School of Electrical Engineering

Economic Assessment of Fault Current Limitation and Power Flow Control Techniques in Subtransmission Networks

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Abstract

Supplying uninterrupted and high quality electric power to the customer is a priority in the current power systems. Electricity, as a commodity, represents the motive force of modern society and its deprivation causes costly losses for essential parts of the economy in any region.

This thesis performs a reliability study on a fictional test network, employing several techniques to control fault current and power flow in meshed 110-kV subtransmission systems. More specifically, this work tests traditional and recent alternatives applied to cases in which underground cables (UGC) and overhead lines (OHL) are installed in parallel circuits for optimized performance. Economic assessment is handled in order to provide the most inexpensive and reliable solutions, accrediting load growth prediction for a review time of 40 years.

Moreover, fault analysis and power flow simulations are implemented to confirm efficacy and operational viability under contingency conditions of the chosen techniques and technologies. It is imperative to realize that the simulations and reliability studies were conducted in a simple 4-bar network. However, this simplified model can be adapted to any 110-kV urban subtransmission network without major alterations.

Keywords

Subtransmission networks, Meshed Systems, Reliability, FCL, Reactive Compensation, FACTS.

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Tiivistelmä

Tärkeintä nykyaikaisessa sähköverkossa on taata asiakkaille keskeytymätön ja korkealaatuinen sähkönjakelu. Nyky-yhteiskunnassa sähköllä on merkittävä rooli kulutushyödykkeenä ja sähkön jakeluongelmat voivat aiheuttaa taloudellisia tappioita mille talouden osa-alueelle tahansa ja millä maantieteellisellä alueella tahansa.

Tässä diplomityössä luotettavuustutkimus suoritettiin kuvitteellisessa koeverkossa hyödyntämällä useita tekniikoita, joiden avulla kontrolloitiin vikavirtaa ja tehonhallintaa 110 kV silmukkaverkoissa. Lisäksi tässä tutkimuksessa testattiin perinteisiä sekä nykyaikaisempia vaihtoehtoja, joita sovellettiin tapauksiin, missä maakaapelit ja ilmajohdot on asennettu rinnakkaisiin piireihin toiminnan optimoimiseksi. Taloudellinen tarkastelu on tehty siitä näkökulmasta, että löydettäisiin kustannustehokkain ja luotettavin ratkaisu, jossa on otettu huomioon kuorman kasvuennuste 40 vuoden aikavälillä.

Vikavirta-analyysi- sekä tehonhallinta simulointeja on toteutettu, jotta voitaisiin taata tehokkuus ja toiminnallinen toteutuskelpoisuus muuttuvissa olosuhteissa valittujen toimintatapojen ja teknisten ratkaisujen puitteissa. On syytä huomata, että simuloinnit ja luotettavuustarkastelu suoritettiin yksinkertaisessa neljän sähköaseman verkossa. Tätä yksinkertaistettua mallia voidaan kuitenkin ilman suuria muutoksia soveltaa kaikille 110-kV taajamien jakeluverkoille.

Avainsanat

Jakeluverkot, silmukkaverkot, luotettavuus, FCL, reaktiivinen kompensointi, FACTS.

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Bruno Sousa

Espoo, December 2011

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List of Acronyms

AAAC: All Aluminum Alloy Conductor

AAC: All Aluminum Conductor

AC: Alternate Current

ACAR: Aluminum Conductor Alloy Reinforced

ACSR: Aluminum Conductor Steel Reinforced

CAIDI: Customer Average Interruption Duration Index

CAIFI: Customer Average Interruption Frequency Index

CIGRE: International Council on Large Electric Systems

CHP: Combined Heat & Power

DC: Direct Current

DF: Discount Factor

DG: Distributed Generation

EAC: Equivalent Annual Cost

EHV: Extra-High Voltage

FACTS: Flexible Alternate Current Transmission System

FCL: Fault Current Limiter

GIL: Gas-Insulated Line

GIS: Gas-Insulated Substation

HPOF: High-Pressure Oil Filled

HTS: High-Temperature Superconductor

HV: High Voltage

IEC: International Electromechanical Commission

IEEE: Institute of Electrical and Electronics Engineers

LV: Low Voltage

MFCL: Magnetic Fault Current Limiter

MV: Medium Voltage

N_2: Nitrogen Gas

NDE: Non-Distributed Energy

OHL: Overhead Line

PD: Partial Discharge

POD: Power Oscillation Damping

PPLP: Polypropylene Laminated Paper

PST: Phase-Shift Transformer

SAIDI: System Average Interruption Duration Index

SAIFI: System Average Interruption Frequency Index

SCFCL: Superconducting Fault Current Limiter

SF_6: Sulfur Hexafluoride

SFCLT: Superconducting Fault Current Limiting transformer

SIL: Surge Impedance Loading

SN: Superconductive-Normal Transition

SNT: Sequential Network Tripping

SSFCL: Solid-State Fault Current Limiter

SSR: Subsynchronous Resonance

SSSC: Static Series Synchronous Compensator

STATCOM: Static Compensator

SVC: Static VAR Compensator

TCSC: Thyristor-Controlled Series Capacitor

UGC: Underground Cable

UHV: Ultra High Voltage

UPFC: Unified Power Flow Controller

XLPE: Cross-Linked Polyethylene

List of Symbols

$a(t)$	cost *per* unit of power not supplied *per* interruption	[€/kW]
$b(t)$	cost *per* unit of energy not supplied *per* interruption	[€/kWh]
C	single-phase capacitance	[F/m]
C_{cb}	circuit breaker cost	[€]
C_{cd}	conductor cost	[€]
C_{cd_r}	conductor repair costs	[€]
C_{CIC}	customer interruption cost	[€]
C_{cp}	compensation scheme costs	[€]
C_{eq_r}	equipment (busbar, transformer & circuit breaker) repair costs	[€]
C_{inv}	investment cost	[€]
C_{losses}	loss cost	[€]
C_{out}	outage cost	[€]
$C_{o\&m}$	operation and maintenance cost	[€]
C_t	total cost *per* feeder section	[€]
C_{total}	total cost	[€]
CN	total number of customers experiencing interruption	
d_{eq}	equivalent distance between phases	[m]
d_{sh}	sheath (insulator + conductor) diameter	[m]
E	surface potential gradient	[kV_{RMS}/m]
E_j	non-distributed energy to load j	[kWh]
H	height from the center of the conductor to ground	[m]
h_{wk}	load losses price	[€/kWh]

I_b	base current	[A]
I_p	peak short-circuit level	[kA]
I_{sc}	short-circuit level	[kA]
k_c	discount factor for constant relation with load growth	
k_l	discount factor for linear relation with load growth	
k_{load}	discount factor for load-related costs	
k_{loss}	discount factor for loss-related costs	
k_q	discount factor for quadratic relation with load growth	
l	conductor length	[km]
L	single-phase inductance	[H/m]
n	number of feeder sections	
N_i	number of customers interrupted	
N_T	total number of customers	
p	annual interest rate	[%]
P	active power	[W]
P_{loss}	power losses	[kW]
P_{ns}	power not supplied	[kW]
$pf\ (= \cos\phi)$	power factor	
Q	reactive power	[VAr]
r	load growth rate	[%]
r_c	conductor radius	[m]
r_i	restoration time for interruption event	[h]
r_j	average outage duration for load j	[h]
r_{sh}	sheath (insulator + conductor) radius	[m]
R_{th}	Thévenin resistance	[pu]
S	apparent power	[VA]

S_n	nominal rated power	[MVA]
S_t	present value of money	[€]
S_0	initial sum of money	[€]
t	year posterior to investment	[a]
T	load-growth period	[a]
t_{ij}	outage time at load point j caused by failure in component i	[h]
T_{out}	averaged outage time	[h]
T_{peak}	peak utilization time	[h/a]
t'	review year	[a]
U_j	annual unavailability for load j	[h]
U_r	voltage at receiving terminal	[kV]
U_s	voltage at sending terminal	[kV]
V	phase-to-ground voltage	[kV]
x_1	conductor reactance for positive sequence	[Ω/km]
X_L	line reactance	[Ω]
X_{th}	Thévenin reactance	[pu]
Z_{th}	Thévenin impedance	[pu]
α	present worth factor	
δ	torque angle	[rad]
ε_0	vacuum permittivity	[F/m]
ε_r	relative permittivity	
κ	factor	
λ	average failure rate	[failure/a]
λ_j	average failure rate for load j	[failure/a]
λ_l	average failure rate for long independent outage	[failure/a]
λ_s	average failure rate for short independent outage	[failure/a]

μ	average repair time	[h]
μ_l	average repair time for long independent outage	[h]
μ_s	average repair time for short independent outage	[h]
μ_0	vacuum permeability constant	[H/m]
ρ	electrical resistivity	[Ω.m]

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Chapter 1: Introduction

1.1. The Power System

Power systems behold major importance to support human welfare in modern society. Electricity, which is transmitted through power systems, is nowadays replaced in tasks formerly accomplished by wood, natural gas, coal, oil, animal and human power.[1] This is a reasonable statement, for electricity presents interesting features in face to other commodities. Electricity is not storable; hence, it requires a physical transmission system that permits uninterruptable flow of energy.[2] Consequently, several considerations must prevail in order to permit continuous flow from supply points till load areas.

Presently, the power system represents a very complex arrangement of interconnected networks compound by loads, busbars, generators, compensation equipment, transmission lines, transformers and ancillary equipment. The purpose of any electrical power system is to generate, transmit and distribute electricity to the customer. Similarly, this electricity delivery must meet satisfactory levels regarding to availability, cost, quality and reliability, as well as afford safety to third parties and low environmental impact. The current model for the power system adopted world-wide is typically segmented in generation, transmission, distribution and commercialization.[3] In the context of this thesis, power system is denominated as the Finnish power system (distribution, subtransmission, transmission and generation networks at the respective voltage levels) and the terms “network” and “system” are employed as synonyms.

The topology in power systems varies in size, design and operation. Hospitals, residential blocks, commercial buildings, ships and factories are examples of smaller power systems. Power systems often rely upon the three-phase alternate current (AC) power, which is a globally accepted standard. However, more specific systems, such as electrified railway systems, work by the usage of direct-current (DC) power.

The voltage level is the feature used to ramify power systems in distinct parts. This level classification incorporates very broad meaning and thereby there is not a universally consummated definition for it. It depends on the context to which it is applied. For instance, the International Electromechanical Commission (IEC) divides AC three-phase systems in groups,[4] according to **Table 1**. In addition, other organizations, such as the Institute of Electrical and Electronics Engineers (IEEE), establish that medium voltage range from 1 to 35 kV for devices and rated values over than this is regarded as high voltage.[5]

Table 1: Nomenclatures used to represent different voltage levels.[6]

System	*Nominal Voltage V [kV]*
LV	$V \leq 1$
MV	$1 < V \leq 35$
HV	$35 < V \leq 230$
EHV	$230 < V \leq 800$
UHV	V = 1050 or 1200 (practiced in the USA)
Notes: - For voltages over LV, it is used HV unless when voltage range is specified; - For transformers: low-voltage side (LV); and high-voltage side (HV).	

In order to keep optimum usage of the power system, extra-high and high voltage levels are used in transmission; medium voltage, in generation; and medium and low voltages, in distribution systems. This hierarchical structure has been developed throughout the last century, proving to be the most efficient mean to transport electricity from generation sites to unevenly distributed customers.

In Finnish reality, 400 kV and 220 kV are employed in transmission; 110 kV, in subtransmission; and 20 kV and 0,4 kV, in distribution of electricity.[7-9] Furthermore, transmission and subtransmission systems in Finland are characterized to be typically meshed or looped, while distribution relies on radial configuration.[9]

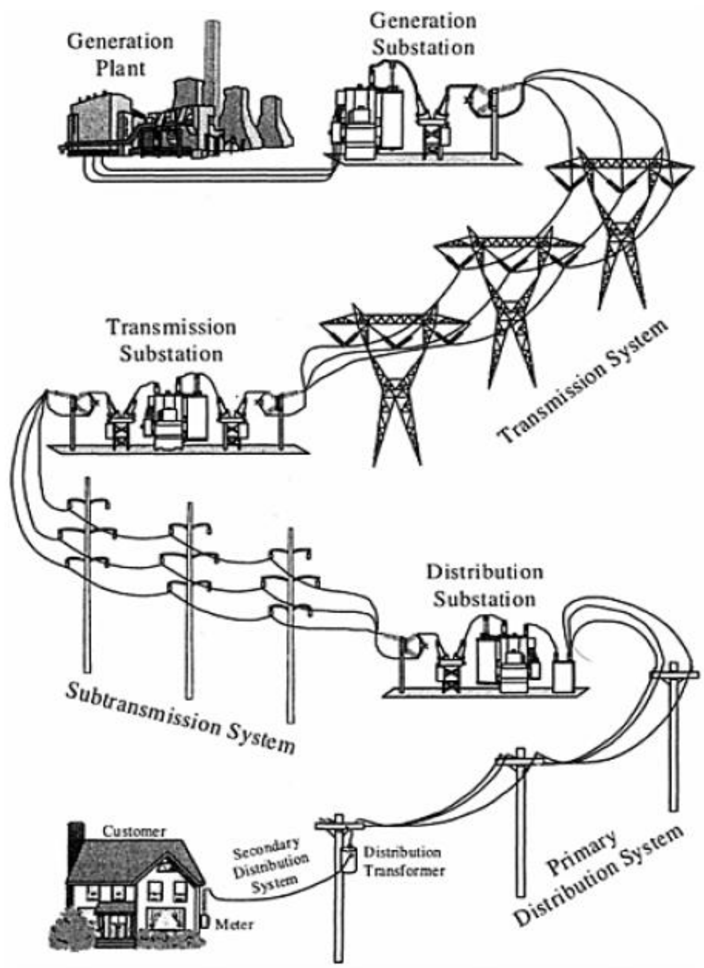


Figure 1: An example of a typical power system (from generation to consumers).[10]

Figure 1 schematizes a simplified example of an electric power system from generation to residential customer. It is imperative to recollect that customers are present at different voltage levels, not only at the "end point". For this reason, transmission, subtransmission, primary and secondary customers are classified according to the part of the power system that they are connected.

1.2. The Subtransmission Network

The subtransmission network is the area in which this thesis mainly presides. More specifically, a fictional generalized 110-kV subtransmission network, depicted in **Figure 2**, is the focused case study. This subtransmission system consists of four HV substations, two subsystems (feeding bar I and feeding bar II); additionally, overhead lines (OHL), and underground cables (UGC) are used as connectors. For detailed information of the depicted network, *vide* **Chapter 5** and **Appendices** sections.

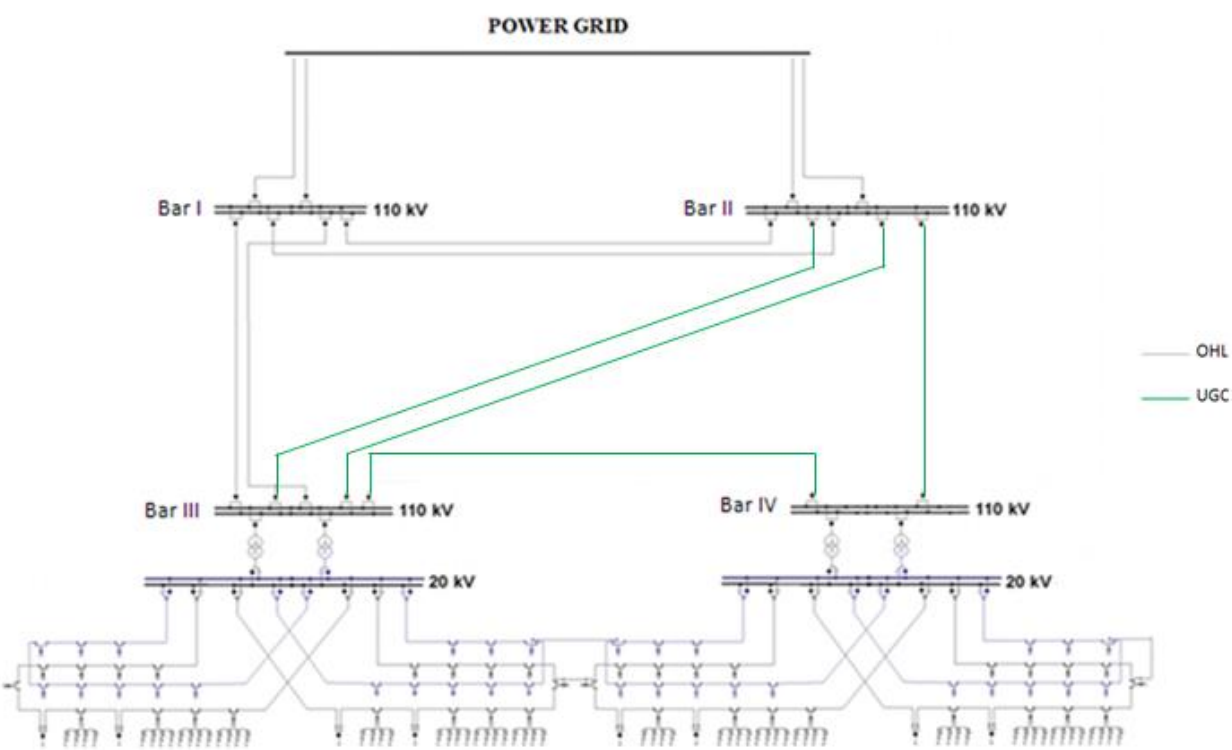


Figure 2: The test network studied (110-kV subtransmission system).

It is defined that transmission lines whose main function is to inject power into distribution substations are referred as subtransmission lines.[11] The subtransmission network connects transmission to distribution substations. It also connects specific customers, denominated subtransmission customers, to the transmission substation. These customers are generally major industrial facilities that receive power at subtransmission voltage levels (from 34,5 kV to 230 kV).[10]

The distinction between transmission and subtransmission networks might be tenuous, for transmission lines can also link transmission to distribution substations. Nevertheless, the voltage levels and the length of lines are features that distinguish these systems. Another feature is that the capacity of subtransmission lines range from 30 MVA to 500 MVA, whereas in transmission lines it can reach over 2000 MVA (in the case of HVDC links, the capacity could reach as high as 7200 MW).[11,12]

Subtransmission circuits may be constructed in radial, in loop (open or closed) or in grid (meshed) topology. **Figures 3** and **4** present some examples of configuration in the subtransmission circuit. In some instances, these circuits are used as ties between two or more power sources. Two or more subtransmission feeders (or sections of feeder) are routed along in order to provide greater adequacy and security for the system. However, the complexity of the protective relaying scheme in the subtransmission network, particularly for the meshed scheme, and the number of circuit breakers employed could represent a major disadvantage.[13]

The redundant nature of meshed networks supports reliability of the network, particularly during the loss of a feeder in the case of fault, nonetheless. In other words, the chosen topology presents a major impact on the total costs of the subtransmission network.

Furthermore, a number of criteria should be respected to assess the reliability of subtransmission systems, extending to the well-functioning of the entire power system. As an example, probabilistic methods respond well to the stochastic complexion of power demand and component failures due to contingencies in the system.

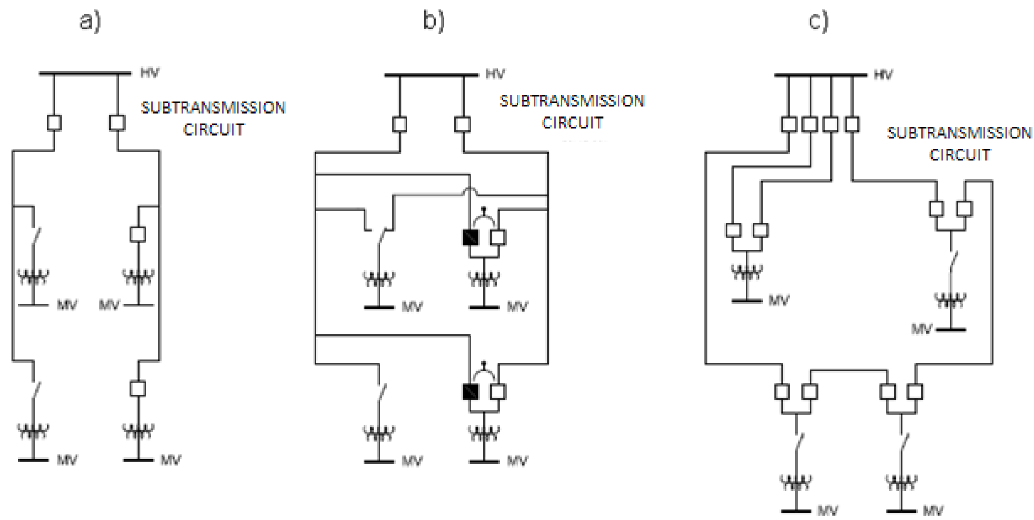


Figure 3: Common subtransmission network configurations: a) radial; b) improved radial (the black circuit breakers are normally open and interlocked with a second breaker automatically); and c) looped.

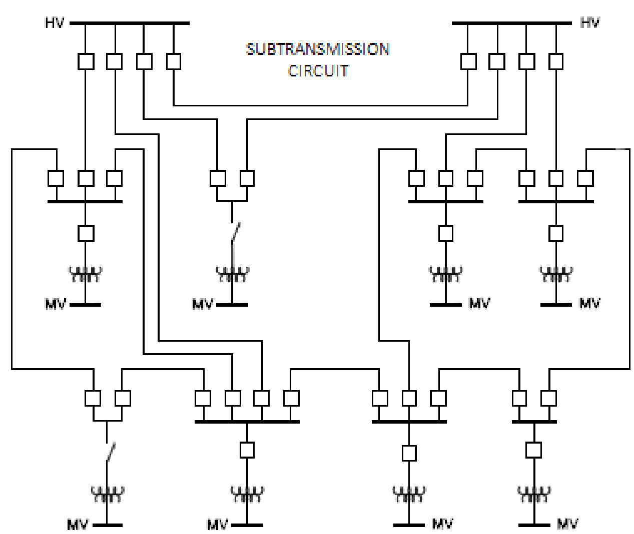


Figure 4: Meshed or grid configuration of subtransmission networks. Number of circuit breakers and complexity of protection may represent a barrier for fault level and power flow controls.

In spite of the shorter length, the fault frequency in subtransmission lines is higher than in the transmission network. On the other hand, in comparison with the distribution networks, it is significantly smaller. For instance, the fault occurrence in MV overhead lines can be remarkably high, reaching over 30 faults per 100 km per year.[14] Intrinsically voltage sags originated by faults are propagated; further, because of the meshed nature and depending on the position and magnitude of the fault in the subtransmission and transmission networks, as well as the type of earthing engaged, these sags affect a larger area than if originated from the MV side.[15]

Table 2: Fault frequencies and shares of different fault types for Finnish transmission systems.[15]

Voltage [kV]	Fault Frequency [per year per 100 km]	Share of Different Fault Types [%]			
		1-phase earth faults	2-phase short-circuits	3-phase short-circuits	2- or 3-phase earth faults
110	3,50	81	3	2	14
220	0,72	78	2	3	17
400	0,28	80	2	3	15

1.3. Research Problem

The zone at which this thesis is presented represents great importance to the continuity of the electricity supply. For this reason, there is an urge to confront the existing bottlenecks in the subtransmission system in order to maintain its well-functioning. One of these issues is the optimal operation of OHLs and UGCs in parallel paths under contingency conditions.

Due to exogenous factors, particularly by meteorology phenomena, faults in OHLs occur much more frequently than in UGCs. As that happens, the loss of OHLs during fault conditions might overload parallel UGCs in a destructive level leading to interruption of the electricity supply and damage to the cable insulation. This can be explained by the significantly lower impedance values *per* kilometer and the diminished ampacity in UGC (for thermal limitation) comparing to OHL. The latter possesses intrinsically larger resistance and inductance *per* kilometer as well as higher ampacity than the previous. In some cases, depending on the network configuration, several parallel feeders, in special the ones compound by UGCs, are isolated from the network as a result of the activation of protection subsequent to fault. Consequently, a larger number of customers are not supplied, thus setting the regional operator under legal jurisdiction by the form of fine.

Available techniques for fault current limitation and power flow control involving traditional and novel solutions are depicted and analyzed in the form of reliability study on the purpose to frame flexibility for the considered grid. Moreover, inspection of technical and economical performances for each chosen technology and configuration is described to yield to optimum parallel operation of underground lines and overhead cables.

In the context of this thesis, the analysis of fault levels and power flow control are accomplished in two parts: the case networks; and the test network. In the first, the analysis is evaluated individually in different network configurations utilizing the same four-busbar structure of the test network. In the second, the most straightforward techniques are applied to the test network, depicted in **Figure 2**, to provide comparison at same network.

1.4. Main Contribution of the Thesis

In this thesis, the main contributions are:

- Investigation of fault current and power flow control techniques and technologies currently available for meshed subtransmission systems;
- Study of technically and economically viable alternatives for optimal parallel operation of underground cables and overhead lines in existing 110-kV networks in order to increase system capacity avoiding expansion;

- Cost-based optimization of several network configurations and comparison of fault current and power flow solutions;
- Economical assessment of selected technologies in a general four-busbar 110-kV network, providing input to possible usage of these alternatives in real urban subtransmission networks.

Chapter 2: Cables & Lines in Subtransmission Networks

2.1. Overhead Line

Overhead lines (OHL) are widely employed in the transportation of electricity by suspending bare-wire conductors whose insulation is mainly provided by the air. Since early stages of the development of distribution and transmission networks, adequate insulation technology for higher voltages has favored the dominance of overhead lines.

Suspended lines are constructed over supporting structures, towers (also known as pylons), which are distant from each other according to several factors. Namely, the voltage level, the weight of the conductors (directly related to the cross-section and material utilized), wind loadings and weather conditions are some of the determinant variables when specifying towers and lines.

Currently, OHLs are present in diverse areas, including limitedly accessible and extreme environments of the planet, such as rainforest, deserts, subpolar, urban and mountainous areas. For environmental and security purposes (to both networks and human/animal integrity), design and project of OHLs involve important technical considerations. Areas in the corridors formed by the lines must be cleaned from trees and other obstacles as well as be isolated by a pre-determined distance from public access.

Public awareness of environmental impact and restricted availability of natural resources draw constant research from the side of engineers and companies providing optimized networks.[16] Consequently, the material and technology employed represent deterministic features in the composition of the total cost of the lines.

2.1.1. Physical Structures

In OHLs, structures present a variety of forms according to project specifications. Phase spacing, height of average conductor, number of subconductors and their separation in bundle configuration are part of the considered parameters.[16] Accordingly, the main three components of overhead lines are portrayed: conductor, insulation and towers.

I. Conductors:

The live part of OHLs functions as the central part of transmission and distribution of electricity. As a consequence, conductors must be isolated and carefully installed to avoid contact between each other and the supporting towers. Conductors of overhead lines are distinguished for not presenting any insulation coatings, *i.e.*, they are actually bare-wire conductors. These conductors are flexible and present uniform cross-sectional geometry and weight per unit of distance. Additionally, the distance between the highest and the lowest points of the curve, when placed on pylons, varies according to the surrounding temperature and to the conductor weight.

