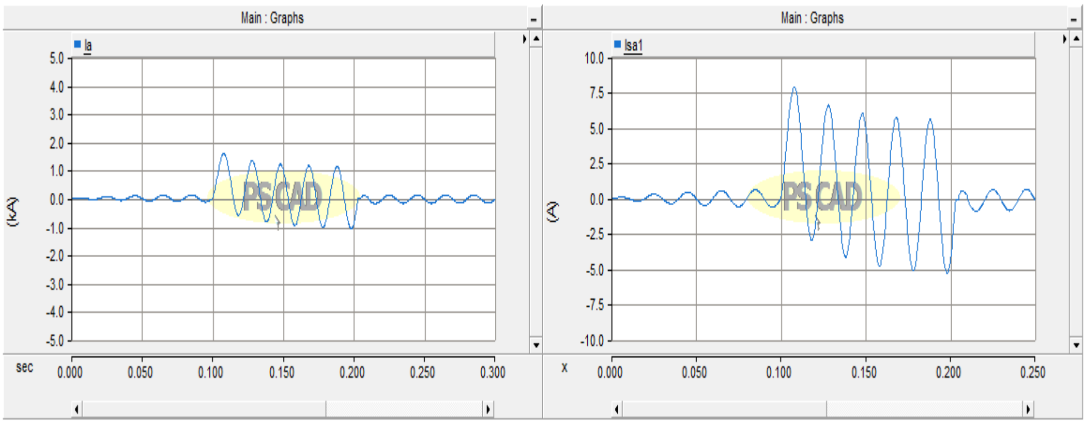

Figure 9-6: Unsaturated secondary current wave with lower secondary burden (0.5Ω)

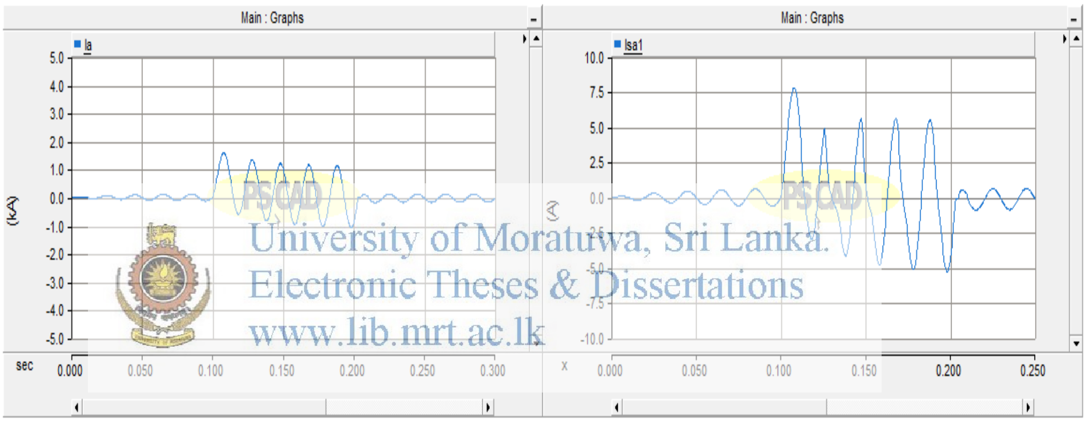

Figure 9-7: Saturated secondary current wave with higher secondary burden (2.5Ω)

9.4 Remanence flux and CT saturation

Figure 9.8 and figure 9.9 compare the CT secondary current variation with remanence flux. Figure 9.8 shows secondary current wave at fault with lower remanence flux of 0.1T and saturation has not took place. Figure 9.9 shows secondary current wave at same network parameters, same cross section, same burden and same turns ratio with remanence flux of 1.5 T. The flux due to secondary current superimposes with high remanence flux and CT core tends saturation.