The most used materials for conductors are copper, for low voltages and grounding wiring, and aluminum, for medium and high voltage systems. The latter is widely employed, for its enhanced electrical properties, such as lower resistance per unit of weight of material, as well as its lower price in comparison to copper cables.

There are different types of alloys employed with aluminum for conductors, such as aluminum conductor steel-reinforced (ACSR) – which is the most widely employed type – all aluminum alloy conductor (AAAC) and aluminum conductor alloy reinforced (ACAR). Also, all aluminum conductor (AAC) is available. The presence of a stranded-steel core comprises mechanical strength to the conductor. These conductors can present deposited zinc-coated (galvanized) layers to provide anti-corrosive protection.

A code name (*e.g.* duck, finch and ibis) is attributed to identify the diameter, the rate of aluminum-steel strands and the physical-electrical properties attributed to each type of conductor. Conductors based on aluminum or aluminum alloys are frequently described in terms of copper equivalent, *i.e.*, the equivalent cross-sectional area of copper conductor presenting the same value of DC resistance of the featured aluminum line.

Figure 5: Bare overhead ACSR conductors: concentrically-stranded conductor with 3 layers of wires around a steel core (left); concentrically-stranded conductor with trapezoidal layers of wires around a steel core (right), this type of conductor provides 20% extra ampacity for the same given diameter.[17]

The wire shape that compose the geometry of the conductor, *vide* **Figure 5**, can present circular or trapezoidal cross-sectional area. The latter type is engaged in order to maximize ampacity given a diameter of a cross-section.[18]

One other technique used to optimize operation is to assemble the conductors in bundles. This solution is necessary to minimize the corona effect in extra-high voltages lines. The corona effect occurs when the dielectric strength of surrounding air is broken by the surface potential gradient of a conductor. This effect induces ionization of the region around the conductor, producing power losses as consequence. Similarly, it causes radio interference in communication channels and it produces a continuum buzz as well as discharges ozone into the surrounding area.[19] The surface potential gradient is considerably reduced by allocating 2 to 4-

conductor bundles *per* phase by regular distances. Spacers are inserted between the bundled conductors to avoid touch during wind gusts. This is a practice introduced in systems operating over 200 kV.

II. Insulators:

Good performance of electrical networks largely depends on well-insulated protection schemes. Insulation is provided by parts notably designed to support conductors on towers under whichever possible situation. Insulators must withstand lines mechanically and electrically, namely when a lightning strikes the network, during strong storms or surges (caused by switching maneuvers).

Insulators are manufactured in different shapes and materials. Traditionally, ceramics and toughened glass have been used; however, polymers and other synthetic materials with optimized dielectric properties have been increasingly implemented in extra-high voltage systems. Examples of widely utilized types of insulators are the disk, pin, shackle, pot and Longrod types.[20] Altogether, a good insulator must provide good hydrophobic nature (intrinsic to dielectric materials), low weight of its spare parts and low moist and dirt accumulation over its surface.

III. Towers:

Towers represent an expensive part of any project of overhead lines. Not only when speculating the shortest and most economical path, but also selecting the least environmentally-harmful way portrays the most important factors considered in the project design. In many cases, lines need to be supported over different terrains, demanding earth-rock excavation and provoking soil erosion.[21]

Towers in power systems behave as suspension, tension or transposition agent, according to the working principles of the employed structure. In the case of transposition towers, the phase cables are transposed alternately in order to equalize cable impedance in relation to the ground and to minimize mutual interference between the phases.

Furthermore, towers are designed to support lines despite weather conditions and even to more violent cataclysms, such as earthquakes. As a result, depending on the availability of the material and the mechanical load which towers must withstand, they can be fabricated in steel, concrete, wood or a combination of these. Electro-mechanical assembly details of towers and overhead lines are out of the scope of this thesis.

Table 3: Average height (H) and average span (S) of towers in **Figure 6**, from left to right.

	115 kV			230 kV				500 kV			
H [m]	19,8	27,5	22,9	25,9	36,6	33,6	35,0	41,2	38,0	51,9	51,9
S [m]	228,8	274,5	350,8	350,8	350,8	274,5	274,5	350,8	350,8	350,8	350,8

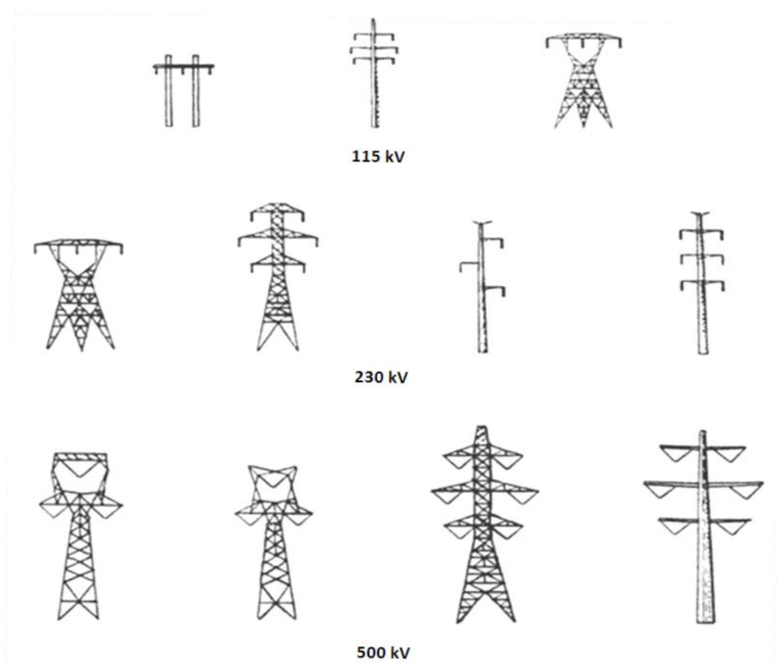


Figure 6: Examples of design of transmission towers at 115 kV, 230 kV and 500 kV.[22]

The size and format of towers and the number of circuits *per* network vary significantly according to the voltage level and the power rate of the system. Defined distances between conductors and between conductors and soil exist to maintain enough insulation and to avoid interference or contact between different phases. Two or more circuits are added to balance weight at HV and EHV levels. In addition, it is also possible to accommodate parallel circuits (circuits at different voltage levels) in the same towers. Likewise, overhead power lines are equipped with ground wires placed on the topmost part of the tower to minimize the incidence of lightning strikes directly to the live conductors.

Generally, the maximum potential gradient is localized in the center phase and is given by the equation:

$$E_{OHL} = \frac{\sqrt{2}V}{r_c \ln\left({}^{2H}/_{r_c}\right)} \qquad \text{(eq. 1)}$$

E_{OHL}: OHL surface potential gradient [kV_{RMS}/m];
V: phase-to-ground voltage [kV];
H: height from the center of the conductor to ground [m];
r_c: conductor radius [m].

A survey held in transmission lines stated that maximum potential gradients vary from 12,4 to 21,4 kV_{RMS}/cm.[16]

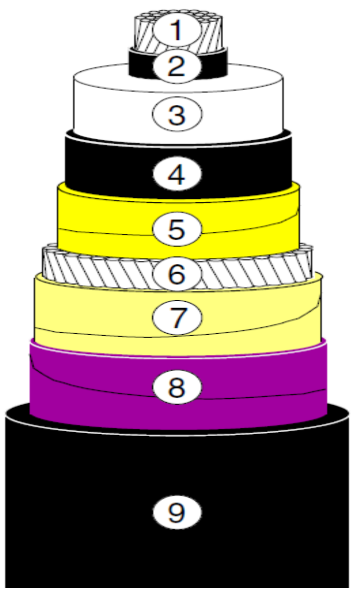
In recent years, it been has shown negative response from the public to transmission towers and OHLs on account of the increasing awareness of environmental impact and also the collective feeling that these constructions represent visual pollution in urban areas. Additionally, controversies about electromagnetic fields from OHLs and safety issues have concerned population living in surrounding areas. One initiative, for instance, is to install aesthetically appreciable towers away from densely populated area, as the designed ones depicted in **Figure 7**. One other alternative is to introduce underground cables. However, this might not represent an economically nor technically feasible solution.

Figure 7: Salmisaari-Meilahti transmission lines in Helsinki. These are 60-meter landscape towers, designed by Antti Nurmesniemi.[23]

2.2. Underground Cable

During the past decades, underground cables (UGC) have acquired significant importance in high-voltage transmission systems. This was the result of several technological improvements, particularly in materials applied to cable insulation and shielding, fomented by the necessity of supplying electricity through over-congested highly-populated urban areas. These regions frequently comprise of very high real estate value and do not offer enough space to accommodate overhead lines and tower structures. In addition to this, UGCs are very effective in applications, such as under-water power transmission.

A general structural schematic of a UGC is described in **Figure 8**. Conversely, the number of layers might differ depending on the manufacturer technology and the insulating material employed. In the same way as in OHLs, the conductor utilized in UGCs is usually found in stranded aluminum (steel core is not used), for its electrical and physical properties, and copper.



1- Aluminum conductor;

2- Inner semi-conductive layer;

3- Cross-linked polyethylene insulation;

4- Outer semi-conductive layer;

5- Conductive swelling tape;

6- Metallic shield (aluminum);

7- Conductive swelling tape;

8- Coated aluminum tape

9- Protective outer sheath.

Figure 8: Typical construction of XLPE cables.[24,25]

In the schematic depicted, the cross-linked polyethylene (XLPE) insulation provides efficient insulation at 90°C, under steady-state operation, and 105°C under overload.[24] It also assures protection under lightning and switching overvoltage situations. The inner and outer semi-conductive layers (layers 2 and 4) prevent concentration of electric field at the interfaces between the adjacent layers by ensuring physical contact with the insulation (layer 3). The metallic shield introduces electric screen, thus not allowing leakage of electric field to outside the cable, radial waterproofing to the insulation layer and behaves as active conductor for capacitive and zero-sequence currents. And finally, the outer sheath confers robust mechanical protection against external stress (*e.g.* when digging a tunnel and accidentally striking a UGC) and reduces fire propagation.

Altogether, the layered insulation arrangement is intended to provide flexibility and avoid depredation, since damaging the cable structures implies substitution for a new cable, and to grant diminished electric field stressing the insulating layer. Moreover, there is physical limitation caused by the conductor weight, limiting ampacity and cross-sectional area of conductors (for aluminum conductors, one of the largest cross-sections available is 2500 mm^2).

Underground cables, as suggested, are laid under the soil through three main laying techniques: in ducts, in troughs and burial. As result, the thermal factor involves direct effect on the operational performance of UGCs. Certain burial dimensions and practices, including not burying power cables with other types of cables, must be accomplished in order to assure good functioning of the system.[26]

By applying any of these techniques, two major components are considered: the cable and its accessories; and the underground installations to which the cable is laid. The conditions to which cables are installed directly influence the overall costs. Existing underground facilities, such as subway systems, can be utilized, discarding the necessity of building new ones.[27]

UGCs present important accessories that facilitate installation and interface with other systems. Cable terminations and joints must be able to keep electric fields within tolerable values. Sharp ends and joints are avoided to prevent accumulation of electric charges and control of equipotential lines.

Test specifications consist of an important part of the development of cable technologies and accessories. IEC 60840 and IEC 62067 are examples of tests recommended by the International Council on Large Electric Systems (CIGRE).[28] The first includes tests on HV extruded cables and accessories and the second, EHV extruded cable systems.

2.2.1. Available Technology

Cable technologies have been developed since the 19th century for several purposes. They have been employed in cables, in telephony, telegraphy, public lighting systems, electricity distribution and transmission, among others. However, in high voltage and extra-high voltage, cable technology involves an additional level of concern on the material used for the insulation structures and it accounts even more deeply the thermal behavior within steady-state operation.

Three major categories of HV UGCs can be listed: high-pressure oil-filled paper-insulated cables, cables with extruded insulation and high-pressure gas-insulated lines.

I. High-pressure oil-filled (HPOF) paper-insulated cables:

Paper-insulated cables present low dielectric losses and high dielectric strength.[29,30] The electrical insulation in this category consists of liquid, paper-lapped, material, including polypropylene laminated paper (PPLP). In this method, the three phases of a circuit are placed inside a pipe filled with pressurized oil.

This technology in high voltage level has been popular since the middle of the 20th century, although it has been replaced by extruded cabling systems facing gas and oil leakage. Since then, design and constructional improvements have effectively increased while diminishing environmental risks. Lately, cables with PPLP have employed in submarine EHV DC cables.[30]

II. Cables with extruded insulation:

This category includes solid insulating materials, such as cross-linked polyethylene (XLPE) and ethylene propylene rubber (EPR). The first is a polymer developed in the first half of the 20th century that exhibits excellent thermal strength and dielectric properties, such as low dissipation factor. For that, XLPE cables are used in EHV networks.[31,32] The latter type provides very good flexibility representing perfect solution in installations that offers limited maneuverability. These extruded cables in XPLE and EPR are lighter in weight, present reduced risk of flammability and provide larger current capacity than paper-insulated cables.

III. High-pressure gas-insulated lines (GIL):

This is not a cable in the strict sense of the word; it is described as an alternative to OHLs and UGCs, nevertheless. It actually is an underground line insulated with inert gas (sulfur hexafluoride, SF_6, or nitrogen gas, N_2). It is similar to UGC in the fact that it has to be buried underground. GILs are employed in short distances to interconnect power plants to overhead lines or between gas-insulated substations (GIS).[33]

GIL operates with recent technology, being the first line commissioned in 1975.[34] It is outlined as an expensive system network and might represent danger to the environment, for the most used gas as insulation mean, SF_6, is a greenhouse gas. However, GILs involve very low power losses and capacitive loads in the lines are in the same order as OHLs due to the gas insulation. Given that, GILs can reach longer length than UGC.[35]

Several researches are held to develop enhanced materials, providing sufficient insulation without damage to the UGCs as well as to minimize the thermal effect to keep high capacity rates in UGC systems. The XLPE-insulated cable technology performs continuous improvements in the quality of insulation, permitting reduction in the insulation coating thickness, lowering investment costs.

The maximum stress in UGC is given by:

$$E_{UGC} = \frac{\sqrt{2}V}{r_c \ln\left({r_{sh}}/{r_c}\right)} \qquad \text{(eq. 2)}$$

E_{UGC}: UGC surface potential gradient [kV_{RMS}/m];
r_{sh}: sheath (insulator + conductor) radius [m];
r_c: conductor radius [m].

As inferred from the **Equations 1** e **2**, the maximum values for potential occurs in the inner semi-conducting layer.

Also, hazardous discharge mechanisms, including partial discharge (PD), which occur when dielectric breakdown caused by the stress of overvoltages degrades insulating parts of cables or any other large electrical equipment, compromise UGCs. Techniques to identify and localize PDs are under development and represent major contribution to the well-functioning of HV systems.[36-38]

2.2.2. Thermal Behavior in UGC

More than in overhead lines, thermal transfer in underground cables is a critical factor. UGCs are protected by layers of insulating material and, in addition to that, these cables are buried underground keeping the thermal dissipation more difficult, depending on the type of burial and thermal conductivity of surrounding environment.

In UGCs, heat is generated from conductor and sheath losses which are current-dependent factor, as well as from dielectric losses which are a voltage-dependent factor. Heat is transmitted by thermal mechanisms (*e.g.*, conduction, between conductor and insulation;

and convection, radiation or/and conduction, between cable and the surrounding environment depending on the employed laying technique).[39] As consequence, cable nominal power rating is diminished in comparison to lines, given a conductor nominal cross-sectional area using the same material.

2.3. Modeling of OHLs and UGCs in Power Systems

For the circuit analysis held in this thesis, line resistance, inductance and capacitance are the most representative parameters of interest. Underground cables are modeled by the same parameters as overhead lines. However, some considerations have to be acknowledged for both cases.

I. Resistance:

Any material used to construct wires brings a resistive component to the circuit. The resistive component causes power losses, consequently heating in the conductors. In addition, as the material specific resistance is function of the ambient temperature, power transfer capacity in transmission lines is reduced, as temperature is increased. Resistance has also effects on the attenuation of propagating waves in lines during switching and lightning events.

As a result of the skin effect, conductors consist of smaller effective cross-sectional area. For this reason, AC resistance measurement is supplied.

The resistance of stranded conductors is:

$$r = \frac{1337\rho}{d_s^2 n_s} \qquad \text{(eq. 3)}$$

r: resistance of stranded conductors per unit of distance [Ω/m];

ρ: electrical resistivity [Ω.m];

d_s: strand diameter [m];

n_s: number of strands.

Equation 3 is valid for both cables and lines in different conductor material. Both resistivity of the material (ρ_{Al} = $2{,}82.10^{-8}$ Ω·m and ρ_{Cu} = $1{,}68.10^{-8}$,at 20°C) and the number of stranded conductors have to be accounted in the case which copper or aluminum is used. Likewise, for UGCs, the insulation resistance is also computed and renders information about how effective is the insulating material. In catalogues, it is common to observe values for DC resistance at 20°C and AC resistance at 50°C and 50/60 Hz.[40]

II. Capacitance and Inductance:

For load flow and balanced-fault analysis in three-phase systems, phase-to-neutral (hypothetical neutral conductor) voltage is used. The analysis is performed in only one phase and for the other two phases, the correct angular adjustment is inserted. Since phase-to-neutral voltage values are used, capacitance and inductance, also phase-to-neutral, are respectively:

$$C = \frac{2\pi\varepsilon_0}{\ln\left[{(d_{eq} - r_c)}/{r_c}\right]} \qquad \text{(eq. 4)}$$

C: single-phase capacitance [F/m];

ε_0: vacuum permittivity [F/m];

d_{eq}: equivalent distance between phases [m].

And:

$$L = \frac{\mu_0}{8\pi}\left\{1 + 4\ln\left[{(d_{eq} - r_c)}/{r_c}\right]\right\} \qquad \text{(eq. 5)}$$

L: single-phase inductance [H/m].

In which:

$$d_{eq} = \sqrt[3]{(d_{ab}.d_{bc}.d_{ca})} \qquad \text{(eq. 6)}$$

d_{ab}, d_{bc}, d_{ca}: distances between phases [m].

These equations are valid for isolated three-phase circuits. However, in the case of two or more parallel circuits allocated on the same towers, magnetic interaction exists and this phenomenon must be considered in the quantification of these parameters.

In UGCs, the capacitance and inductance are respectively:

$$C = \frac{2\pi\varepsilon_0\varepsilon_r}{\ln\left[{r_{sh}}/{r_c}\right]} \qquad \text{(eq. 7)}$$

ε_r: relative permittivity.

And

$$L = \frac{\mu_0}{2\pi} \ln\left({d_{sh}}/{r_c} \right) \quad \text{(eq. 8)}$$

d_{sh}: sheath (insulator + conductor) diameter [m].

From **Equation 7**, it is possible to conclude that materials presenting higher relative permittivity yield to higher charging power. Consequently, plastic materials, such as XLPE (ε_r = 2,3) and PPLP (ε_r = 2,75), are more reliable than oil-filled paper insulation (ε_r = 3,5).[40] The best insulating materials to be engaged are consequently the ones with low relative permittivity and high dielectric strength.

2.4. Fault Level and Power Flow Controls

Representing some of the major constraints in the electrical power systems, as well as being powerful instrument in important fields of research in electrical engineering, the fault level and the power flow controls are accounted since the initial design stage of any power plant, substation or other electrical systems.

While at initial stage calculations are initially resolved to accommodate certain operational practices ensured by appropriate switchgear and interlocking arrangements, considering expansion and changes in the configuration of the system, later modifications in the networks and unexpected load growth, including new connections and power plants, affect the short-circuit rates and the power flow harmony of the system throughout its lifespan.

2.4.1. Fault Level Control in Meshed High-Voltage Systems

Short-circuit levels raise as the installation of new generation, particularly of distributed generation, new feeders, transmission lines and compensation schemes are implemented in the network. Not only the high expenses of the possible refurbishment in the present system or even the construction of additional substations, but also the redesign and test of equipment can extend to a larger portion of the power transmission grid to secure admissible fault levels for the system.[41,42] As result of this, excessively high short-circuit levels can occur to the existing network causing permanent damage (thermal stress) to the UGC insulation. This induces to the replacement of UGCs.

In the depicted test network, underground cables and overhead lines are both employed together and in most occasions as parallel circuits, reflecting the current situation in the typical Finnish urban 110-kV subtransmission networks.[43] **Chapters 3** and **6** describe and debate over the efficiency of the chosen fault current limiting techniques in the technical and economical spheres in the network in study.

2.4.2. Power Flow Control in Meshed High-Voltage Systems

Concomitantly, power flow control involves installed devices to enhance the performance of networks. It is another solution to increase the capacity and eliminate some of the bottlenecks in a network excluding further expansion in the system. Given the topological nature of a network, a variety of strategies are used to reorganize the flow of power, increasing efficiency and capacity of the power grid.

Shifting from the traditionally employed radial structure to the meshed multilateral power grids, the plurality in which the power systems have developed has introduced problems that had not previously been a major issue. One example is the concept of the Smart Grids

(**Figure 9**). The presence of distributed generation, combined heat and power and distributed storage systems (*e.g.*, batteries) in different locations of the network represents a larger degree complexity to the power flow control.[44]

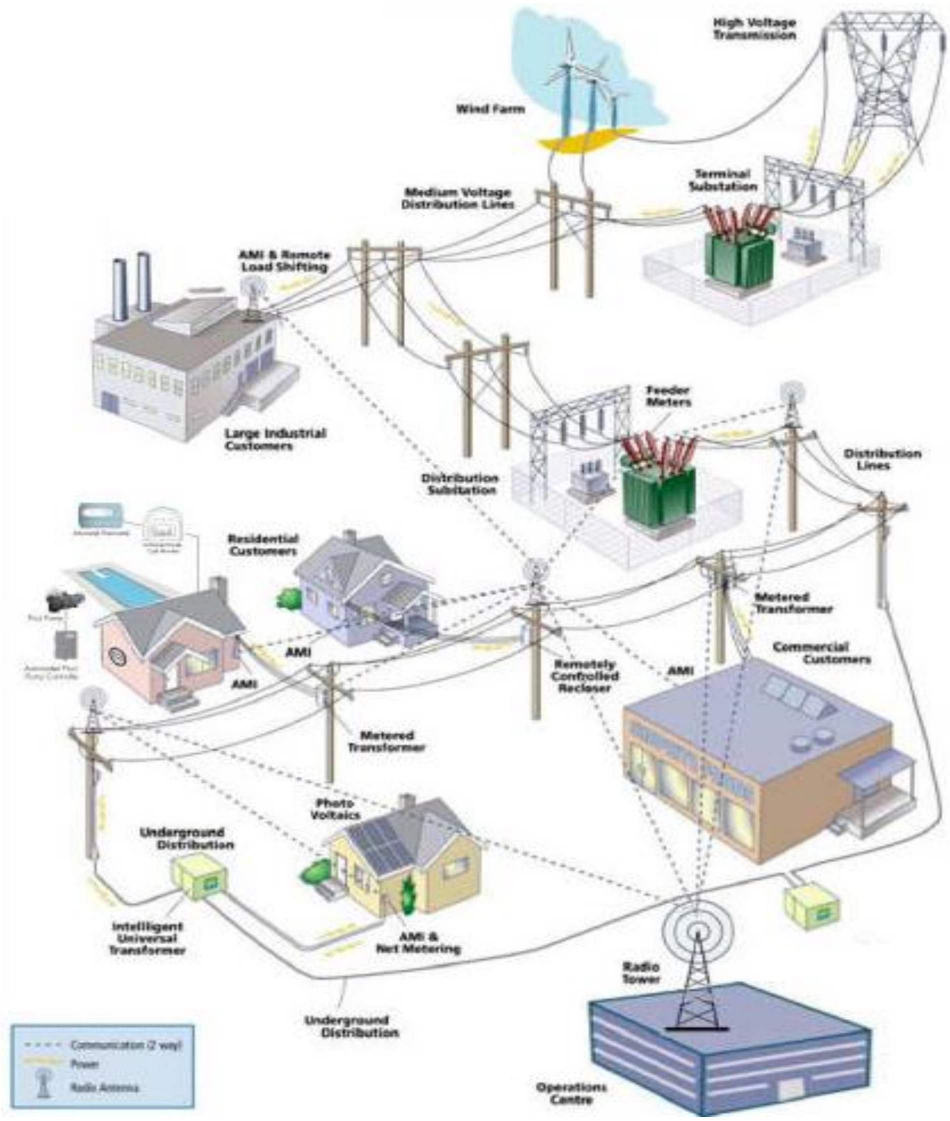


Figure 9: Schematic of a smart grid. It is distinguished by the presence of DG, CHP, distributed storage and enhanced control technologies along the network.[45]

In these new scenarios, it is dramatically more arduous to maintain constant balance between generation and demand to support the integrity of the electricity grid.

Uncontrolled power flow causes overload of lines and transformers, unbalances the delivered power (hence violating contractual power exchange), reduces the security margins in the system as well as increases the fault level. In addition, these inefficiencies lead to greater system losses (such as the cascade feeder tripping), reduced power transfer capacity and opposite reactive power flows.

Power flow is diametrically related to the supply and demand balance. By voltage regulation and control of power in a network, governor mechanisms and voltage regulators depict examples of controlling systems in generation. Further, the division of load between generators determines output power of each machine according economical and operational considerations.

Similarly, on the load side, the correction of power factor suppresses fluctuations from non-linear dynamic loads and maximizes transference of real power from source to load.

At transmission and distribution levels, as a way to improve power quality and increase the network capacity, power flow control is based on voltage support and reactive power compensation, which are intrinsically related. Robust voltage support along the multiple paths of high-voltage systems is mandatory to minimize voltage variations in its terminals, while power compensation sustains optimal efficiency of the grid.

The power transfer through a conductor is represented by these simplified equations:

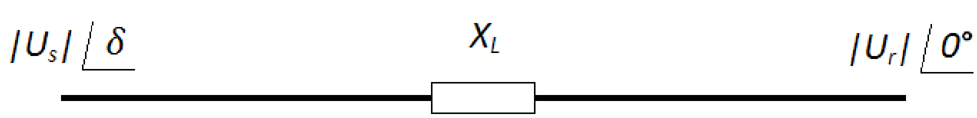


Figure 10: Simplified line diagram.

$$P = \frac{U_s U_r}{X_L} \sin(\delta) \qquad \text{(eq. 9)}$$

$$Q = \frac{U_s U_r}{X_L} \left[\cos(\delta) - \frac{U_r}{U_s}\right] \qquad \text{(eq. 10)}$$

P: active power [W];

Q: reactive power [VAr];

U_S: voltage at sending terminal [V];

U_r: voltage at receiving terminal [V];

X_L: line reactance [Ω];

δ: angle [rad].

Through **Equations 9** and **10**, it is possible to infer that varying the line reactance and the system voltages alter the active and reactive powers through a network. Similarly, power control is also performed by voltage regulation (U_s and U_r) and angle variation (δ) using different devices and solutions.