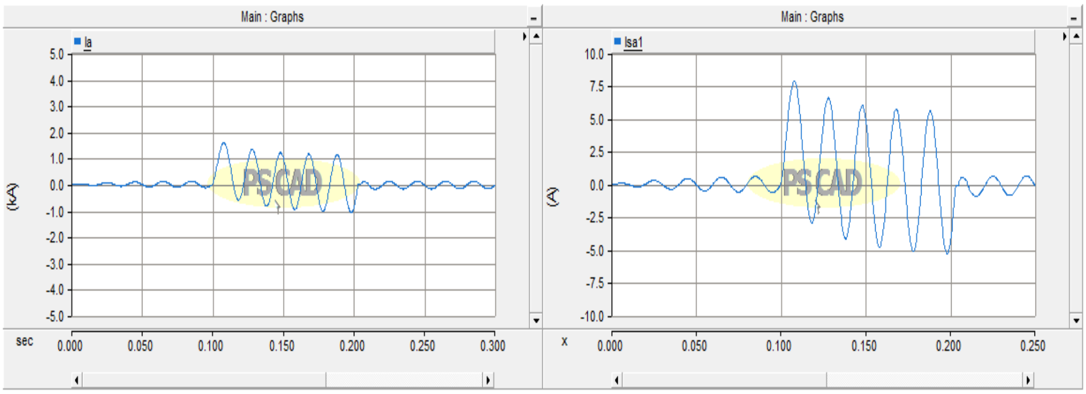

Figure 9-8: Unsaturated secondary current wave with lower remanence flux (0.1T)

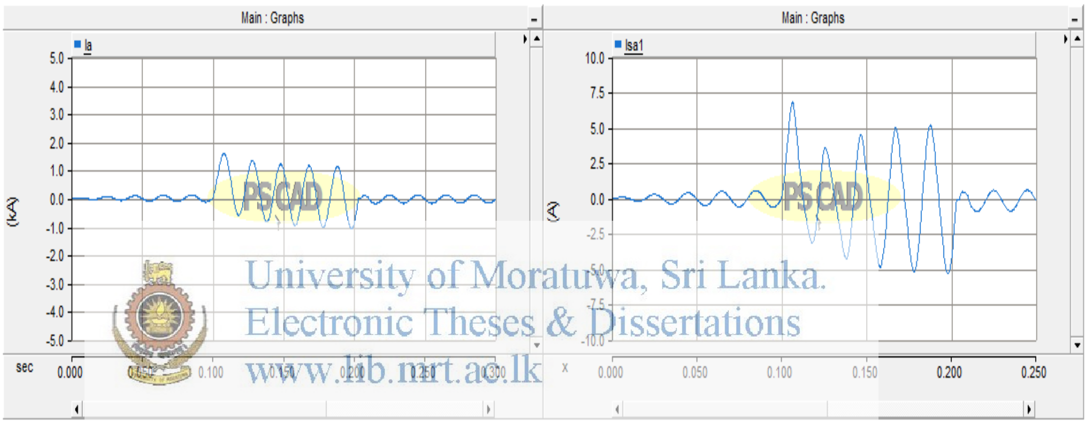

Figure 9-9: Saturated secondary current wave with higher secondary remanence flux (1.5 T)

CHAPTER 10

CONCLUSION AND RECOMMENDATIONS

10.1 Conclusion

Despite of protection relay type, correct CT class selection and optimum CT sizing are mandatory requirements for proper protection relay functioning. In case of instantaneous protection functions, such as differential and distance protection, transient behavior of CT makes high influence of correct operation of CT. Therefore, transient class CTs are more suitable for differential protection and distance protection.

In case of CT sizing for numerical protection relays, fundamental CT sizing calculation for over dimension factor (K_{td}) using line and CT parameters provides better guideline and this value should be compared with K_{td} that is given by protection relay.

In through fault condition of differential protection, critical fault clearing time of faulty branch can be used as more effective time parameter of CT sizing.

Not only the fault current, maximum possible current including fault current and transformer inrush current which affect to CT has to be evaluated in CT sizing.

10.2 Recommendation

The above developed criterion (Chapter 8) is recommended for selection of protection CTs.

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STUDY OF CURRENT TRANSFORMER PERFORMANCE DURING TRANSIENT CONDITIONS AND DEVELOPMENT OF A SELECTION CRITERION IN PROTECTION APPLICATIONS

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