Conventional technology, using mechanically-switched devices, has been traditionally used to compensate long overhead lines (air-core reactors and static bank of capacitors are classical examples). These lines when fully loaded absorb reactive power. Under light loads, longer lines may present predominantly higher values of shunt capacitance, resulting in generation of reactive power.[46] For this reason, compensation schemes can be classified in two configurations: shunt and series compensation.

The first is employed to modify the equivalent impedance in the terminals of a circuit and the latter is mainly destined to balance load between parallel lines. More complete compensation techniques present both shunt and series compensation. Additionally, most of these traditional devices possess fixed reactance values, representing limited alternatives for subtransmission systems.

More recent technologies, involving consolidated electrical apparatus associated to electronic-based controllers, introduce compensation in a broader sense both in steady-state and dynamic operation. They respond faster and present no moving parts, such as mechanical switches, to perform controllability (due to the static nature of these devices).[47] The term Flexible AC Transmission Systems (FACTS) is attributed to these devices. This topic is further developed in **Chapter 3**.

Chapter 3: Technologies & Techniques under Focus

3.1. Fault Current Limiting Techniques

Mitigating solutions to support fault current limitation have been a plentiful resource of ideas for research and development of techniques and technologies in the power systems. The calculation of the maximum permissible fault current represents economy in the total cost of equipment and material employed in a network as well as possibility of greater penetration of distributed generation. Notwithstanding these operational benefits, limiting fault currents increases main equipment lifespan, such as transformers, cables and lines, as consequence of limited let-through currents.

It is possible to classify these alternatives in two main categories: the short-term, which includes temporary solutions, related to the protection coordination; and the long-term, which comprises modifications in the network that will change its nature and will last for longer period. Some of them are:[48-55]

3.1.1. Short-Term Solutions

I. Remote disconnections:

It is the sequential disconnection of transmission lines, loads or synchronous compensators. This maneuver limits the contribution of these sources, thus limiting current levels. Despite of that, the sequential network tripping (SNT) might represent complex control strategies.

II. Radialization of the network:

By operating strategic circuit breakers during faults by fast-switching mode, the system can shift from meshed or looped to radial configuration. The short-circuit contribution from different sources upstream the fault is limited as a result. This maneuver is operated by fast-switching schemes.

3.1.2. Long-Term Solutions

I. Network topology:

It consists in the alteration of the topology of the targeted system. Splitting the network in different points, such as dividing busbars in one or more points, and opening loops are typical examples.

The utilization of more traditional and less costly solutions, such as this technique, may suit well in some cases; however, reliability analysis, aligned with impact study on the network, represents a powerful tool to identify the efficiency of this alternative.

II. Change in the earthing scheme of transformers:

Inserting or eliminating impedance from the earthing of transformers change the zero-sequence equivalent network, hence decreasing the effects of single-phase faults. This change might not be welcomed in many situations, as in different countries, including Finland, for earthing in different parts of the network is standardized (*e.g.* MV is either neutral isolated or coil earthed).

III. Upgrade or replacement of equipment:

To be adequate to new higher fault current levels in a network, one alternative is to upgrade switchgears, circuit breakers and other equipments to higher ratings. This is frequently resumed as costly and laborious task and is taken into consideration in simpler network topologies, for it avoids more complex coordination schemes.

In contrast, promising technologies – particularly involving fault current limiting devices, such as the fault current limiter (FCL) – have exhibited interesting features to the current needs of modern grids. The concept of unilateral power flow (generation-consumer) is gradually been replaced by more flexible networks with larger capacity, including distributed generation (DG) as well as combined heat & power (CHP) units, covering continental areas.

3.1.3. Fault Current Limiter (FCL)

Another long-term solution is the installation of the fault current limiter. The FCL is the device that operates immediately after a contingency in the grid, such as faults or downed power lines, limiting or reducing unanticipated electrical surges. Depending on the employed technology, FCLs can withstand 20 times the designed steady-state current.[56] Moreover, the operation time of FCLs is smaller than half-cycle, *i.e.*, quick enough to avoid the first current peak.[57] This characterizes the most interesting feature provided by this device, since by limiting short-circuit capacity, mechanical and thermal strain is limited, thus protecting equipment and installations from major damage.[58]

The FCL concept is not new to the power sector. Nonetheless, with the advance of superconducting materials and power electronics, two main classes of FCLs are under development and test: the superconducting (presence of superconducting materials, including high-temperature superconducting technology, HTS) and the non-superconducting (presence of power-electronics-based solid-state components).

In addition to these two classes, older technologies of fault current limiters are also in use, such as I_s-limiters and high-voltage current limiting fuses. These are overcurrent sacrificial devices that must be replaced after operation. The I_s-limiter presents low-resistance and is placed in series with the circuit, frequently it is used as coupling of parallel operation of systems as the short-circuit level at this point increases. In this situation, it segregates the two systems. This device is not considered in this study.[59]

I. Superconducting Technology:[60-65]

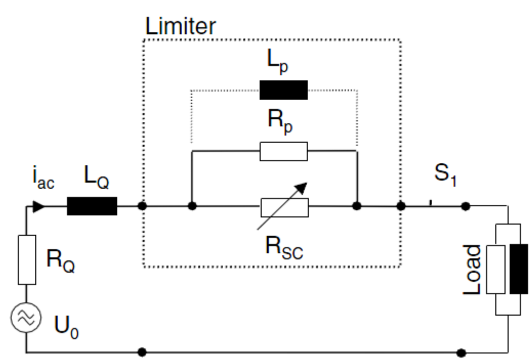
As inferred from the name, this technology is based in superconducting materials, such as stainless steel and Bi-2212 composite. The idea of high-temperature superconductor (HTS) technology, in which T_c = 100 K, is also employed to differ from the low-temperature superconductor (LTS), in which T_c ranges in a few kelvins. The superconducting fault current limiter (SCFCL) can present resistive or inductive state concepts.

The operational principle is very similar for both types of FCLs. SCFCLs under normal network conditions operate as a low-loss resistive (or inductive) load, negligible to the network. Under contingency conditions, after a specified onset current is overlapped, an increasing load (inductive or resistive) is reflected to the network in order to limit the excessive current magnitude from the fault. This transition is often referred as superconductive-to-normal transition (SN) or quench.

After operation, the fault must be isolated and the device experiences a recovery time to cool down and recover after the fault. For that, the device must be equipped with a cryogenic system with liquid N_2 to bring temperature below the system requirement (T_c).

The constructive aspects of resistive SCFCLs are based on wires made of superconducting material that present sharp SN transition behavior. In **Figure 11** (left), the presence of resistance R_p in parallel protects the superconductor from excessive heating during the SN transition, so it is placed along the superconducting material. It is also meant to avoid overvoltages across the device.

The inductive saturable-core FCL consists of two coils, its electric schematic is depicted in **Figure 11** (right). These two coils are placed so that a non-linear reactance is supplied to the network during contingency situation. Under normal operation, one iron coil is kept in saturation by a second superconducting coil. During fault, both coils will be dislocated out of saturation by the high fault currents, hence drastically increasing the apparent coil inductance. During normal operation, the device apparent impedance incorporates low resistance and frequency-dependant inductive reactance.



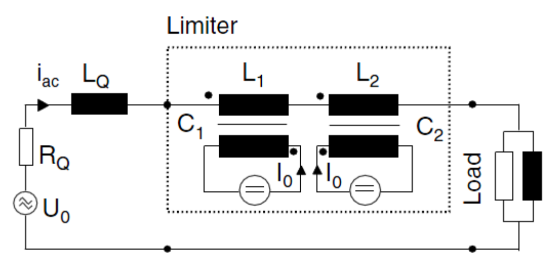


Figure 11: Single-phase diagram of resistive SCFCL (left) and saturated core (inductive) SCFCL (right).[63]

The overall cost of the FCL using superconducting technology can be roughly calculated as the cost of the employed material and varies according the technology in focus.

Further, the cryogenic system and the construction costs must be acknowledged in the estimation for more realistic figure.

II. Solid-State Technology:[66-70]

The solid-state fault current limiter (SSFCL) consists of current limiting bypass impedance (*e.g.*, series reactor), voltage limiting component (such as a metal-oxide varistor, MOV) and a fast power-electronic-based switch, depending on the used technology. Under normal network conditions, current flows through the FCL and under fault conditions, the GTO element switches off, consequently diverting current through the reactor branch.

Additionally, several other technologies are employed in the fault current limitation devices, such as the magnetic fault current limiter (MFCL), superconducting fault current limiting transformers (SFCLT) and so on.

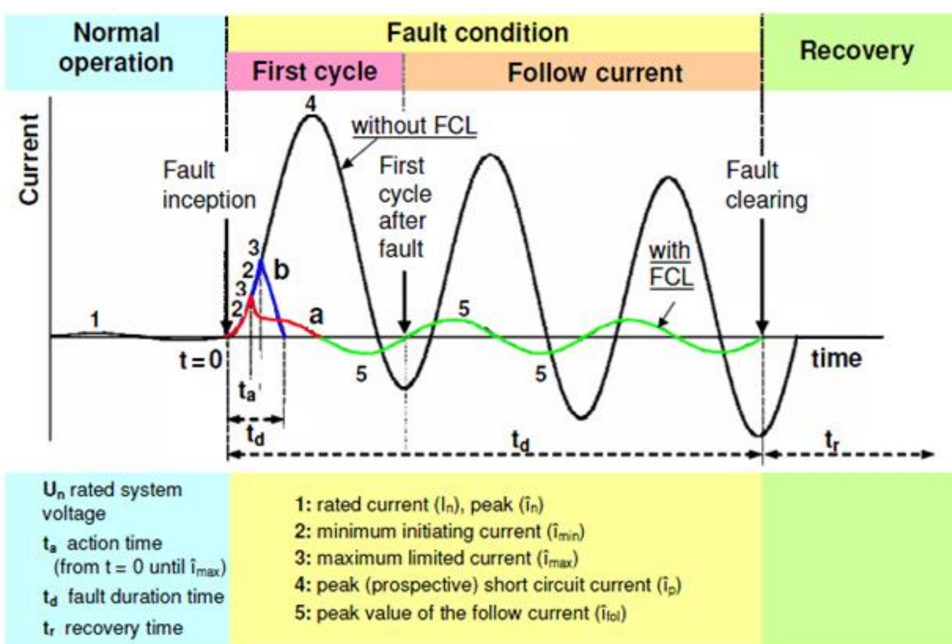


Figure 12: Typical fault current wave shape and date: a) FCL without fault current interruption; and b) FCL with fault current interruption.[71]

The typical behavior of FCLs is shown in **Figure 12**. It is characterized by three operating modes: normal operation, fault condition and recovery. When fault occurs, prior to the first half-cycle, the device is triggered by control schemes or by the SN-transition, injecting the limiting impedance (first cycle). During the fault condition, *i.e.*, the time between the operation of attributed protection in order to sectionalize the circuit and the fault interception, the current is significantly reduced compared to the situation without the device. Alternatively, the system has to be recovered because of the thermal stress, leading to isolation from the system after the fault is cleared.[72] Depending on the superconductive material employed, this recovery time range from seconds to few minutes.[62]

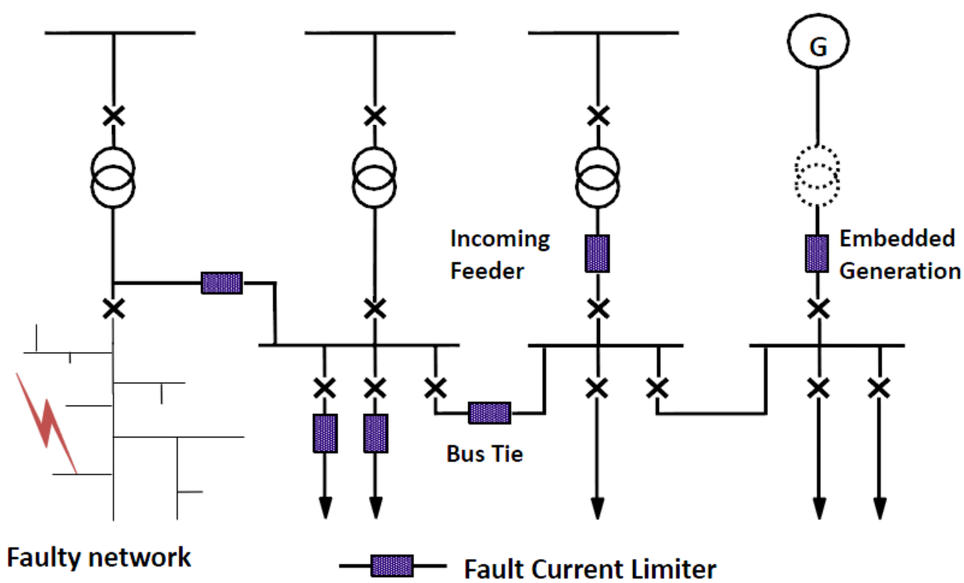


Figure 13: Possible locations of FCLs are, for example, bus-ties, feeders, distributed generation and between substations.[73]

Fault current limiters can be installed at several locations of a network, in which applications represent major advantages (*vide* **Figure 13**). The most suitable zone to apply the

FCL is between the largest source and load, as it is straightforward strategy in purely radial networks. Likewise, this device can be installed at ring-bus and double-bus topology as well.[74] FCL can also be introduced in a system as the increasing integration of distributed generation to the existing network.[75,76] In distributed generation, when new generation units are integrated to the system, short-circuit levels in the connection points raise significantly.[77]

By allocating FCL in bus-ties and in the coupling of two systems, system flexibility is increased and equipment upgrading (such as transformers and circuit breakers) can be avoided, thereby, decreasing costs. Also, coupling adjacent networks foment higher power quality, smaller voltage sags and lower system losses, as paralleled transformers could operate at lighter load.[78]

According to the review published in 2009 by Neumann,[78] and in 2010, by Kirsten,[73] at high voltage levels, American Electric Power is testing a 138-kV 1300-A_{RMS} FCL based on superconducting material in Tidd substation, in Steubenville (USA). In this project, the fault level is reduced by 50% and recovery happens under load.

Despite utilization of FCL within a network, still protection coordination schemes and devices are mandatory in order to ensure proper selectivity to the system. Appropriate coordination and pick-up values are indispensable to distinguish load current from contingency situations.[57]

It is wise to express, whatsoever, that given an existing network the short-circuit rates in buses are altered when the network configuration is modified and when generation is changed (in case of growth of demand). This is represented by installation or deactivation of power unities (as for the example of urban areas in Europe, many obsolete CHPs will be probably deactivated, replaced or repowered by more modern facilities in the next few decades), topology changes or alteration of load types (installation of synchronous machines to the network).

Installing FCLs only limit temporarily the fault levels during contingency in order to protect equipment from thermal and mechanical stress while fault is not cleared or sectionalized. It does not eliminate faults, but softens effects under different fault types (unsymmetrical and symmetrical). This feature is advantageous to networks and enlarges lifespan of associated line equipment. It is also imperative to accredit that, as any equipment, its reliability rate is not absolute, being susceptible to failure and unavailability (maintenance, technical issues and so on), and the FCL must be properly integrated with the network protection system.

3.2. Power Flow Control Techniques

In urban subtransmission systems, such as the considered in this thesis, lines and cables present relatively short length and meshed topology. Acknowledging this environment, compensation aims to provide optimal parallel operation of UGC and OHL to achieve minimal losses and balance impedance.

In some cases depending on network design, after line interruption, feeders might suffer cascading line tripping due to line congestion, leading to generalized system loss. In order to balance this problem, compensation enacts as a solution to improve underutilized and congested lines. Some examples of compensation methods used in subtransmission networks are:

3.2.1. Conventional Technologies

I. Phase-shift transformer (PST):[79]

The PST is type of transformer that alters the active power flow between two systems. It can be interpreted as modification in the power angle of **Equations 9** and **10** (**Chapter 2**), *i.e.*, by inserting a phase-shift. There are mainly three types of PSTs: direct, indirect and asymmetrical.

The first type includes one three-phase core by which the phase shift is obtained from the appropriate winding connections. The second type of PST is compound by two transformers, one shunt tap exciter to control voltage and other in series to inject voltage. Finally the third, the asymmetrical PST induces angle and amplitude altered values of voltage in its terminals. This transformer is allocated in parallel circuits with different capacities (*e.g.* OHL and UGC). By manipulating the phase angle, currents through conductors are rearranged to more favorable paths to relieve overloads in the system. This technology was not considered in this simulation.

II. Passive compensation:[80,81]

This method introduces passive electrical components (reactor and capacitor bank) in the system to provide voltage control and reactive compensation. These elements can be placed either in series or in parallel with a circuit.

Shunt reactors (inductor) are inserted permanently to EHV busbar to compensate the capacitive effects of long transmission lines, usually over 200 km. Shunt capacitors are utilized throughout the system to supply reactive power (boosting local voltage) during heavy loading conditions. This represents a wide-spread alternative as a consequence of its low cost and flexibility of installation and operation.

In series, capacitors are connected to conductors to compensate inductive reactance. This is mainly introduced to improve system stability and to acquire balanced load division between parallel lines. And finally, series reactors are commonly installed in high voltage systems to limit fault current levels and to distribute power more homogeneously in the case of parallel UGC and OHL. This happens by increasing equivalent reactance in a circuit. It is the most economically viable of the compensation techniques, costing between 10 and 20 dollars per kVAr; however, power losses are high owing to the resistive components of coil and voltage drop across the reactor can be considerably high.

3.2.2. Flexible AC Transmission System Devices (FACTS)

FACTS device is defined by the IEEE as "a power electronic based system and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability".[82] FACTS controllers steer current in a line through fast controlling of the voltage or modifying the impedance of the system. Power flow control in an under-utilized line happens by enhancing voltage locally, and as a consequence, allowing additional current to be injected into this line.

Table 4: Overview of conventional and recent technologies applied to AC systems.[47]

	conventional (switched)	**FACTS-Devices** (fast, static)	
	R, L, C, Transformer	Thyristorvalve	Voltage Source Converter (VSC)
Shunt-Devices	Switched Shunt-Compensation (L,C)	Static Var Compensator (SVC)	Static Synchronous Compensator (STATCOM)
Series-Devices	(Switched) Series-Compensation (L,C)	Thyristor Controlled Series Compensator (TCSC)	Static Synchronous Series Compensator (SSSC)
Shunt & Series-Devices	Phase Shifting Transformer	Dynamic Flow Controller (DFC)	Unified / Interline Power Flow Controller (UPFC/ IPFC)

In congested networks, FACTS devices increment impedance in the problematic line, thereby pushing excess of current into adjacent paths. These controllers provide rapid operation and can continuously inject reactive power into the system. Altogether, these effects lead to the growth of the system capacity and line utilization. The major FACTS devices are related in **Table 4** that compares different FACTS with conventional switched technologies in three possible configurations.

FACTS controllers insert larger degree of freedom to the present power systems operation and management by being able to adjust parameters independently so as to control power flow.[83] These devices, notwithstanding the technology employed, permit a wide spectrum of impacts on a network, most related to voltage support and optimized power flow. In addition, FACTS devices can minimize power damp oscillations, enhance transfer capacity of power and provide stability and power quality improvements.

The correct dimensioning of these devices and most effective positioning in the system must be evaluated to achieve optimal operation. This is subject of study for several researches investigating equipment reliability, developing algorithms for optimized transmission capacity and best allocation point using different FACTS technology as well as other compensation techniques.[84-91]

I. Thyristor-Controlled Series Capacitor:

The FACTS controller utilized in this work is the thyristor-controlled series capacitor (TCSC).[92-94] This class of FACTS consists in a controlled inductor positioned in parallel with a capacitor bank (**Figure 14**). In this configuration, it is permissible to rapidly control the degree of compensation and to tune the fundamental frequency of the capacitor bank. Decreasing the equivalent reactance in the line leads to mitigation of power oscillation damping (POD), subsynchronous resonance (SSR) and mitigation of voltage sags.[95] It has been investigated the usage of TCSC as fault current limiter.[92]

The main structure of a TCSC is based on a compensating capacitor, a bypass inductance, thyristor valve and a MOV connected across the capacitor. The operation of the device is divided in four modes: blocking, bypass, capacitive boost and inductive boost. In *bypass mode*, the thyristorized valve is not triggered, so the TCSC operates as a fixed series capacitor. During the referred mode, the valve is triggered activating the inductor and the result is an inductor and capacitor in parallel. In *capacitor boost mode* (or the normal mode), the capacitor discharges proportionally increasing the fundamental voltage. And finally, the *inductive boost mode* is characterized by the increase of the circulating current and the voltage distorted waveform. This creates increase of the line inductance.

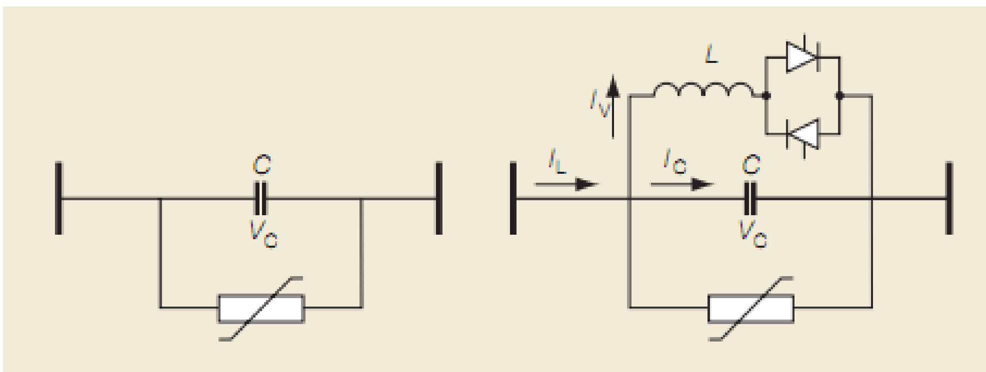


Figure 14: Typical series compensation: series capacitor (left) and TCSC (right).[96]

It is practice that for series capacitors the compensation factor, the ratio between compensation capacitive reactance and the line inductive capacitance is between 30% and 70%. In addition, it is usual that from 70% to 90% of compensation is introduced by fixed series capacitor and from 10% to 30% by TCSC. In this way, the cost of compensation arrangement is decreased without commit performance and flexibility in the system.

According to Khederzadeh,[92] keeping constant all parameters and inserting 50% of compensation, steady-state transferred power doubles, for 75% of compensation, power transfer increases fourfold in series capacitive compensation. Furthermore, typical location of series capacitors is on the mid-point of the HV line or in both extremes of the line.[97] The location directly affects the effectiveness of compensation and the voltage profile along the line.

Several considerations ought to be accounted when it comes to the choice of the utilized techniques. The costs attributed to these solutions represent a major driving factor. FACTS devices, as a new technology and presenting expensive components, are drastically more expensive than traditional alternatives; on the other hand, older technologies, such as capacitor banks and series reactors, have been under operation for the last decades possessing well-known drawbacks and relatively low operational costs.

The most suitable locations for the installation of the above mentioned compensation techniques has to be determined, considering accessibility, power transfer effectiveness (choice of the “weakest” bar in the network, generated by power flow simulations) and fault levels. Additionally, technical and operational aspects are determinative in the choice of the most suitable device. Compatibility with other equipment and protection philosophy has to be ascertained before installation of any compensation device.

3.3. Upgrading Feeders

Upgrade existing cables and lines can be a realistic alternative to modernize, improve system capacity and provide better compatibility with existing network. By the end of a network lifespan, systems with obsolete technology have to be substituted by more recent technology and replaced by more robust conductors, for example, underground cables presenting improved insulation and better ampacity.

In some situations, upgrading a feeder with all associated equipment and ancillary systems might be as costly as building new feeders. The access to the network in underground tunnels or in densely populated areas can result in huge operational obstacles for the installation. However, particularly in congested metropolitan areas, this comprises the only alternative to expand and improve capacity of a network.

In this current study, the upgrade of underground cables is assessed and compared with the other described solutions. Simplifications were assumed in order to quantify costs and maintenance services. Further explanation is detailed in **Chapter 4**.

Chapter 4: Reliability Analysis & Cost Functions

4.1. Reliability Analysis

Reliability is a commonly attributed term in the power systems to define the continuity of service to the end customers. Further, it is one essential element in the analysis of power supplied to a network. In order to be a reliable system (*i.e.*, the one that provides electricity without interruptions), it is mandatory that the utility offer sufficient power, satisfactory quality (robust voltage, frequency and active/reactive power profiles) under continuous availability. This is a practically impossible task; however, to assure a 100% secure supply, as in hospitals or data centers, own backup generation has to be installed to support the system against loss of supplies.[98]

The failure of part of a network is termed outage. This can be caused by a unexpected event (contingency), such as rough weather conditions, faults, or predicted and planned circumstances. The relationship between equipment failure and service interruptions caused by outage is identified as a central issue to be dealt in the reliability analysis. In addition, outages cause interruptions to the end customers and these interruptions are characterized by the frequency (how often) and the duration (for how long) that they happen, as the result of service problems in the system.

Outage can be classified in 3 different types: *expected*, anticipated equipment or conductor failure; *forced*, not predicted equipment or conductor failure as a consequence of damage or accident, therefore inducing forced withdrawn from network; and *scheduled*, scheduled outage for the matters of maintenance or substitution of equipment. Similarly, interruptions are grouped as: *instantaneous*, restored instantly by automatic equipment, typically lasting less than 15 seconds; *momentary*, restored by automatic or manual switching in site, typically less than 3 minutes; *temporary*, restored by manual switching when operator is not available, typically 30 minutes; and *sustained*, longer lasting interruptions taking longer than one hour.[99]

In this thesis, the studied subtransmission network is evaluated according to the qualitative (N-1)-criterion. To accomplish this criterion, a network must, in whatsoever technically possible scenario, support failure of part of the system without suspending or restricting power supply.[100] This is followed so that a high level of reliability of the system is achieved to benefit the customer. Moreover, the focused network presents redundancy in the number of transformers and double circuits and double busbars in case of failure.[101]

Consequently, larger investments from the utility party must be introduced to avoid low level of reliability that causes costs to the customer party. In addition, different network topologies are investigated given short-circuit levels, reactive balance, voltage profile, power losses and economical feasibility. Comparisons at distribution levels have been exploited to support this study.[102,103]

4.1.1. Reliability Factors

In a network, all equipment and components are susceptible to failure due to technical problems, accidents due to third parties, weather conditions and so on. For that, the main factors employed to assess network reliability are:[2,98,99,101-113]

I. Radially Operated Networks:

Average outage rate:

$$\lambda_j = \sum_{i \in \mathbb{N}}^{n} \lambda_i \qquad \text{(eq.11)}$$

Annual outage time:

$$U_j = \sum_{i \in \mathbb{N}}^{n} \lambda_i t_{ij} \qquad \text{(eq.12)}$$

Average outage duration:

$$r_j = \frac{U_j}{\lambda_j} \qquad \text{(eq.13)}$$

Non-distributed energy (NDE):

$$E_j = \lambda_j r_j P_j \qquad \text{(eq.14)}$$

λ_j: average failure rate for load j [failure/a];

n: number of feeder sections;

U_j: annual unavailability for load j [h];

t_{ij}: outage time at load point j caused by failure in component i [h];

r_j: average outage duration for load j [h];

E_j: non-distributed energy to load j [kWh].

II. Parallel Networks (Two Circuits in Parallel):

Average outage rate:

$$\lambda_p = \lambda_1 \lambda_2 (r_1 + r_2) \qquad \text{(eq.15)}$$

Annual outage time:

$$U_p = \lambda_1 \lambda_2 r_1 r_2 \qquad \text{(eq.16)}$$

Average outage duration:

$$r_p = \frac{r_1 r_2}{r_1 + r_2} \qquad \text{(eq.17)}$$

Index "*p*", "*1*" and "*2*" meaning, respectively, "parallel", "circuit 1" and "circuit 2".

In addition to these equations, it is possible to derive relations for the situations when a permanent interruption overlaps maintenance interruption, a temporary interruption overlaps maintenance, a permanent interruption overlaps temporary and *vice-versa*.

4.1.2. Reliability Indices

Some indices are broadly employed in reliability analysis, representing a statistical aggregation, given determined value of load or consumers. SAIDI (system average interruption duration index), SAIFI (system average interruption frequency index), CAIDI (customer average interruption duration index) and CAIFI (customer average interruption frequency index) are examples of them.[98,99,114-116]

These parameters do not classify connected loads by peak demand, size or sales. Alternatively, "*n*" interruptions throughout a period of time, usually *per* year, to a single customer, or "*n*" simultaneous interruptions to different customers are considered as "*n*" interruptions of service. These customer-based indices regard small consumers to be as important as large ones.

Analytically:

$$SAIFI = \frac{\sum N_i}{N_T} \tag{eq.18}$$

$$SAIDI = \frac{\sum r_i N_i}{N_T} \tag{eq.19}$$

$$CAIDI = \frac{\sum r_i N_i}{\sum N_i} \tag{eq.20}$$

$$CAIFI = \frac{\sum N_i}{CN} \tag{eq.21}$$

N_i: number of customers interrupted;

N_T: total number of customers;

r_i: restoration time for interruption event [h];

CN: total number of customers experiencing interruption.

4.2. Cost Composition

Returning the total cost of a project, a general function can be expressed as:

$$C_{total} = \sum(C_{inv} + C_{loss} + C_{o\&m} + C_{out}) \tag{eq. 22}$$

C_{total}: total network cost [€];

C_{inv}: investment cost [€];

C_{loss}: loss cost [€];

$C_{o\&m}$: operation and maintenance cost [€];

C_{out}: outage cost [€].

This function is typically employed to transmission and distribution components, lines, substations and switches. Additionally, the total cost of a component in the network under focus is a function dependent on the lifespan, load type, load growth rate and interests over the revision time. Values utilized are exhibited in **Appendices B**, **C** and **D**.

The cost components, in this current reliability investigation, include capital expenditure (Capex), losses, operational expenditure (Opex) and outage cost, as described below:

I. Capital Expenditure (Capex):[2,117,118]

Capex comprises the funds utilized to purchase or upgrade physical fixed assets (*e.g.* equipment). This value is integrally capitalized in the year of the expense as investment. Alternatively, it can, as well, be amortized over a time period. The construction (earthwork, cable channels and pipes, erection of towers and materials) and conductor price were considered in underground cables and overhead lines investment. For other equipment, such as circuit breakers and compensation schemes, estimative was held, accounting main device price and station or price per kVA or unit. In the case of the FCL, the price considers the cost of the amount of material employed in its design.

II. Losses:[2]

This component is included within the running cost category. It is the value that considers market price for energy and marginal price at different voltage levels (in the case of this study, subtransmission level).

III. Operational Expenditure (Opex):[2,117]

Also computed as running costs or maintenance costs in the considered systems, it is small compared to the investment of equipment, ranging 0,1% to 0,8% in primary equipment (transformers, conductors) and from 1,5% to 2,5% in secondary equipment (automation and ancillary services).

IV. Outage cost: [15,119]

This consists of the cost of outage, regarding the customer interruption cost (CIC) and repair costs. Further, it accounts the energy not supplied to the load. The outage cost component is significantly higher compared to electricity prices, augmenting the necessity of a robust and more reliable network. In this study, the effect of faults at transmission level was kept aside, since it might cause lack of supply to the totality of the load comprising an absurdly high value. In addition, faults at transmission level are considerably fewer than at subtransmission and distribution levels, particularly three-phase faults.

4.2.1. Comprehensive Cost Function in this Model

It is practical to model a network in this type of study considering a lifetime between 30 to 40 years. Further, primary components, such as transformers, can have a lifespan from 30 to 50 years.[2] Load is identified by load growth rate, electric characteristics of load, peak utilization time in the first year and type of customers connected. In several cases, the load growth and interests are considered either homogeneous through the considered revision time or constant during the first half of the considered revision time and invariable during the second half.

In this thesis, the cost function is based exclusively on the feeder cost and attributed equipment and protection failure effects, to try to quantify and compare the event of changes in compensation schemes and fault current limiting techniques on the cost of each feeder section.

The total cost calculated accredits conductor choice, 2 circuit breakers per feeder, maintenance or circuit breakers and conductors, compensation scheme costs (when present), equipment failure rate (busbars, conductor, circuit breakers and transformers) and outage (fault-repair and customer interruption costs). From **Equation 22**, it can be developed to the following equation for the network under consideration:

$$C_t = \sum_{i=1}^{n} \big[(C_{cd} + C_{cb} + C_{cp})_{inv} + (C_{cd} + C_{cb} + C_{cp})_{o\&m} + C_{loss} + (C_{cd_r} + C_{eq_r} + C_{CIC})_{out}\big]_i \qquad \text{(eq.23)}$$

C_t: total cost *per* feeder section [€];

C_{cd}: conductor (and attributed services) cost [€];

C_{cb}: circuit breaker cost [€];

C_{cp}: compensation scheme (in case it is used) cost [€];

C_{cd_r}: conductor repair cost [€];

C_{eq_r}: equipment (busbar, transformer & circuit breaker) repair cost [€];

C_{CIC}: customer interruption cost [€].

In which:

$$C_{loss} = k_{loss}.\,h_{wk} T_{peak} P_{loss} \qquad \text{(eq.24)}$$

And:

$$C_{CIC} = k_{load}\lambda[a(t) + b(t).T_{out}]P_{ns} \qquad \text{(eq.25)}$$

k_{loss}: discount factor for loss-related costs;

h_{wk}: load loss price [€/kWh];

T_{peak}: annual peak utilization time [h/a];

P_{loss}: power loss [kW];

k_{load}: discount factor for load-related costs;

λ: average failure rate [failure/a];

$a(t)$: cost *per* unit of power not supplied *per* interruption [€/kW];

$b(t)$: cost *per* unit of energy not supplied *per* interruption [€/kWh];

T_{out}: average outage time per equipment/line section [h];

P_{ns}: power not supplied [kW].

4.2.2. Discount Factors

In order to evaluate cash flow at different moments attributing time value of money, the economic assessment must include time as a dependent variable. As a consequence, the idea of present value – or present worth – is introduced and is the sum of cash produced by an invested capital given an interest rate (*per* year) at a given time (in years). It is quantified in accordance to:

$$S_t = S_0.(1 + p/100)^t \qquad \text{(eq.26)}$$

Similarly:

$$S_0 = S_t.\frac{1}{(1 + p/100)^t} \qquad \text{(eq.27)}$$

And:

$$\alpha = \frac{1}{(1+p/100)^t} = \frac{1}{\delta^t}$$

S_t: present value [€];

S_0: initial value (investment) [€];

p: annual interest rate [%];

t: year posterior to investment;

α: present worth factor;

The first discount factor (k_c) is the averaged annual value over the load growth time. The second (k_l or k_{load}) is employed in situations that there must be linear connection with load growth (*e.g.*, outage costs). And the third (k_q or k_{loss}) is attributed to situations in which quadratic relation is demanded (*e.g.*, losses calculations of cost, for copper losses are quadratically proportional to current).

These 3 figures are represented as, respectively (formulation is developed in **Appendix E**):

$$k_c = \frac{1}{p/100} \cdot \left[1 - \frac{1}{\delta^T}\right] \qquad \text{(eq.28)}$$

$$k_l = \gamma_1 \left(\frac{\gamma_1^{t\prime} - 1}{\gamma_1 - 1}\right) + \gamma_1^t . \gamma \left(\frac{\gamma^{T-t\prime} - 1}{\gamma - 1}\right) \qquad \text{(eq.29)}$$

$$k_q = \gamma_2 \left(\frac{\gamma_2^{t\prime} - 1}{\gamma_2 - 1}\right) + \gamma_2^t . \gamma \left(\frac{\gamma^{T-t\prime} - 1}{\gamma - 1}\right) \qquad \text{(eq.30)}$$

In which:

$$\gamma_0 = \frac{1}{(1 + p/100)}$$

$$\gamma_1 = \frac{(1 + r/100)}{(1 + p/100)}$$

$$\gamma_2 = \frac{(1 + r/100)^2}{(1 + p/100)}$$

k_c: discount factor for constant relation with load growth;

k_c: discount factor for linear relation with load growth;

k_c: discount factor for quadratic relation with load growth;

r: annual load growth [%];

T: load growth period;

t': review year.

4.3. Approximations and Considerations

It is imperative to assume approximations for the model in order to assess the network under focus. Firstly, there must be linear approximations of the cost curves for underground cables and overhead lines (presented in **Appendix F**). This simplification is necessary, so that load can be placed at any point of the network, owing quadratic relation to the loss-load.[114]

Secondly, the two loads are identical, as well as the two 110/20 kV transformers and the two 400/110 kV transformers. In case of interruption originated by overload, the loads are not disconnected from the grid in totality. Each load (equivalent model) is evenly divided into ten feeders. Under this circumstance, these feeders are disconnected one-by-one until the system is relieved and overload is suppressed.

Thirdly, as previously mentioned, faults originating in transmission networks are considered separately. This occurs because interruption at this part of the power systems causes total interruption of supply to consumers, inserting very high costs to the network. As the focus of this work is to analyze different techniques and since in whichever case under test, they will be connected to the same modeled transmission network, the frequency of contingencies and result of outage (total power interruption) will be the same for all simulated cases.

In addition to short-circuit levels at busbars and power flows in the test-network, other factors are also considered, such as aging mechanisms in the network infrastructure, thermal effect in equipment, voltage drop and voltage sags.

4.3.1. Aging Infrastructure

Issues related to aging infrastructure in the power systems introduce critical factors in terms of reliability and damage. For this reason, more thorough analysis and considerations must be accounted for, such as increasing likelihood of failure, increase of maintenance costs and problems with spare replaceable parts.

Similarly, as different equipment is installed to the system through a wide span of time, old equipment that might be technologically obsolete presents problems related to compatibility with newer technologies, thus causing additional costs to the overall project.[114]

4.3.2. Thermal Effect

Insulation of electrical equipment, such as transformers and cables, is subject to exponentially increasing failure rates as a result of thermal effects caused by insufficient mechanical and electrical insulation strength.[114] This conclusion was empirically determined through experimental tests and by the acquisition of equipment age profiles, summarizing the situation.

In UGC and transformer insulation, the most important thermal aging factors that accelerate the process are temperature and the presence of water vapor (in some environments, such as nuclear power plants, radiation performs strong factor).[120,121] Conversely, the thermal effect and aging mechanisms do not affect overhead lines at the same degree of intensity as in underground cables, despite the possibility of conductor corrosion.

4.3.3. Voltage Drop and Voltage Sag

Voltage and frequency profiles are standardized as warranty of power quality provided to consumers.[122] Voltage drop depends on load currents and conductor and transformer impedances. Acceptable values for voltage drops from voltage source to connection point must be within 10%-limit.

Voltage drop is obtained from the following formula (for lagging power factor, *i.e.*, $0° \leq \phi \leq 90°$):

$$\Delta V = \sqrt{3} I [R \cos(\phi) + X \sin(\phi)] \qquad \text{(eq.31)}$$

ΔV: voltage drop [kV];

I: line current [A];

R: resistance [Ω];

X: reactance [Ω];

ϕ: angle from power factor [degree].

According to regulation,[123] a 10-minute voltage variation should be within 10% (0,9 to 1,1 pu) of tolerance in 95% of a week and within 85 and 110% of tolerance all the time. Following this, the maximum voltage drop allowed in this simulation is 2% for the subtransmission network in this simulation.

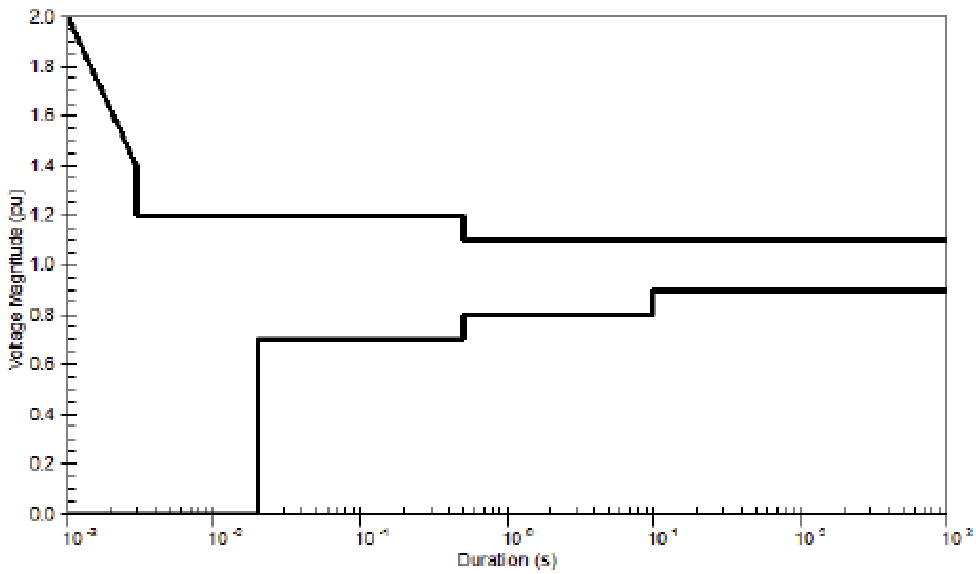


Figure 15: Voltage tolerance profile.[107,124]

Voltage sag is typically caused by faults at all power system levels and is propagated through the power system.[15] It is characterized as a sudden reduction of the supply voltage to a value between 1% and 90% followed by recovery after a short period (0,5 cycle to 1 minute).[123,124] Further, in **Figure 15**, a voltage tolerance envelope can be identified, in which the region above the upper curve is denominated “prohibited region”, under the lower curve is the “no damage region” and between both curves is attributed as the “no interruption region”.

Chapter 5: Network Simulation

5.1. Simulations

The design of networks, from the electrical engineering point of view, includes studies of voltage level selection, power flow requirements, system stability performance, voltage and power flow control at the selected voltage level, conductor selection, loss simulation, short-circuit simulations, corona-related performance, electromagnetic fields effects, insulation design, appropriate switching and protective arrangements. Concomitantly, economic inspection and viability of the project are investigated in order to provide the best solution, acknowledging the previously mentioned factors. Furthermore, several different studies and factors must be regarded involving different fields and competencies, such as environmental and logistic factors.

In this simulation, given the subtransmission voltage level, technical and operational aspects of this network, the economic assessment, power flow and short-circuit level analysis are interpreted as vehicles to provide the most plausible alternative for existing 110-kV meshed networks. Therefore, reliability and operational advantages, economic viability (the least expensive solutions), least number of interruptions to customers and most straightforward modifications in the existing network were the four pivotal factors regarded in this study.

It is important to highlight that this study does not intend to judge or criticize any technology in its focus, whatsoever. In fact, it intends to offer input in order to compare a variety of cases; in each case, these techniques have either been extensively employed in power systems over the decades, presenting a substantial number of advantages in a variety of applications, or are under improvement/test.

The simulations were held in two sets of tests: first, the network cases (depicted in **Figures 16** and **17**); and second, the test network (depicted in **Figure 2**).

5.1.1. Simulation, Part I - The Network Cases

Accordingly, several cases, utilizing the previously described techniques and technologies, were analyzed in comparison to “base cases”. The base case is the one from which all other cases derive. For instance, the “radial base case” is the existing fictional network to be compared to the other radial network cases (with various combinations of conductors). The analysis of different alternatives can be accomplished by direct comparison. Naturally, the existence of more conductors represents higher investment costs as well as the presence of increasing length of underground cables in the network.

52 different networks were investigated in this study. They were divided into two test groups: network configuration, the first 25 simulation cases; and installed equipment/device, the following 27 simulation cases. The first group comprises of different networks, according to topology (radial, looped and meshed). The latter includes installation of devices, equipment or modification in the base cases (split busbars and upgrading existing underground cables).

In this part of the simulation, the used parameters were selected to create a limit situation in which cables and lines within the load-growth time of 40 years are close to their maximum capacity (in some cases, overload condition was introduced intentionally within this period to verify effectiveness of the employed techniques). The transformer ratings, network impedance and chosen bases (power and voltage) were chosen in a way that they do not represent any limiting factor in the analysis of the power flow behavior in the conductors of the network cases. Also, the number of conductor sections varied between four and eight in the tested cases. For that, normalized values given in €/km were obtained to provide feasible tool of comparison between the fifty two networks.

This first simulation was performed as the following:

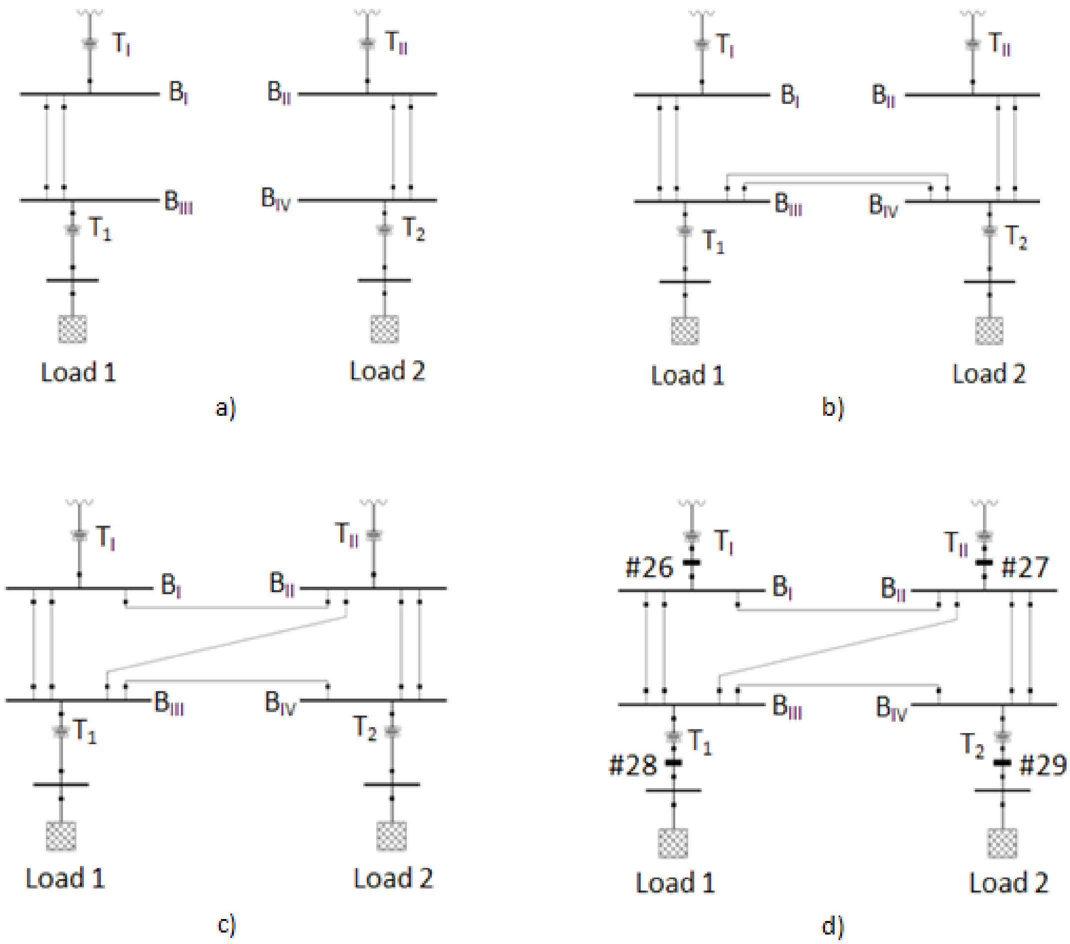


Figure 16: Network cases: a) radial; b) looped; c) meshed; and d) FCL.

I. Radial Network Configuration (cases #1, #4 - #7):

(**Figure 16a**) Several combinations of UGCs and OHLs are tested in this subgroup on radial topology and they are compared to base-case #1. It was inspected the effect of different numbers of parallel conductors (from 1 to 4 conductors connecting two busbars) in the network power flow distribution;

II. Looped Network Configuration (cases #2, #8 - #15):

(**Figure 16b**) Combinations of UGCs and OHLs in looped configurations are employed in this subgroup (base-case #2). Open-loop and close-loop topologies were simulated by varying the number of parallel conductors.

It is imperative to recognize the fact that this configuration places the HV transformers in parallel (parallel operation of transformers T_1 and T_2). In this case, for satisfactory operation, avoiding circulation of currents between them and their subsequent damage, parallel operation requires: identical voltage ratio, identical per-unit impedance, same polarity, same phase sequence and identical zero relative phase displacement;

III. Meshed Network Configuration (cases #3, #16 - #25):

(**Figure 16c**) In this simulation group, UGCs and OHLs are employed in several meshed configurations (base-case #3) using six to eight conductor sections;

IV. Installed FCL (cases #26 - #29):

(**Figure 16d**) In these four cases, FCLs are installed in different parts of network, both in the 110-kV and 20-kV side (base case is #22, for it has the same configuration except the presence of this device). The FCL employed is a resistive 110-kV SCFCL (as a similar model in

138 kV in the United States has been developed and is under testing phase) and the equivalent equipment for 20 kV. Four different values of resistance were used in the calculations at 110 kV (cases #26 and #27): 5 Ω, 10 Ω, 20 Ω and 50 Ω. Additionally, the equivalent values were simulated at the voltage level of 20 kV (cases #28 and #29). In **Figure 16d**, it is possible to identify the employed allocation of the FCLs.

The device locations were: between busbar I and the 400/110-kV transformer T_I (case #26); between busbar II and the 400/110-kV transformer T_{II} (case #27); between the 110/20-kV transformer T_1 (case #28) and the busbar to which the load L_1 is attached; and between the 110/20-kV transformer T_2 (case #29) and the busbar to which the load L_2 is attached. Whereas, in the two latter cases, the results were not analyzed, since techniques employed at distribution voltage levels were out of the scope of this work.

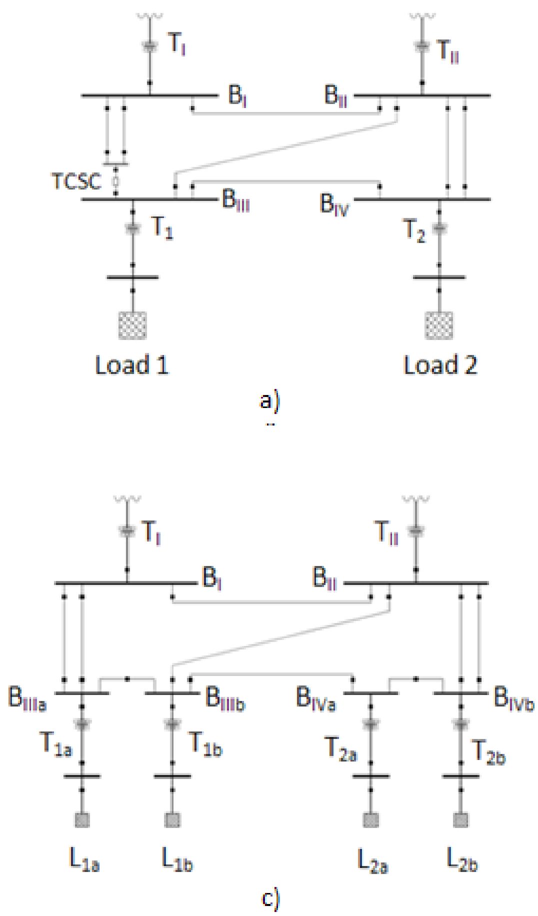


Figure 17: Network cases: a) TCSC; b) series reactor; c) split busbars; and d) upgraded UGC.

V. Installed TCSC (cases #30 - #34):

(**Figure 17a**) The chosen FACTS device, the TCSC, was connected to various parts of line sections in the network (base-case #30). The degree of compensation was 39%, 73%, 61% and 36%, respectively, for cases #31 to #34, in the lower and upper limits of what is generally used (40% and 70%).

Differently from what is commonly accomplished when this device is installed, the TSCS was not installed in association with fixed capacitor banks. This happened in order to investigate the direct effect of this compensation device costs on the tested networks in comparison to the other simulated technologies. Moreover, this alternative, as well as installation of capacitors, is introduced to long lines to compensate their equivalent inductive load and provide voltage support in the substation;

VI. Installed Series Reactor (cases #35 - #42):

(**Figure 17b**) Series reactors were introduced to one or two underground cables in several strategic points of the network (base-case #35), particularly in the cases in which OHLs are connected between the same busbars as UGCs (*i.e.*, receiving power from the same source and distributing to the same substation).

The reactance employed to simulate the reactors were oils of: 1,75Ω (#36); 1,75Ω (#37); 1,75Ω (#38); 2,75Ω (#39); 3Ω (#40); 2,25Ω (#31); and 3Ω (#42).

This technique is often introduced to cables when they are over than 20 km in length. Also, in the cases OHLs and UGCs are built in parallel;

VII. Split Busbar (cases #43 - #49):

(**Figure 17c**) In this subgroup, the busbars III and IV were divided into two new ones (IIIa and IIIb, IVa and IVb). This was performed, so that half of the load was kept in the new busbars (base-case #43). For that, the reserve transformer in each substation was sent to operation, eliminating, thus, the reserve circuit assuring the fulfillment of the (N-1) criterion. However, these new busbars are stil linked and under faulty situation, both transformers and upstream conductors are able to support the temporary (i.e., during the repair and recovery of duplication of load.

VIII. UGC Upgrade (cases #50 - #52):

(**Figure 17d**) In these last cases, it is conducted the upgrade of UGC to larger capacity in order to increase power flow capacity (base-case #50). One UGC (model Al 800) in each case was replaced to another UGC (model Cu 1200), presenting larger ampacity.

The specification of the network cases and load values are presented in **Appendices A.1** and **G.1**.

5.1.2. Simulation, Part II - The Test Network

In this second part of the simulations, the most eligible techniques employed in the previous network analysis were tested in the fictional test network. In this network (identical to

Figure 2), nine cases numbered from T1 (base case) to T9 cover the effect of FCL, series reactor, busbar split and cable upgrade in two different locations.

The parameters selected were smaller than the ones in the network cases and the load considered was significantly smaller. The specification of the network cases and load values are presented in **Appendices A.2** and **G.2**.

Moreover, the types of overhead lines used in all simulated cases were single circuit Al/Fe 205/33 and double circuit Al/Fe 205/33, according to network needs. In the case of underground cables, Al 800 cables were employed with the exception of two the UGC upgrade cases, in which Cu 1200 cables were selected to upgrade the network. Conductors are thoroughly described in **Appendices B** and **F**.

5.2. Considerations

5.2.1. Power Flow in the Network

The first stage of the simulation is the establishment of the electrical values in the network. Initially, having all components and conductors defined in the case network, the electrical parameters must be calculated in order to offer input to the reliability study and fault level analysis. These parameters are conductor current and power through each conductor (active, reactive and apparent) at the base year. With these, power losses and voltage drops are accounted in the calculation.

Secondly, all electrical parameters are shifted to the end of the load-growth period (40 years), at the given interest and load-growth rates, to specify the overloads across the lifespan of conductors and equipment. At this point, it is possible to analyze the reliability of a network, for current values must be within the tolerable range supported by cables and lines after the 40 years. Further, the (N-1) criterion could not be fulfilled in all the network cases to provide a higher degree of reliability.

In UGC, where insulation is more sensitive to thermal stress, originated by overcurrents, higher caution about steady-state currents and power flows is considered and likewise the design of the enhanced network cases accredits the best, *i.e.*, most egalitarian, distribution of currents throughout the network. As a consequence, this represents the idea of optimal parallel operation of underground cables and overhead lines.

Altogether, voltage drops in conductor sections must be under 2% of nominal voltage and current value under normal system operation. Besides, there must be less than the rated current for the chosen conductor.

5.2.2. Fault Levels in the Substations

As the second stage of this study, given all demanding parameters and considering the topological nature of each network case, fault levels are computed at the four 110-kV busbars. The three-phase fault on each of them was simulated and short-circuit and peak short-circuit values were calculated for the purpose of obtaining the maximum current level achieved during contingency.

The short-circuit current is computed from:

$$I_{sc} = \frac{I_b}{Z_{th}} \qquad \text{(eq. 32)}$$

And the peak short-circuit current can be acquired from:

$$I_p = \kappa\sqrt{2}I_{sc} \qquad \text{(eq. 33)}$$

In which the factor κ is:

$$\kappa = 1{,}02 + 0{,}98e^{-R_{th}/X_{th}} \qquad \text{(eq. 34)}$$

I_{sc}: short-circuit current [kA];

I_b: system base current [kA];

I_p: peak short-circuit current [kA];

Z_{th}: Thévenin impedance [pu];

R_{th}: Thévenin resistance [pu];

X_{th}: Thévenin reactance [pu].

In complement to the short-circuit levels, the peak short-circuit value is calculated, which is the highest magnitude of current occurring at the first half cycle, and has direct effect on equipment integrity during fault. The behavior of both parameters is calculated in all network cases, with particular attention in the second group of simulated cases.

Moreover, the usage of more complex mathematical tools to compute these values is unnecessary. In the case of radial networks, calculations are straightforward and can be accomplished by direct use of the above mentioned equations. At a more laborious level, yet reasonably manageable, other network topologies in a four-busbar network can be computed without the assistance of complex algorithms.

5.2.3. Reliability Analysis & Cost

The third stage of this simulation is the reliability study and estimation of total network costs. In this phase, an investigation of load related costs due to interruptions is carried out in each network case and an estimated customer interruption cost over the end of the review period is returned in the cases presenting outage. In addition, computation of the four different components of the cost functions are calculated and attributed to all networks.

The reliability analysis and cost estimation were undertaken utilizing parameters from **Appendices C, D, E** and **F** as well as the theoretical and analytical methodologies presented in **Chapter 4**. For the purpose of identifying interruption costs, only one outage was accounted *per* time, *i.e.*, no simultaneous interruptions happened. This was considered, for the test network is relatively small and the sum of all conductor lengths is below 100 km in all cases. Even though the chances are quite diminished, there is the possibility of simultaneous outage events in real networks.

The cost estimation was performed employing as many real values and data as possible, as the ones attributed in **Appendix C**. However, the insertion of estimated costs and attributed values for services and device installation were required to fill in the blanks and to converge to a real network value.

5.3. Results

The results from simulations undertaken in the reliability and fault level studies are: presented as total cost; cost share in percentage; cost per kilometer of conductor; attributed cost to equipment/technique introduced to network; and short-circuit and peak levels.

The values obtained the two simulations (network cases and test network) are placed separately.

5.3.1. Total Cost

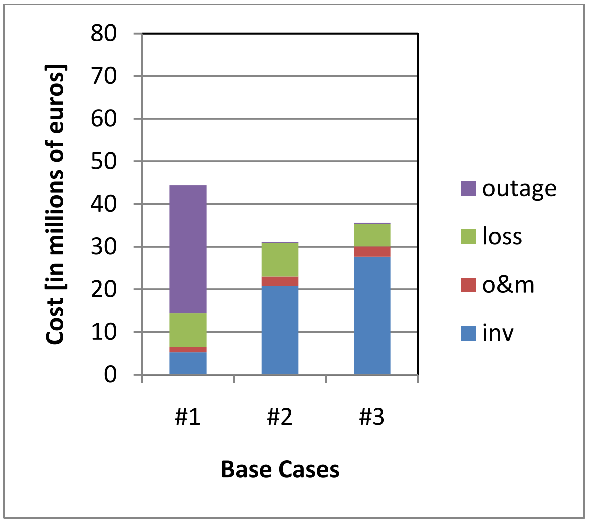


Chart 1: Total cost (base networks).

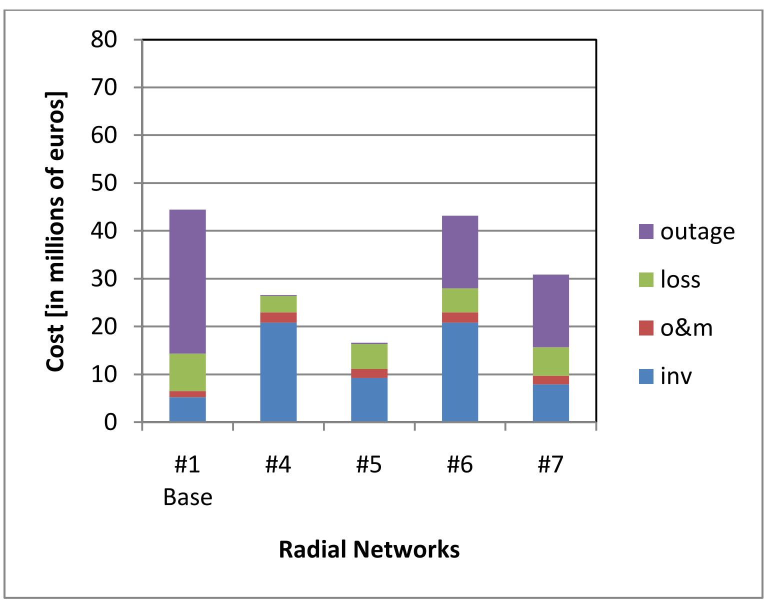


Chart 2: Total cost (radial networks).

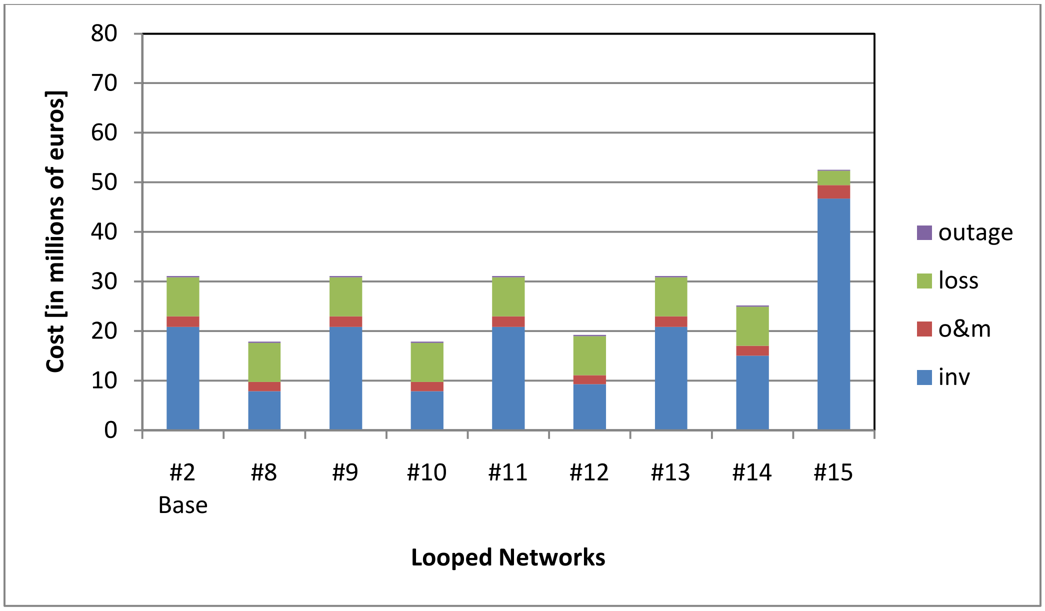


Chart 3: Total cost (looped networks).

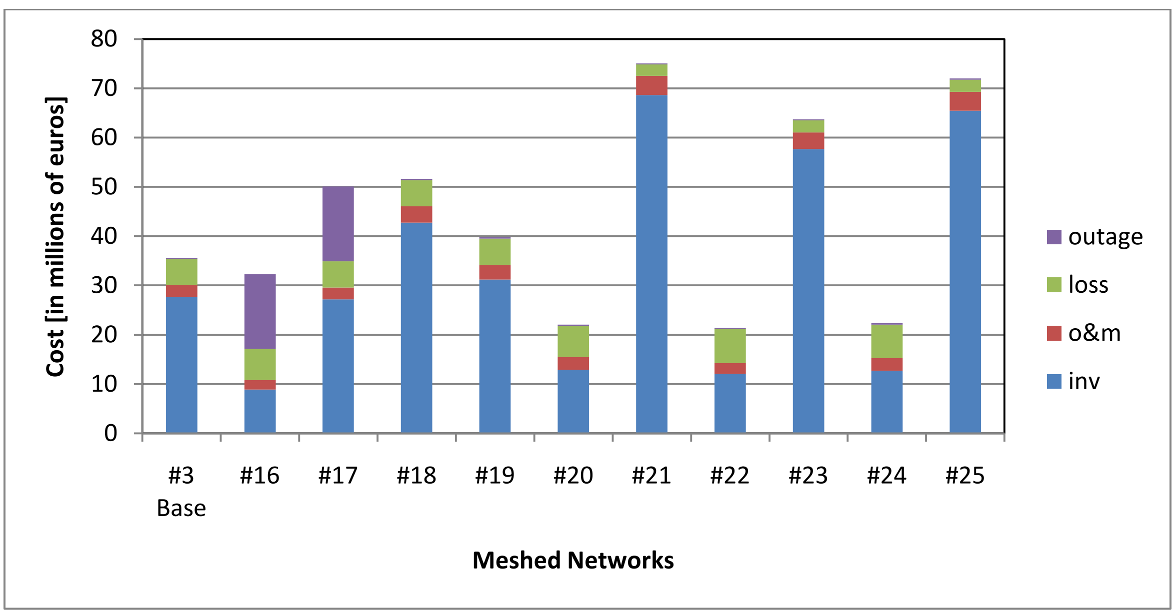


Chart 4: Total cost (meshed networks).

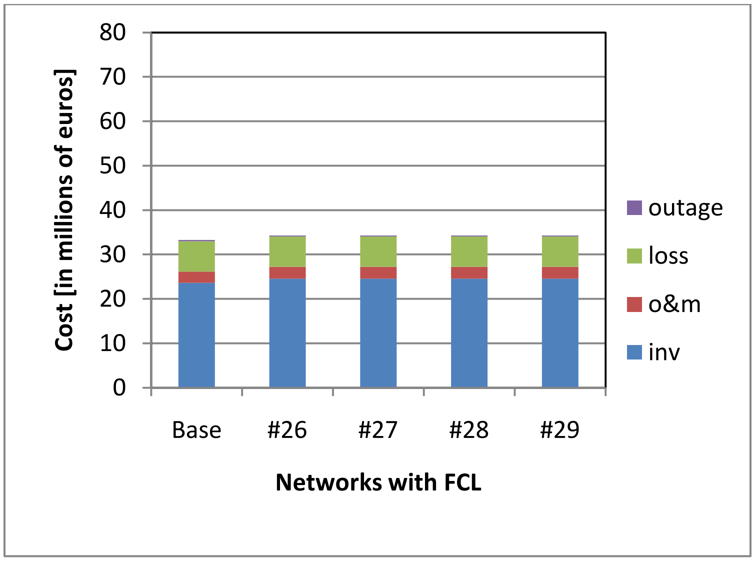


Chart 5: Total cost (FCL installed)

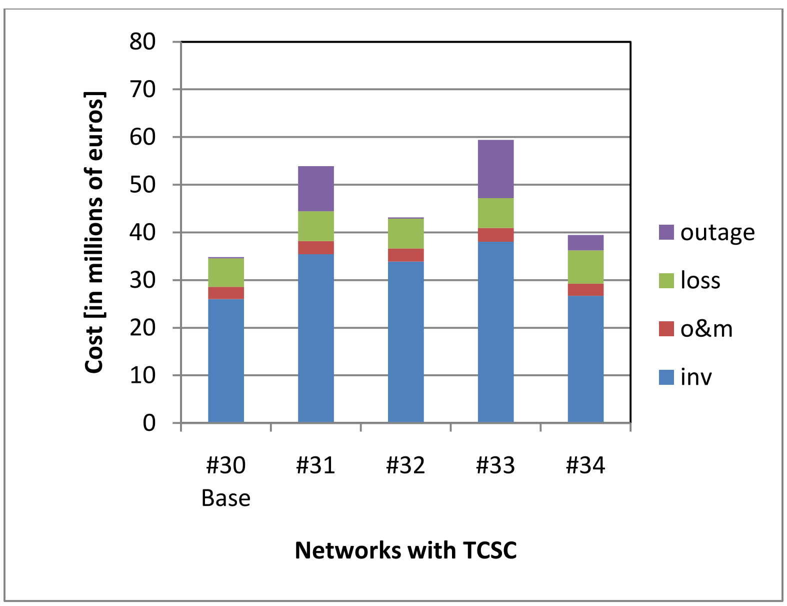


Chart 6: Total cost (TCSC installed).

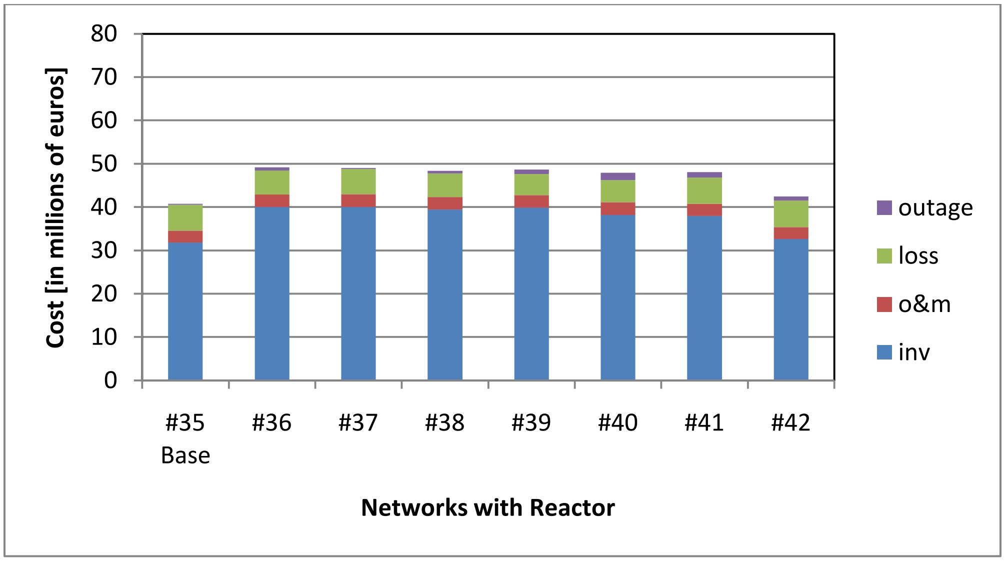


Chart 7: Total cost (series reactor installed).

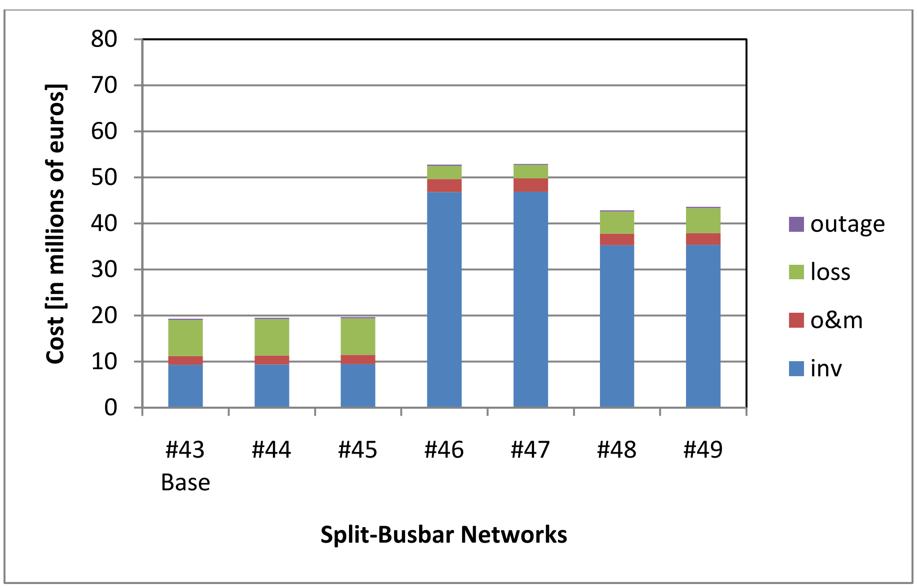


Chart 8: Total cost (split busbars).

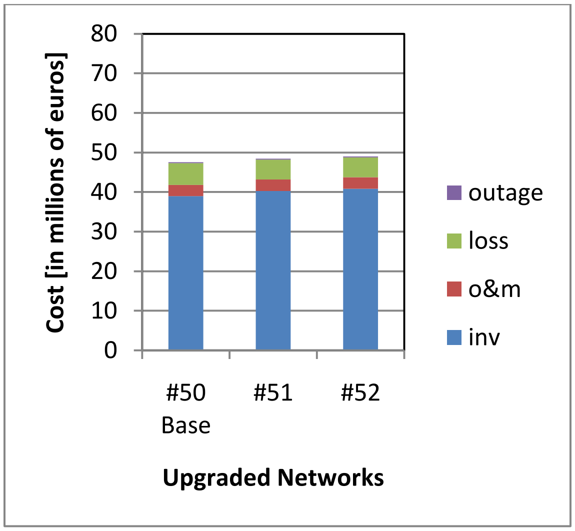


Chart 9: Total cost (upgraded UGC).

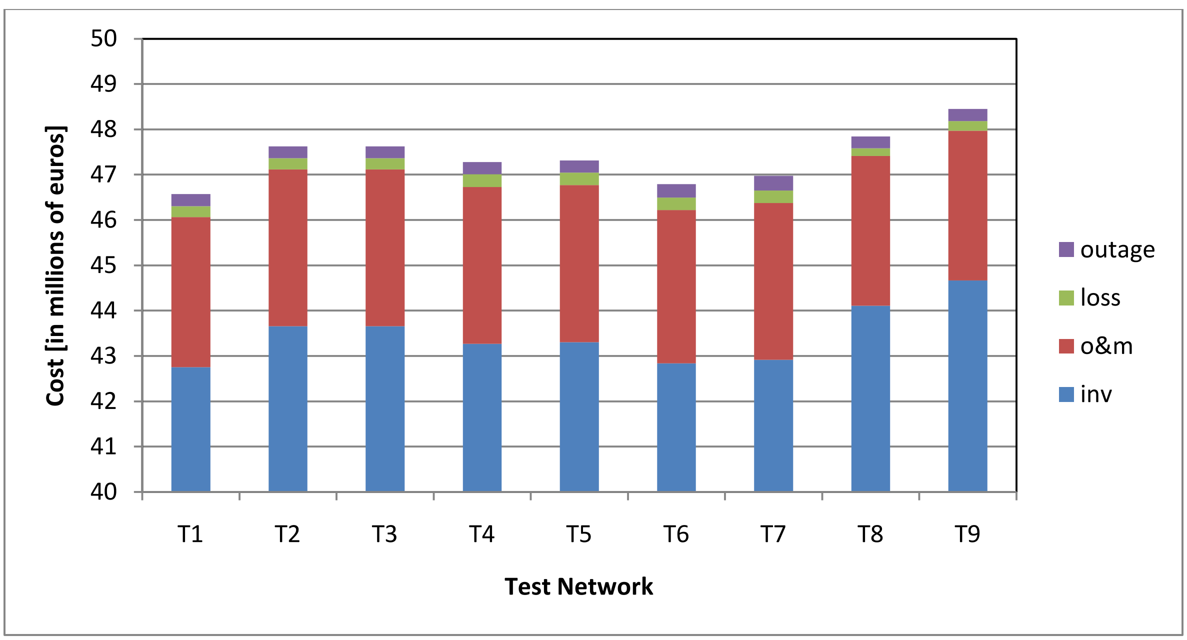


Chart 10: Total cost (Test Network).

Table 5: Cost comparison between employed techniques.

Case	Equipment installed	Comp./Equip. Cost [€]	Cost related to total cost
#26	FCL (between TI and busbar I) A	***1 056 451***	***3,08 %***
#27	FCL (between TII and busbar II) B	***1 056 451***	***3,08 %***
#28	FCL (T1 MV side) C	***1 056 451***	***3,08 %***
#29	FCL (T2 MV side) D	***1 056 451***	***3,08 %***
#31	TCSC A	***9 822 663***	***18,22 %***
#32	TCSC B	***8 192 422***	***18,99 %***
#33	TCSC C	***12 648 440***	***21,30 %***
#34	TCSC D	***3 134 369***	***7,94 %***
#36	Reactor A	***626 698***	***1,28 %***
#37	Reactor B	***1 272 170***	***2,59 %***
#38	Reactor C	***487 150***	***1,01 %***
#39	Reactor D	***1 120 955***	***2,30 %***
#40	Reactor E	***2 491 067***	***5,19 %***
#41	Reactor F	***1 432 221***	***2,98 %***
#42	Reactor G	***1 006 923***	***2,37 %***
#44	Split A (busbar III)	**156 226**	**0,80 %**
#45	Split B (busbars III & IV)	**312 451**	**1,59 %**
#46	Split C (busbar III)	**156 226**	**0,30 %**
#47	Split D (busbars III & IV)	**312 451**	**0,59 %**
#48	Split E (busbar III)	**156 226**	**0,36 %**
#49	Split F (busbars III & IV)	**312 451**	**0,72 %**
#51	Upgrade A	***9 910 671***	***20,48 %***
#52	Upgrade B	***13 671 145***	***27,92 %***

Table 6: Cost comparison between employed techniques in the test network.

Case	Equipment installed	Comp./Equip. Cost [€]	Cost related to total cost
T2	FCL I (between TI and busbar I)	***1 056 451***	***1,90 %***
T3	FCL II (between TII and busbar II)	***1 056 451***	***1,90 %***
T4	Reactor I	***673 341***	***1,42 %***
T5	Reactor II	***712 338***	***1,51 %***
T6	Split (Bar III)	***146 226***	***0,31 %***
T7	Split (Bar III & IV)	***292 451***	***0,62 %***
T8	Upgrade I	***9 647 696***	***20,17 %***
T9	Upgrade II	***13 476 659***	***27,82 %***

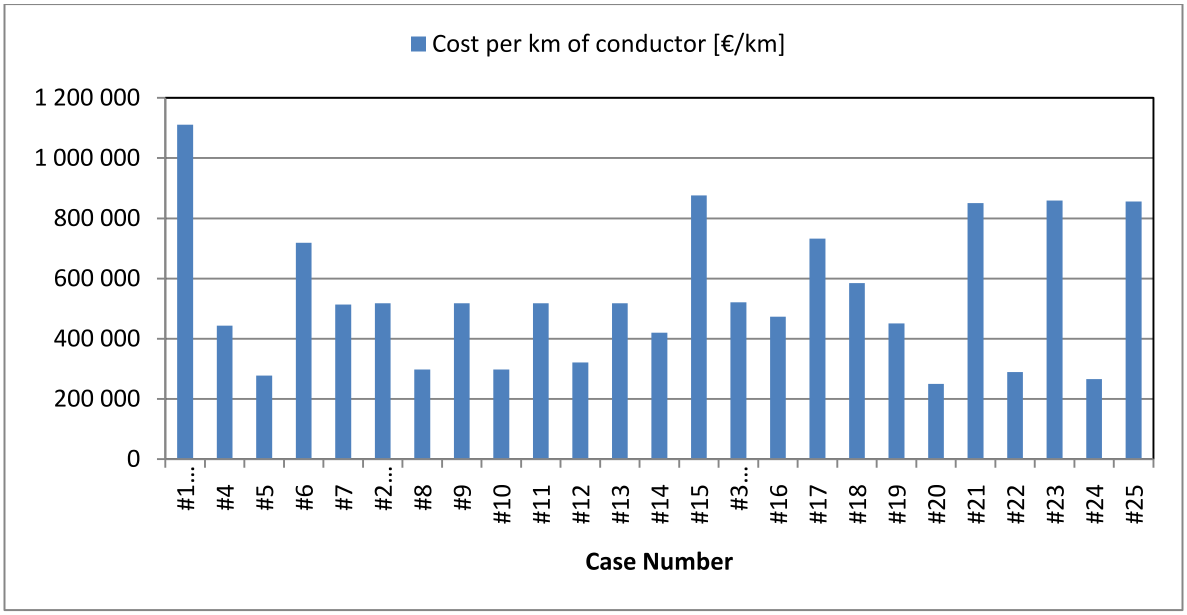


Chart 11: Total cost per km of conductor.

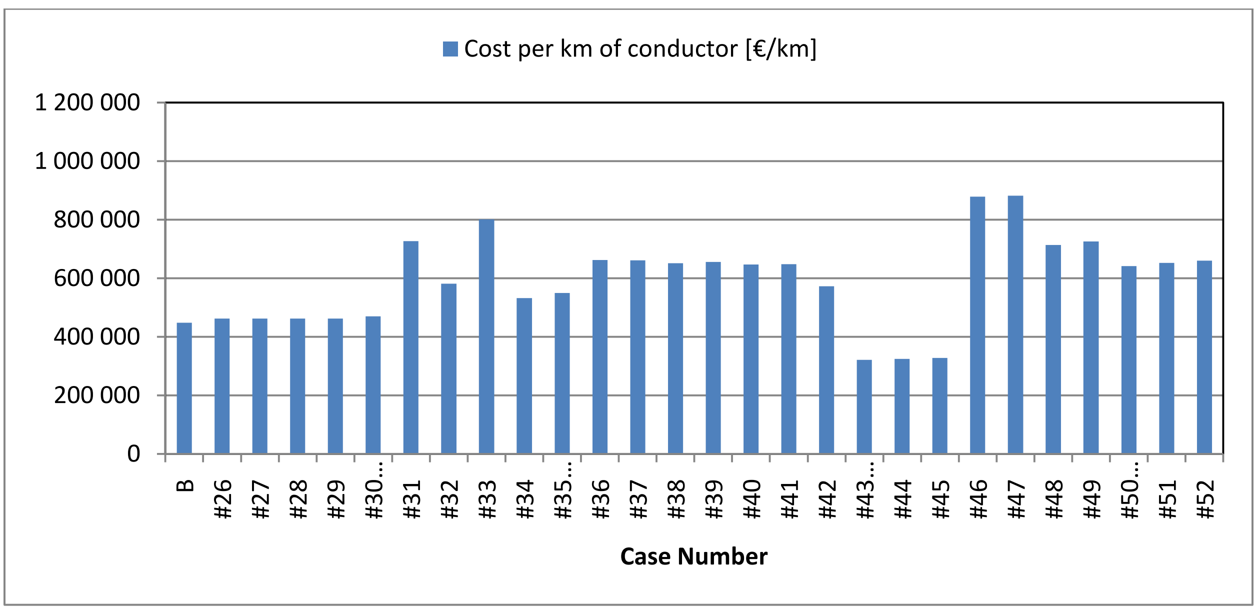


Chart 12: Total cost per km of conductor.

5.3.2. Cost Composition in Percentage

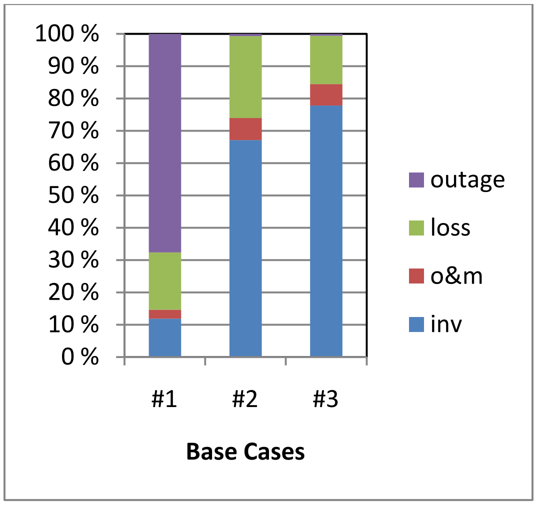


Chart 13: Cost composition (base networks).

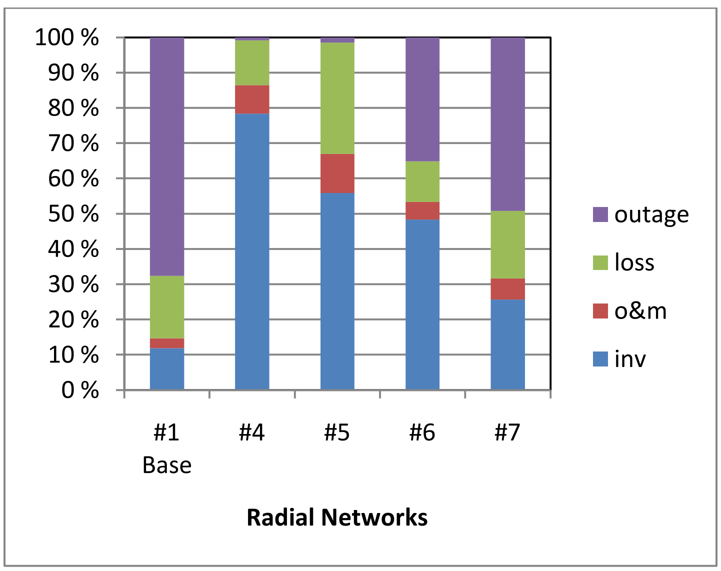


Chart 14: Cost composition (radial networks).

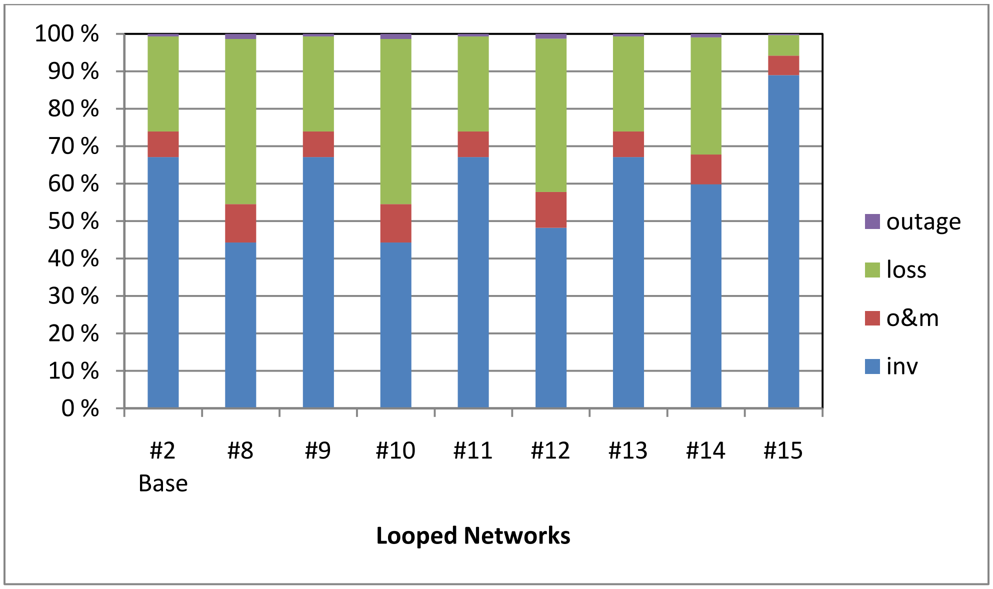


Chart 15: Cost composition (looped networks).

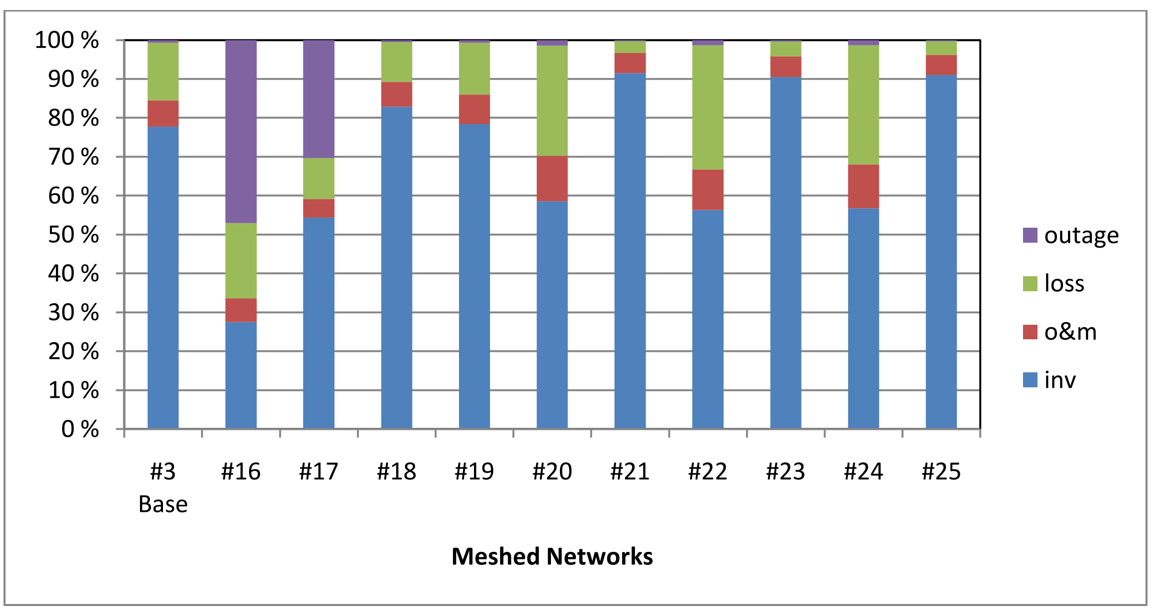


Chart 16: Cost composition (meshed networks).

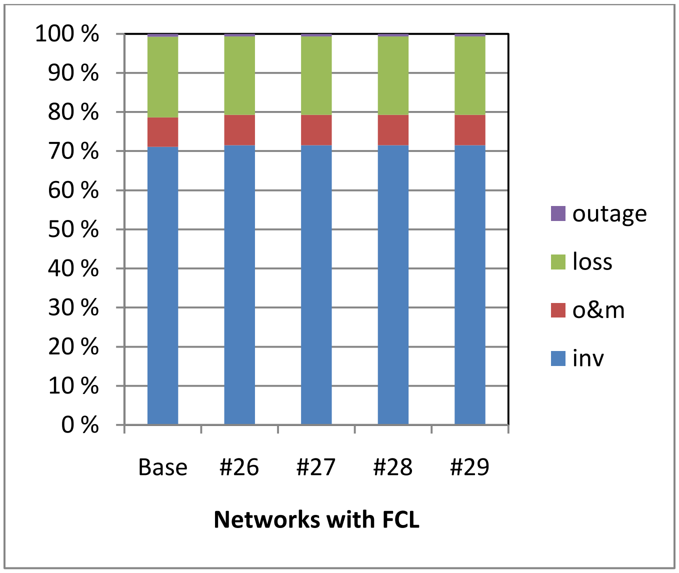


Chart 17: Cost composition (FCL installed).

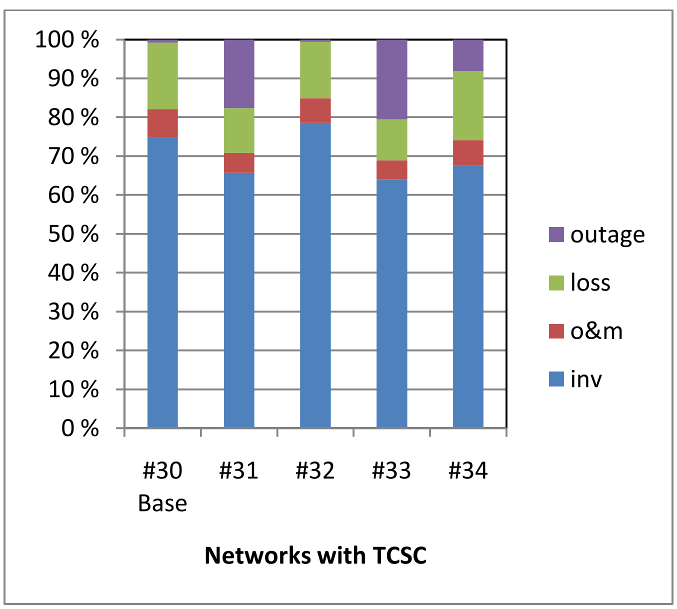


Chart 18: Cost composition (TCSC installed).

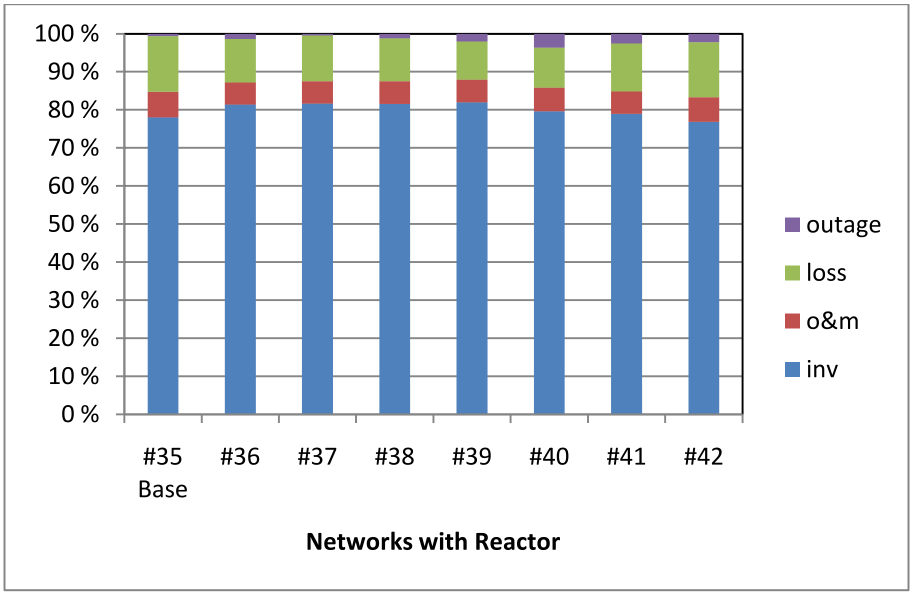


Chart 19: Cost composition (series reactor installed).

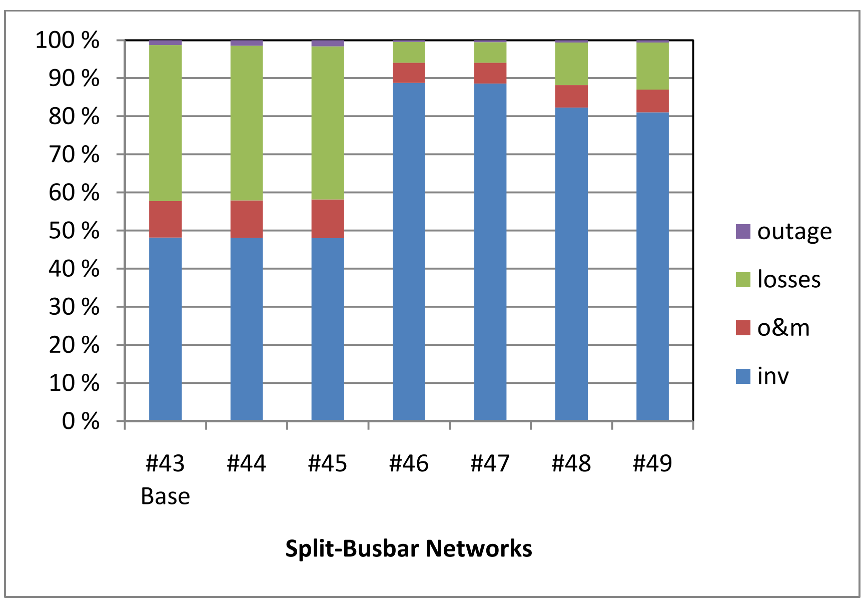


Chart 20: Cost composition (split busbars).

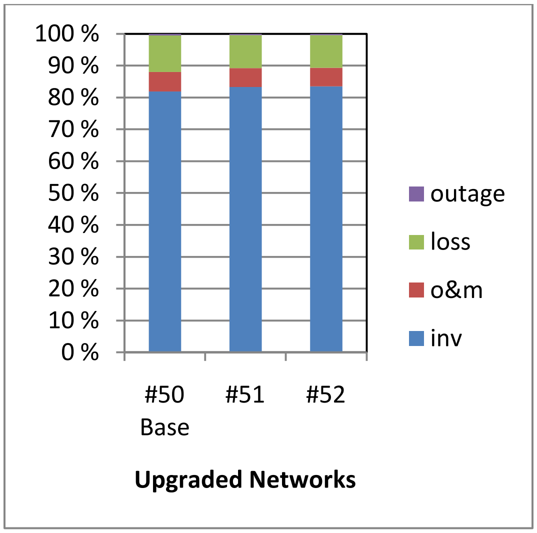


Chart 21: Cost composition (upgraded UGC).

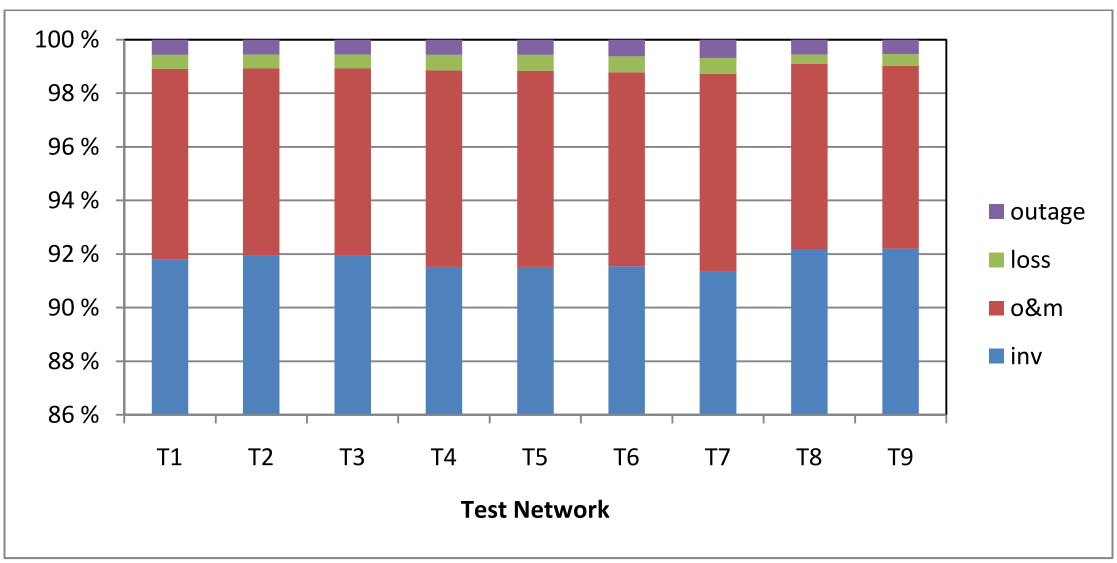


Chart 22: Cost Composition (Test Network).

5.3.3. Short-Circuit and Peak Levels at the Busbars

I. Network Cases (Simulation, Part I):

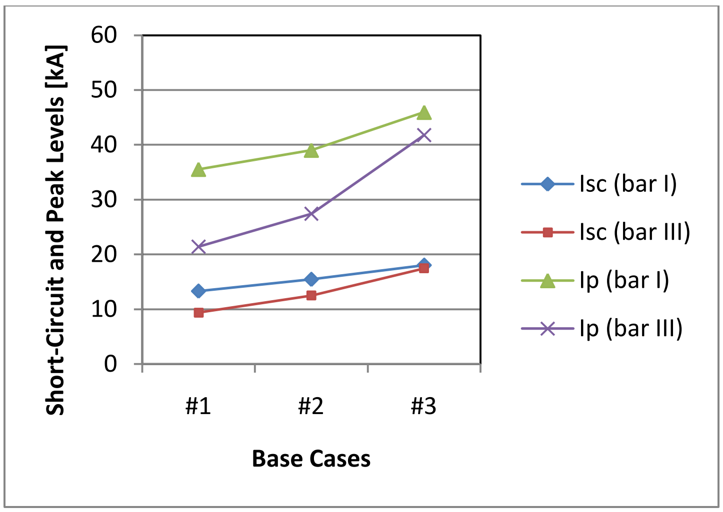


Chart 23: Fault levels at busbars I & III (base networks).

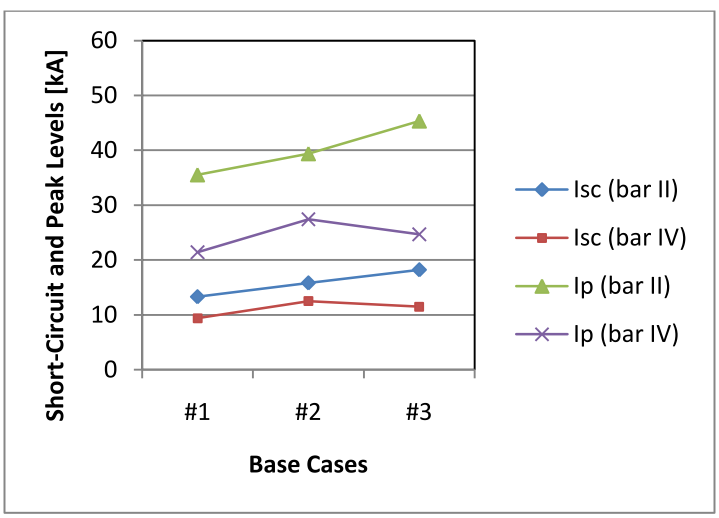


Chart 24: Fault levels at busbars II & IV (base networks).

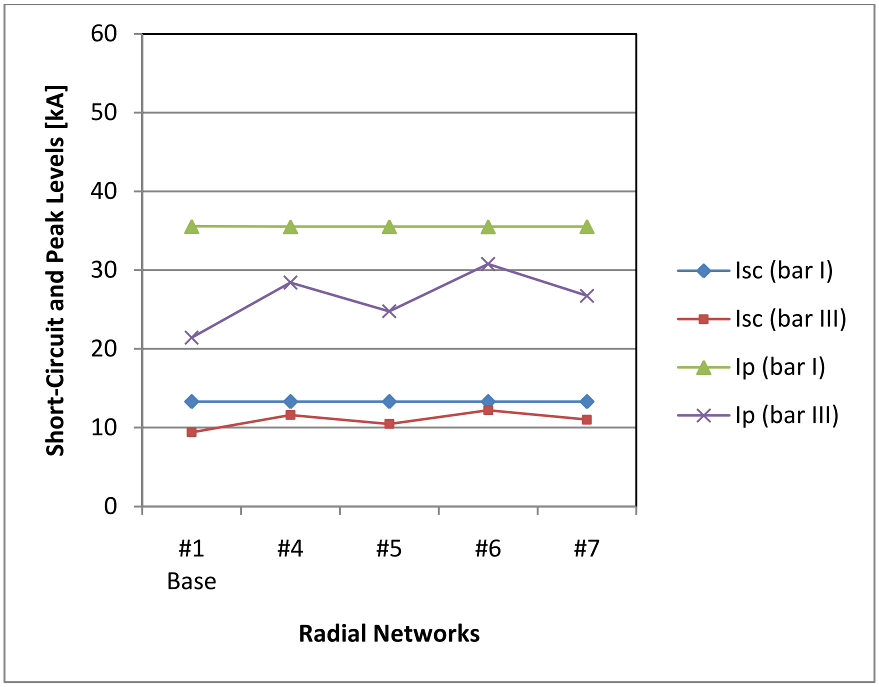


Chart 25: Fault levels at busbars I & III (radial networks).

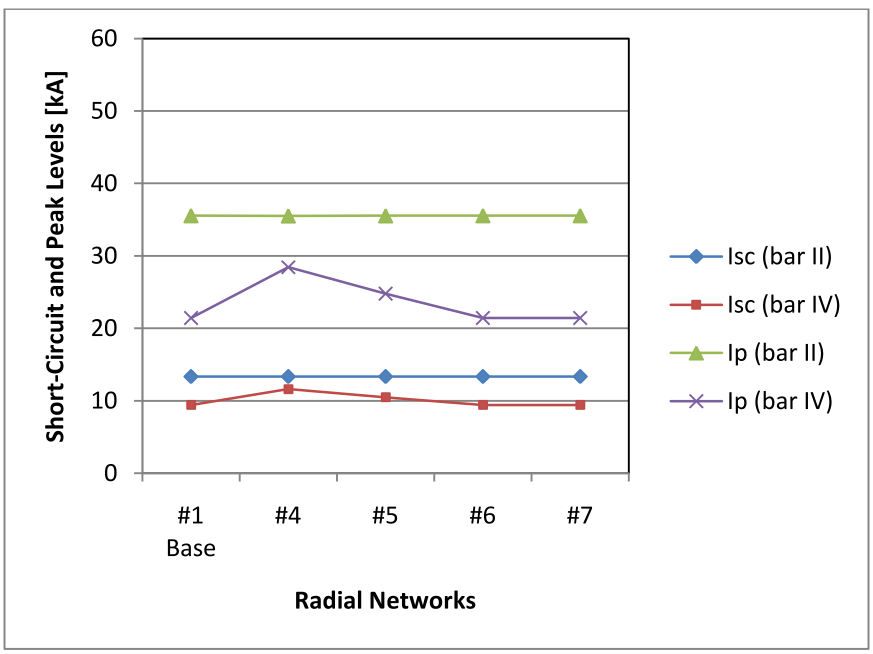


Chart 26: Fault levels at busbars II & IV (radial networks).

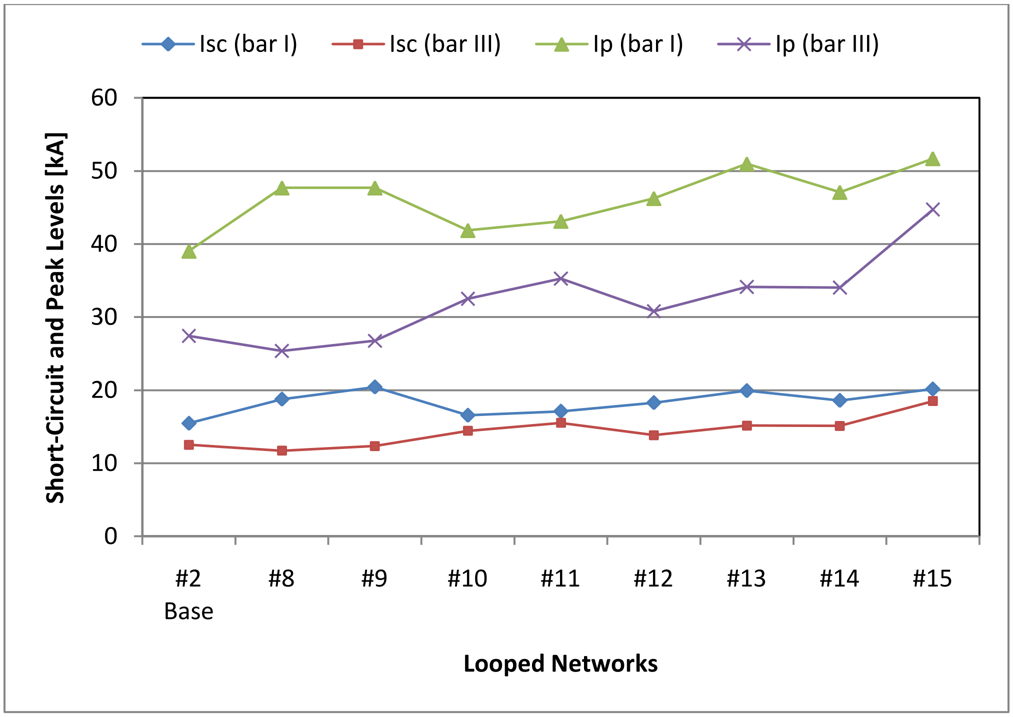


Chart 27: Fault levels at busbars I & III (looped networks).

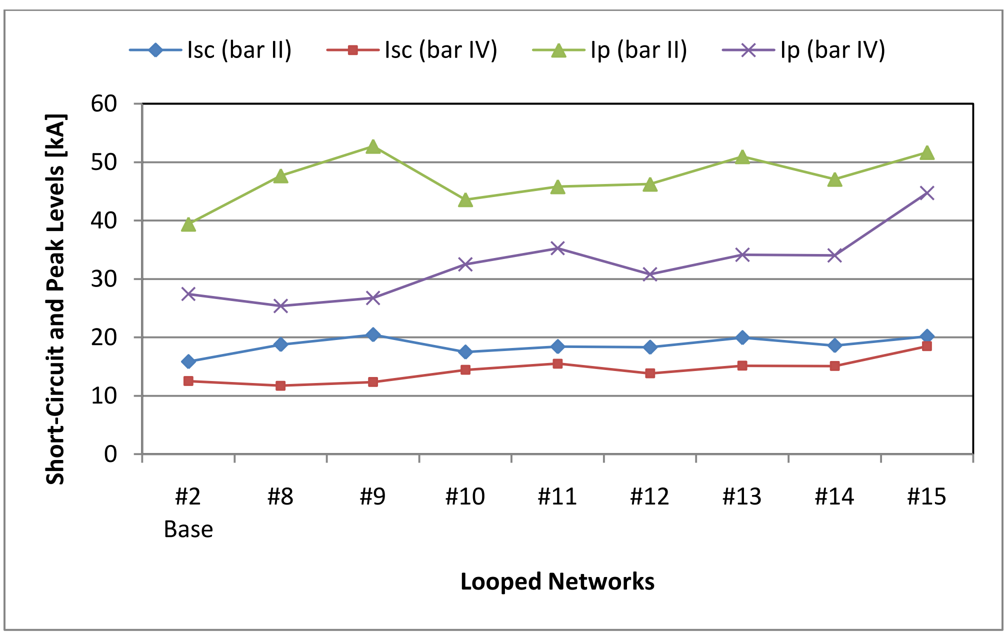


Chart 28: Fault levels at busbars II & IV (looped networks).

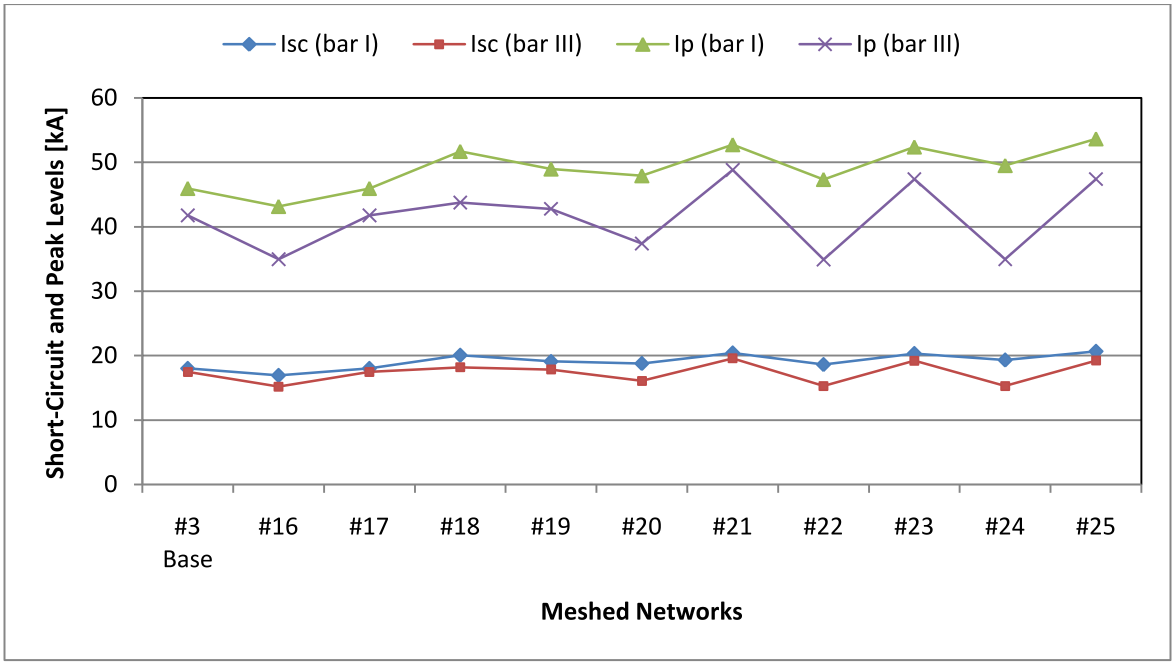


Chart 29: Fault levels at busbars I & III (meshed networks).

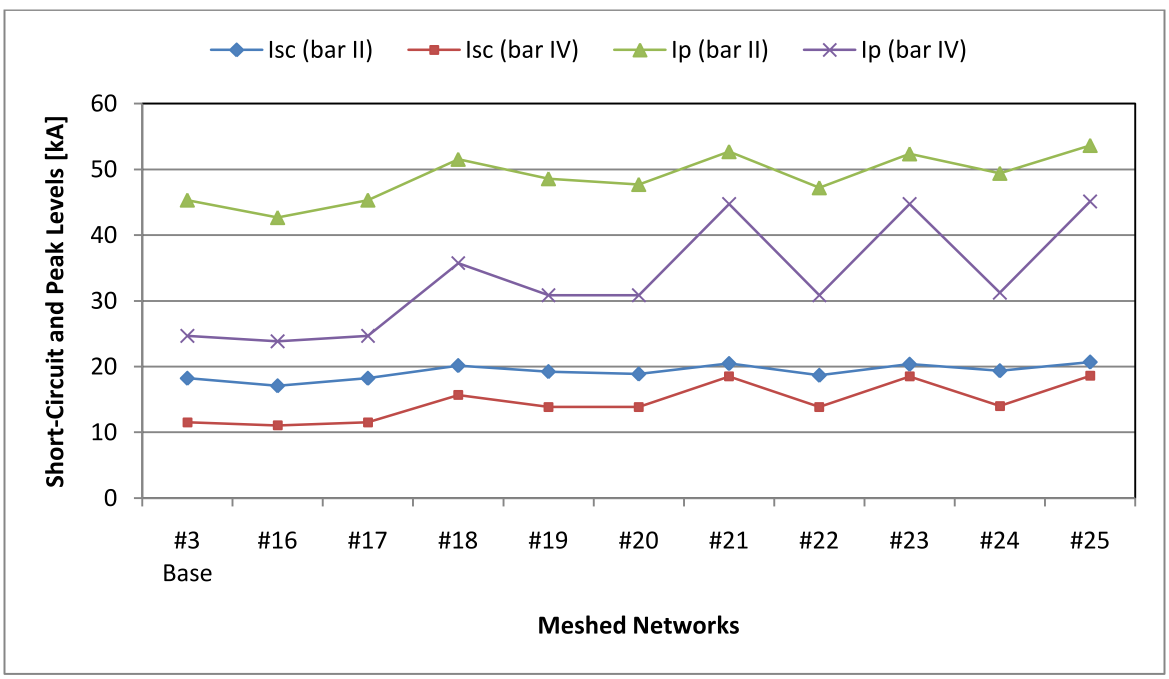


Chart 30: Fault levels at busbars II & IV (meshed networks).

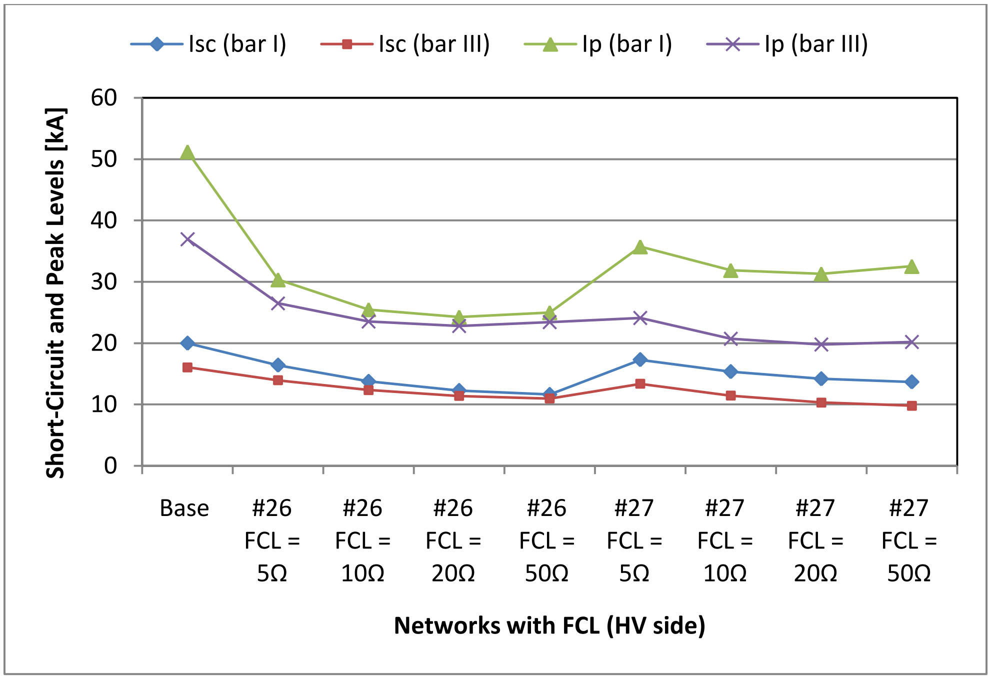


Chart 31: Fault levels at busbars I & III (FCL installed at HV side).

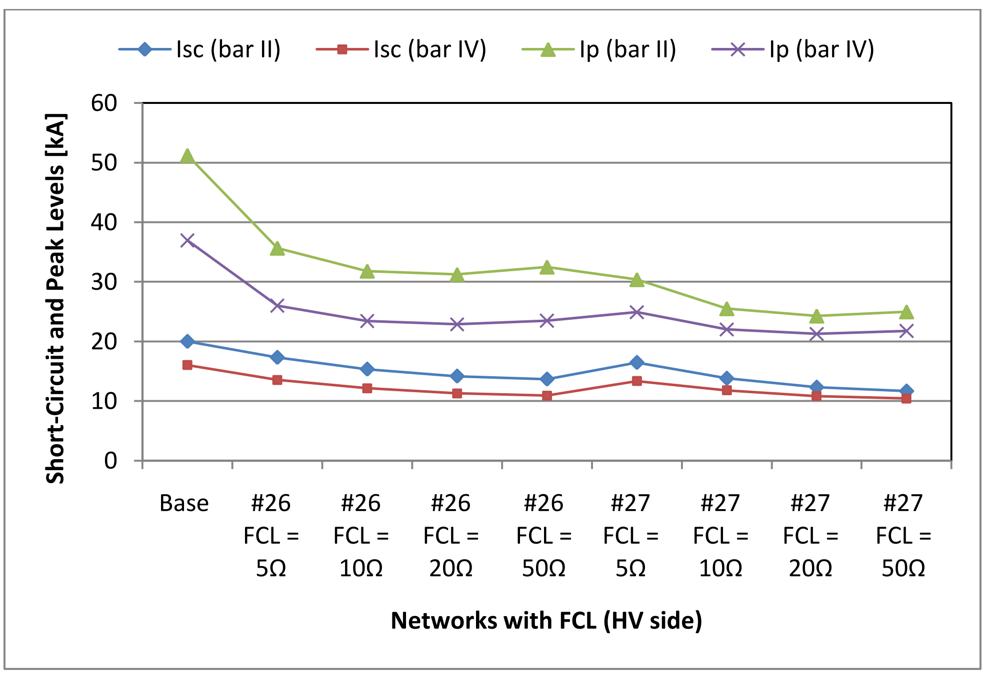


Chart 32: Fault levels at busbars II & IV (FCL installed at HV side).

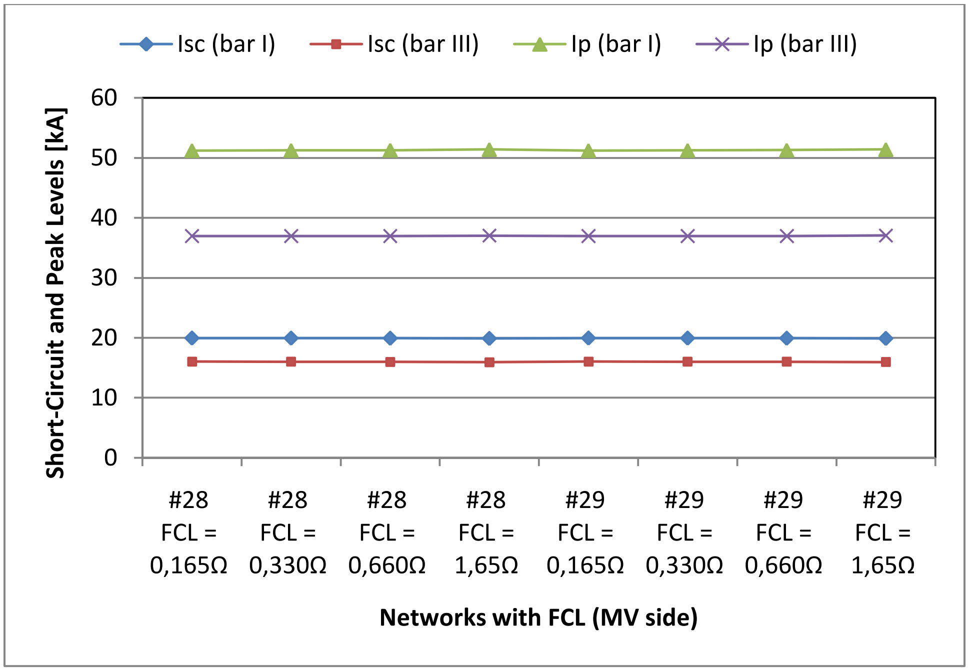


Chart 33: Fault levels at busbars I & III (FCL installed at MV side).

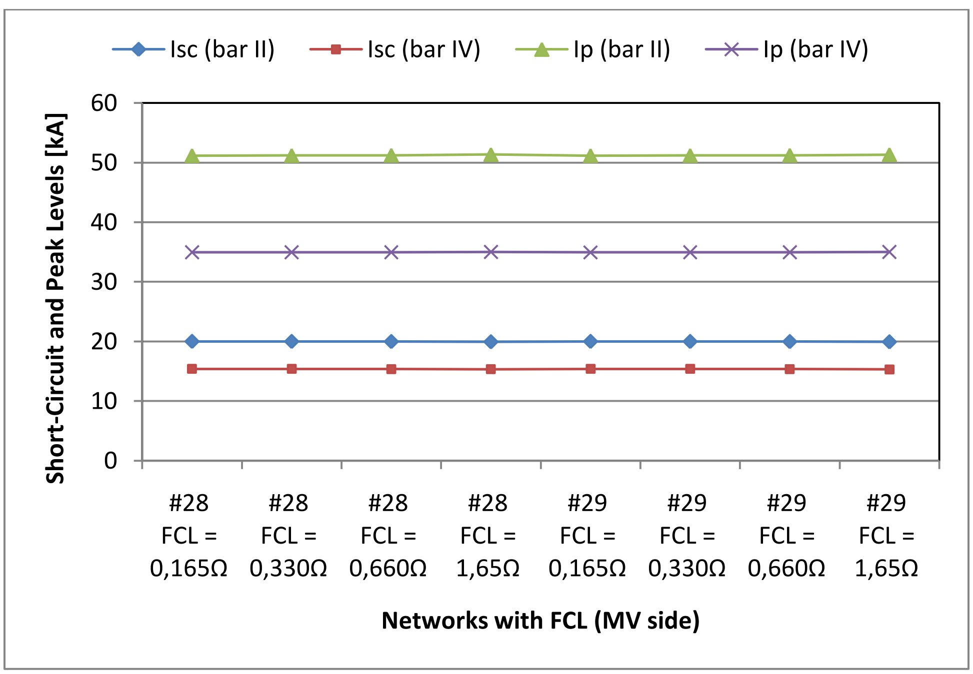


Chart 34: Fault levels at busbars II & IV (FCL installed at MV side).

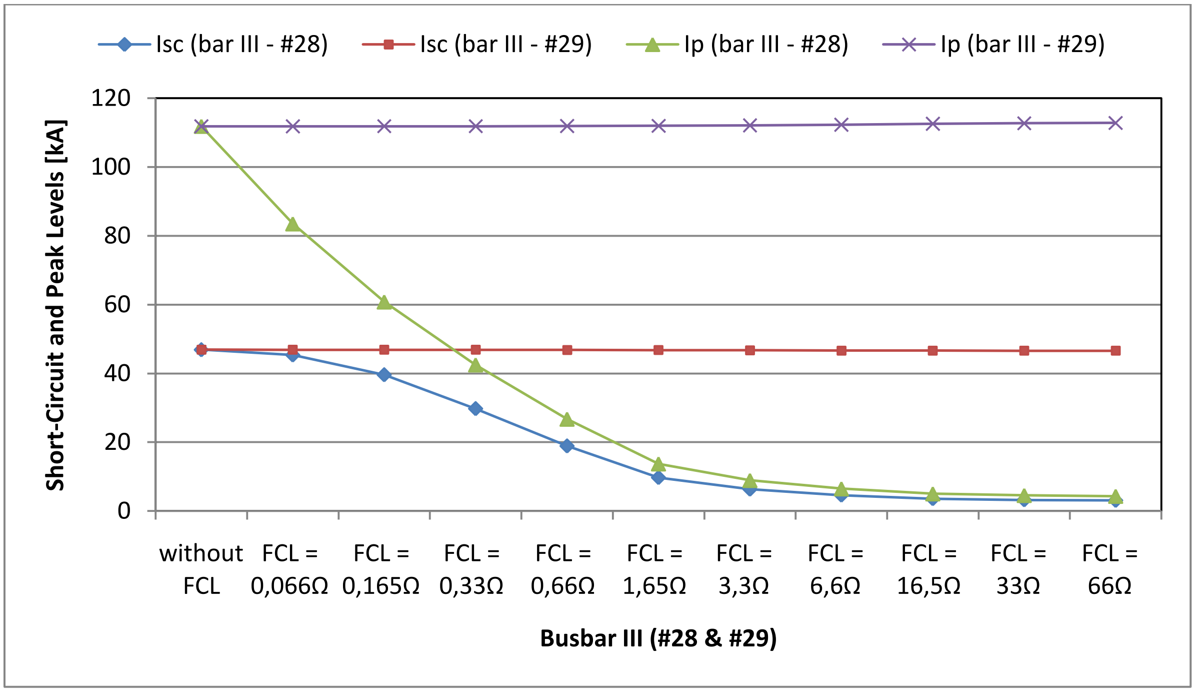


Chart 35: Fault levels at busbar III for FCL installed at MV side.

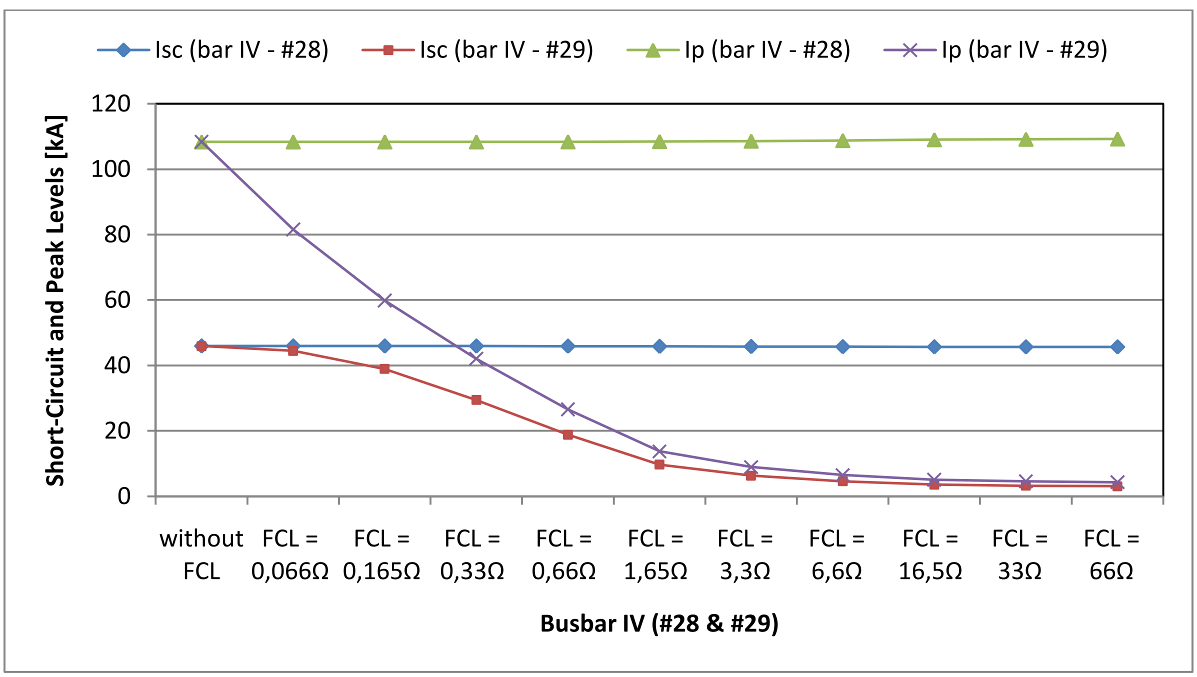


Chart 36: Fault levels at busbar IV for FCL installed at MV side.

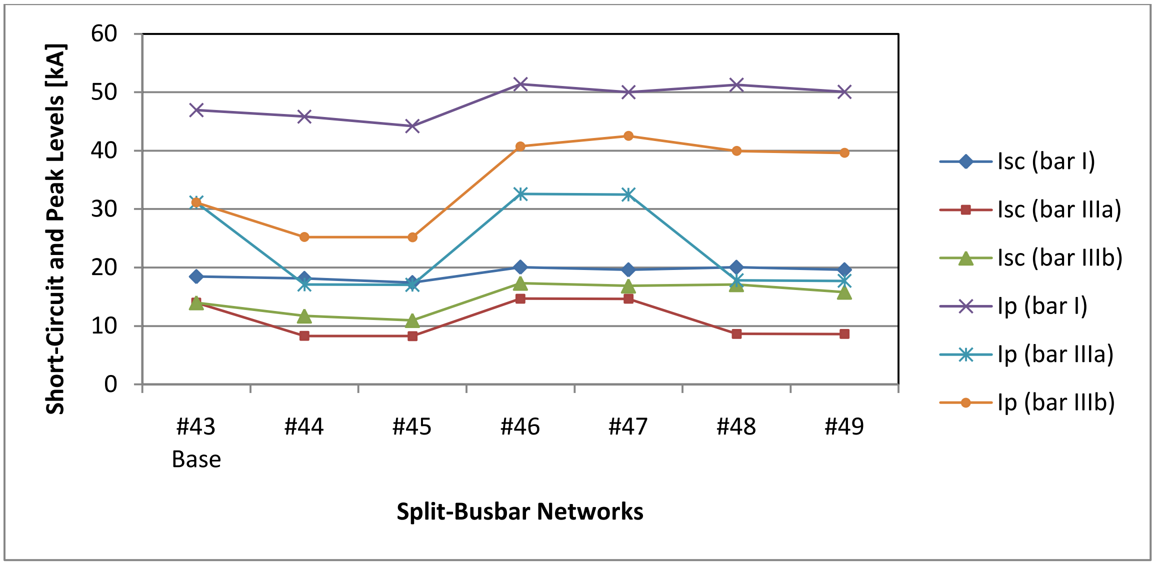


Chart 37: Fault levels at busbars I, IIIa & IIIb (split busbars).

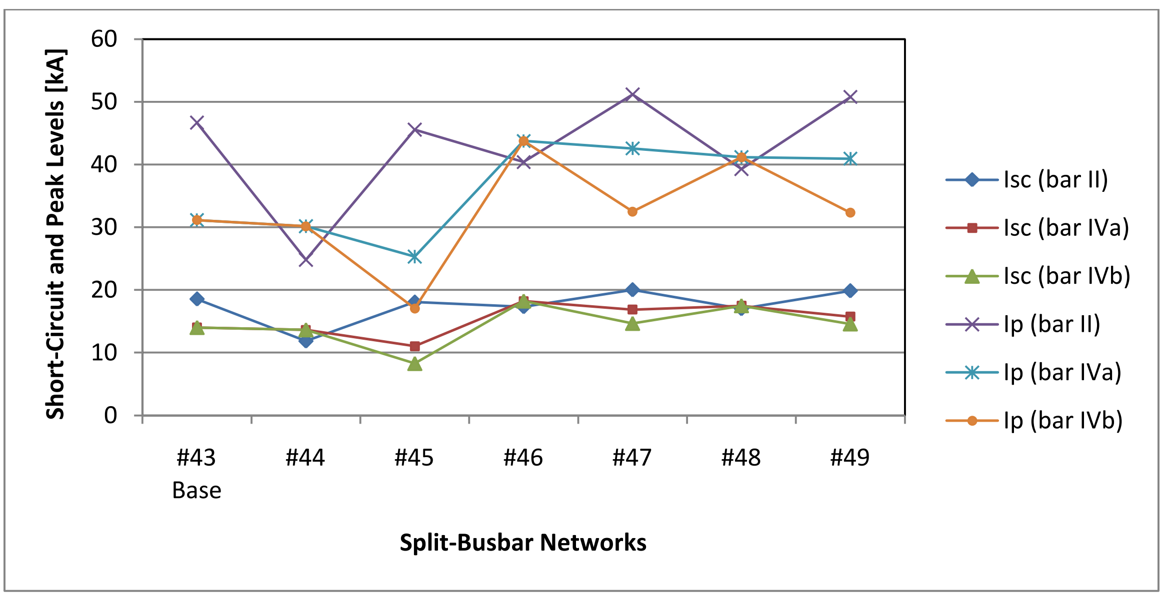


Chart 38: Fault levels at busbars II, IVa & IVb (split busbars).

In **Charts 37** and **38**, note that for the base case (busbars were not divided) and for the cases #44, #46 and #48, the values at busbars IVa and IVb are the same (in these, busbar IV was not divided).

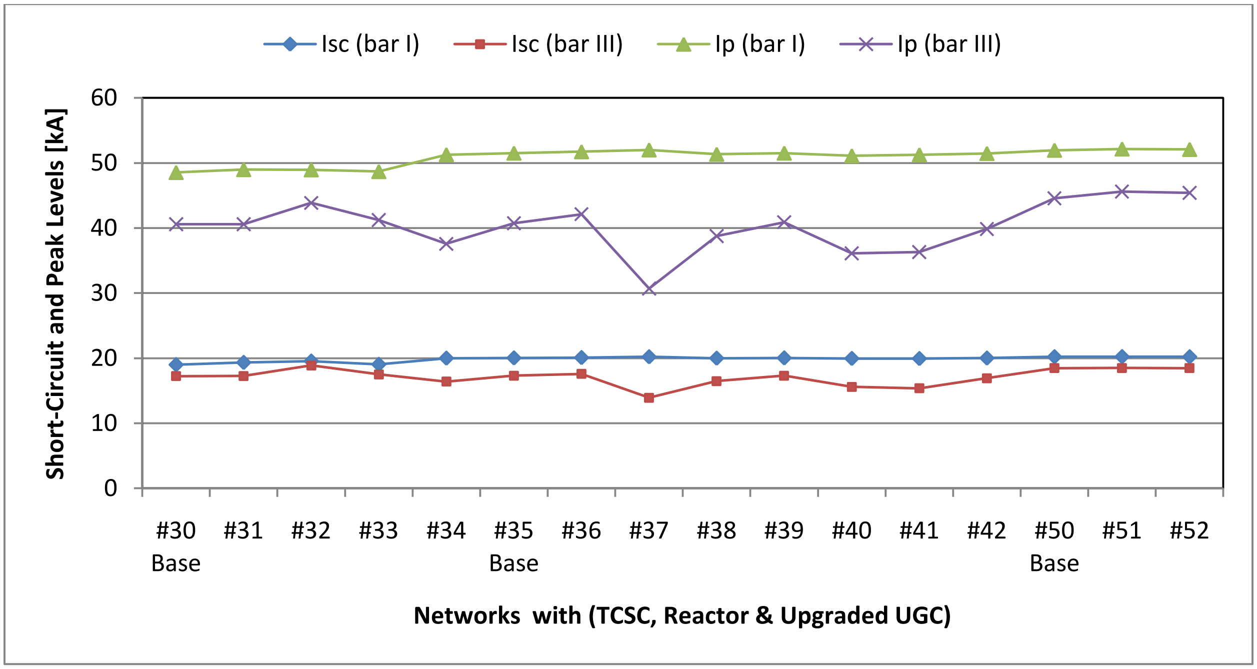


Chart 39: Fault levels at busbars I & III (TCSC, series reactors and upgraded UGC).

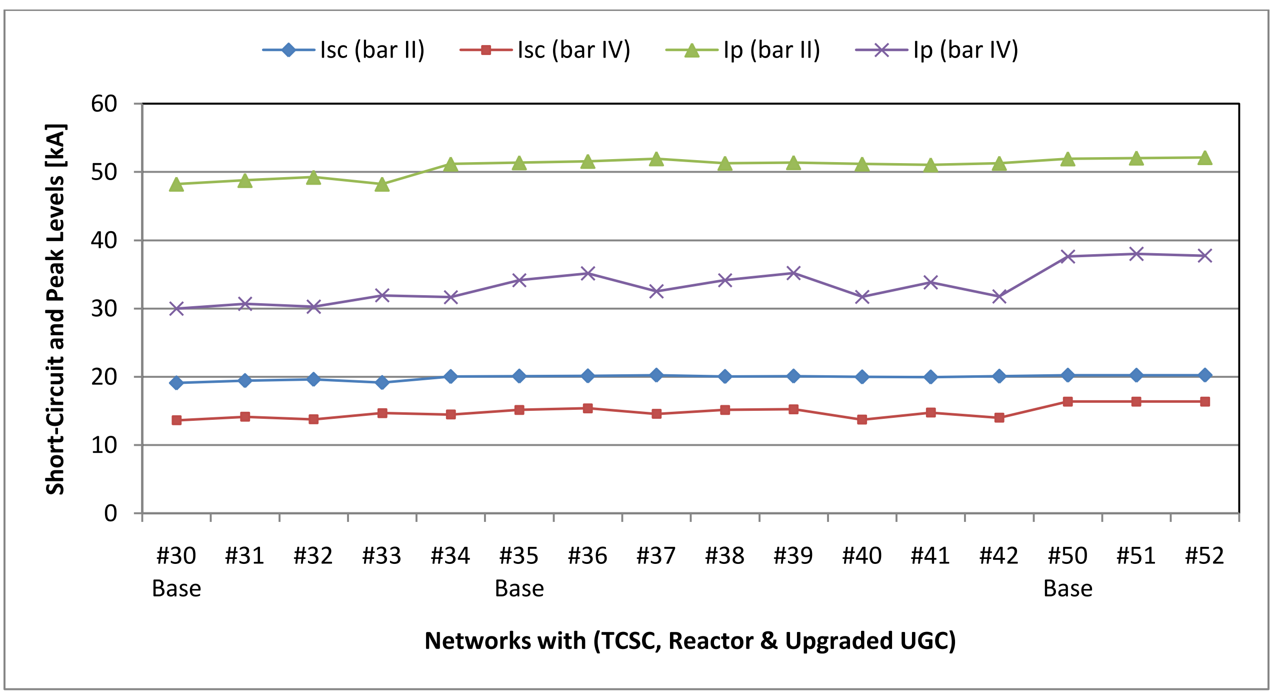


Chart 40: Fault levels at busbars II & IV (TCSC, series reactors and upgraded UGC).

II. Test Network (Simulation, Part II):

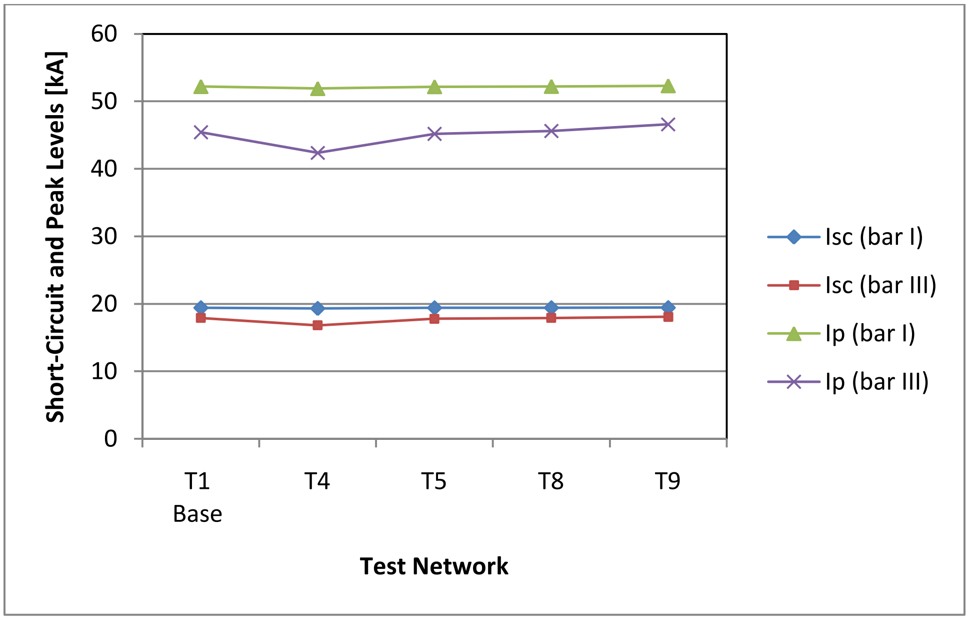


Chart 41: Fault levels at busbars I & III (reactor, T4 and T5; upgrade, T8 and T9).

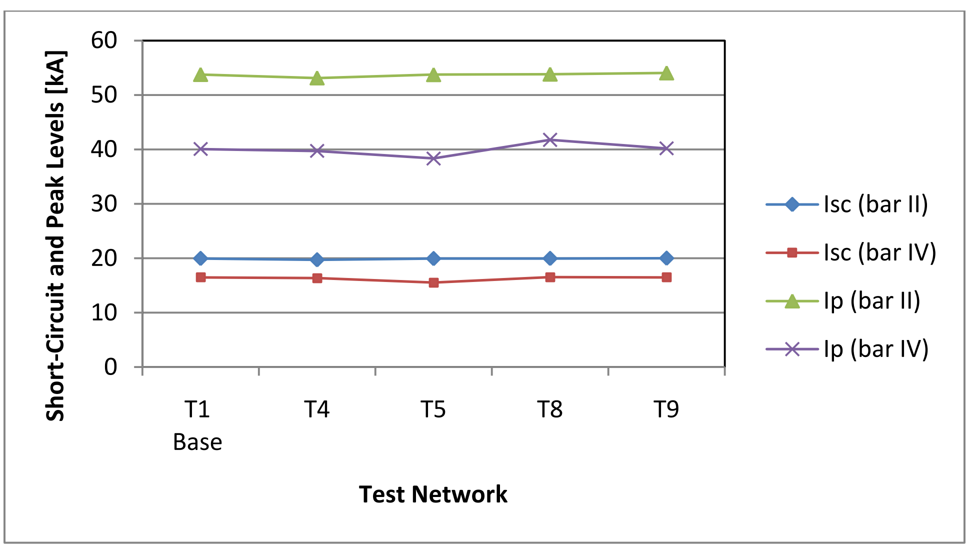


Chart 42: Fault levels at busbars II & IV (reactor, T4 and T5; upgrade, T8 and T9).

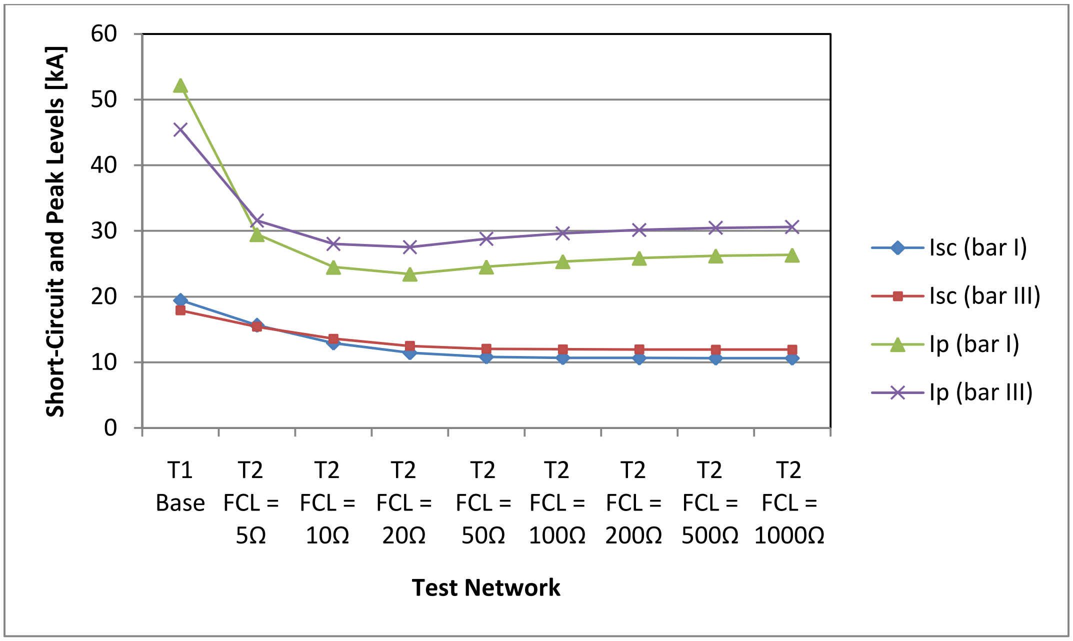


Chart 43: Fault levels at busbars I & III (FCL, T2).

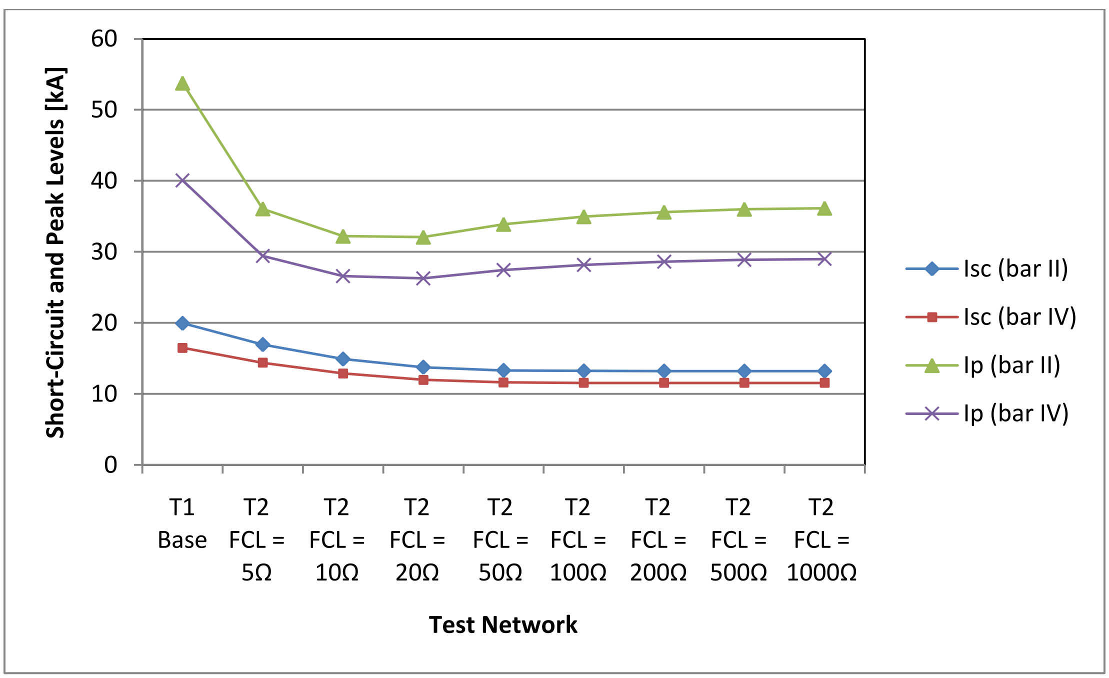


Chart 44: Fault levels at busbars II & IV (FCL, T2).

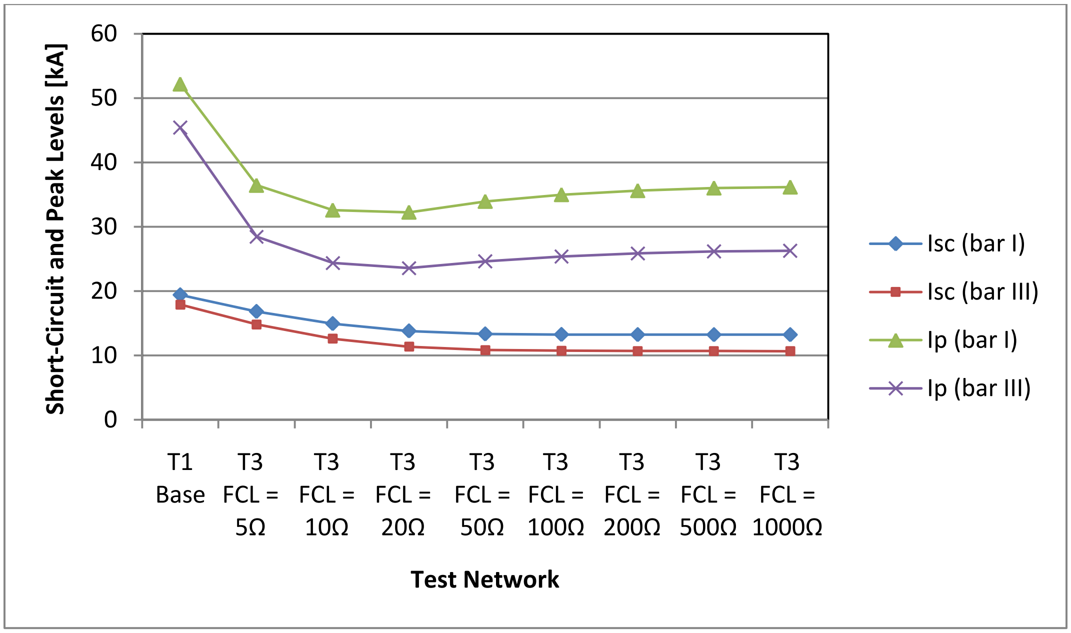


Chart 45: Fault levels at busbars I & III (FCL, T3).

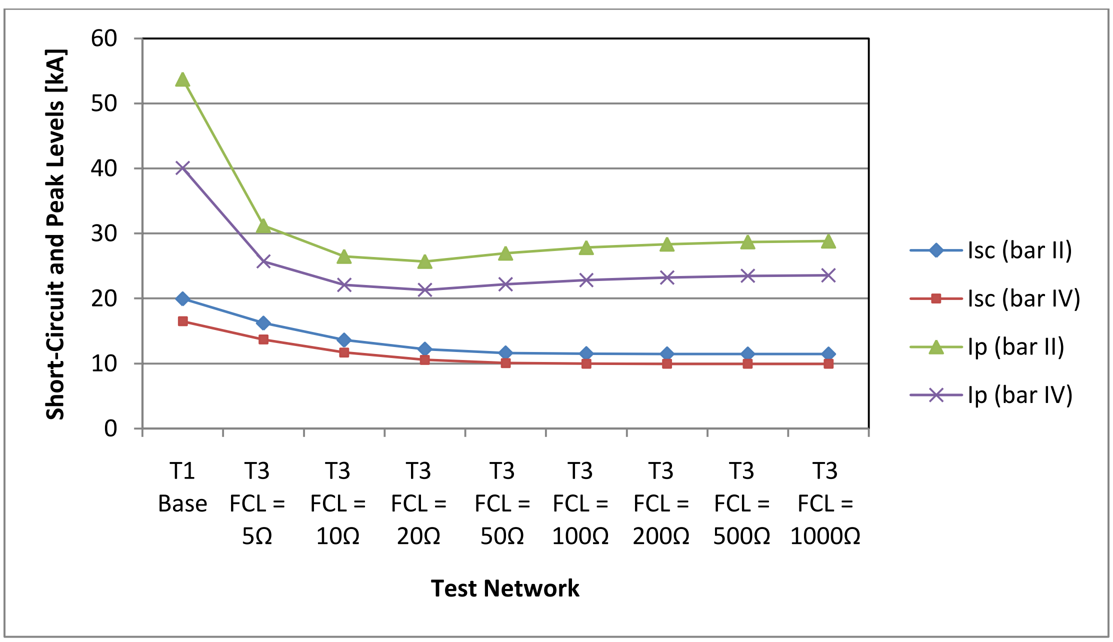


Chart 46: Fault levels at busbars II & IV (FCL, T3).

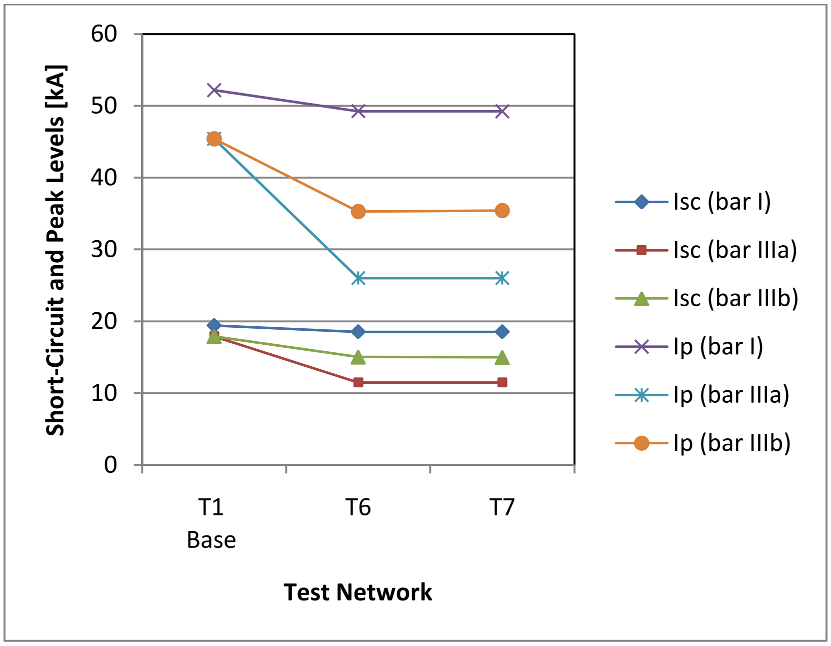


Chart 47: Fault levels at busbars I, IIIa & IIIb (split busbars, T6 and T7).

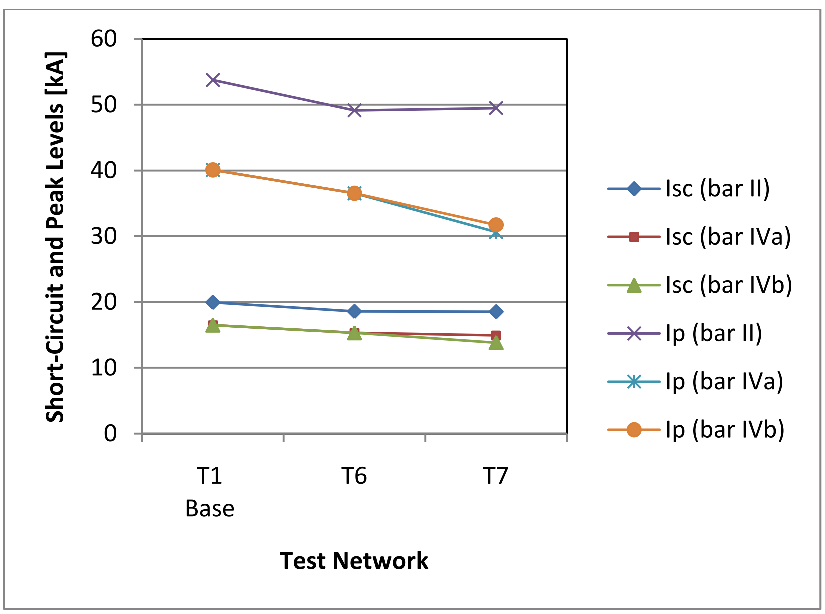


Chart 48: Fault levels at busbars II, IVa & IVb (split busbars, T6 and T7).

In **Charts 47** and **48**, note that for the base case (busbars were not divided) and for the case T6, the values at busbars IVa and IVb are the same (busbar IV was not divided).

Chapter 6: Discussion & Conclusions

6.1. Discussion

As an attempt to pursuit the most eligible techniques to implement fault current limitation and power flow control in parallel operation of underground cables and overhead lines, reliability and operational advantages, allied with network costs, must present high degree of correlation in comparison to the other cases. The simplicity of modifications in the network and how technically laborious and expensive they can be in order to provide the foremost performance have relevant importance in the choice. Moreover, the fulfillment of the (N-1) criterion and the elimination of interruptions to customers, thus optimized level of reliability, are priority in this study. Consequently, all cases that present interruption costs, due to power not supplied to customers, are not considered as eligible candidates, since only one fault were simulated *per* time.

6.1.1. Cost & Network Reliability

In part I, Network Cases (#1 to #52), it is inferred from **Charts 1** to **9** that the least costly networks were cases involving some level of redundancy in the configuration, such as looped or meshed systems. In fact, for the value of load considered, the presence of branches providing power from a second subsystem is enough to provide uninterrupted electricity from generation to load. Radial networks would not provide an uninterruptible path for power transfer in the cases of contingencies upstream to the subtransmission network, *i.e.*, in the transmission system. Under this situation, if one of the loads is not supplied, the costumer interruption cost for the event would be approximately 172,8 million euros. Alternatively, this value does not reflect the reality as an honest proposition and, therefore, is not presented in the results, for it considers subtransmission parameters.

Moreover, it is possible to identify that the networks with higher number of UGCs also present the most expensive investment and maintenance costs, drawing total network cost to higher levels. In **Chart 4**, for instance, comparing cases #22 and #23, integrally composed by OHLs and UGCs, respectively, it is possible to conclude how expensive UGC feeders can be, being roughly a threefold value more costly than to install only OHLs. In urban areas, utilization of UGCs represents several non-quantitative advantages and is assuredly more accepted by public opinion, nonetheless. Furthermore, losses cost in case #23 (UGCs) is only 3,93% of the total network cost, the smallest value in percentage of all network cases, while in case #22 (OHLs), this value is 32,01%.

In **Table 5**, it is possible to observe the comparison between the employed techniques (the cases comprising installation of devices or structural change of the base network). These values include all costs associated to the employed technique (running costs, equipment/technology and related ancillary equipment, such as circuit breakers, investment, equipment maintenance and loss). The least expensive cases were the ones using FCLs and series reactors.

In the upgrade cases (#51 and #52), it was considered the total cost of the conductor sections. On the other hand, fairer comparison would be the difference between the commonly employed UGC (Al800) and the upgraded UGC (Cu 1200). Therefore, the total attributed cost would be, for case #51, € 9 million (using Al 800) and € 9,91 million (using Cu1200); and for case # 52, € 12,05 million (Al800) and € 13,67 million (Cu1200).

In part II of the simulation, Test Network (T1 to T9), the total cost did not fluctuate much, being the difference of the most costly and the base case of about € 1,88 million. However, the investment related to the employed technologies and techniques varied significantly. The investment costs of the installed technology in each case were approximately: € 0,90 million (T2); € 0,90 million (T3); € 0,51 million (T4); € 0,55 million (T5); € 0,08 million (T6); € 0,16 million (T7); € 9,14 million (T8, UGC Cu 1200); and € 12,86 million (T9, UGC Cu 1200). Perhaps the investment cost represents a major factor in the choice of which technology or technique to install.

In terms of network reliability, the test network presents backup power supply (meshed configuration and transformers in reserve), thus fulfilling the (N-1) criterion. In this simulation, in which only one fault *per* time was introduced to the system (sustained faults, depending where in the network the fault happens, different repair times were considered, as described in **Appendix C**), the network responded well, providing power supply without compromising the thermal limits of UGCs even after the life cycle time when each of the two loads will be grown from 25 MVA each to 37,22 MVA.

For the considered loads, in the left part of the network (**Figure 2**, subsystem I, *i.e.*, the corridor linking transformer T_I to the load L_1), the presence of OHLs and 5 conductors feeding the busbar III creates redundant and robust supply. On the other hand, in the right part of the network (subsystem II, linking transformer T_{II} to load L_2), busbar IV is supplied by only two UGCs. In the case of losing one of these cables, due to routine equipment maintenance or contingency, only one of these cables withstands supply to the whole load. For the employed cable Al 800, it is within its themal and ampacity limits. Additionally, in the case of cable upgrade, the substitution of one of these two cables connected to busbar IV would represent the most advantageous contribution to the system. Or, similarly, by directly connecting this busbar to a second source point, for instance, coming from a third subsystem, could be a sensible alternative on the grounds of supporting a higher degree of reliability.

It is important to acknowledge the fact that by ramifying a network and introducing connections to more power sources increases short-circuit levels in busbars. In the case of this test network, that is an unwanted network side-effect.

From **Charts 13** to **22**, from both parts of the simulation, it is possible to verify normalized values in percentage. Running cost (*i.e.*, loss) in OHLs is major component of the total network cost. UGCs present much lower loss, since impedance is significantly smaller than in OHLs. On the other hand, in UGCs maintenance and investment costs, mostly originated from conductor installation, costs are typically threefold higher and, altogether, constitute over than 95% of the total feeder cost. From **Charts 11** and **12**, the cost *per* kilometer of conductor is targeted. Similarly, network cases with lower length of UGCs and presenting backup from a second subsystem is the most economically feasible alternative.

6.1.2. Power Flow & Parallel Operation of UGCs and OHLs

Despite the more attractive cost of the network configuration cases (cases #1 to #25), they do not solve the power flow problem in parallel operation of OHL and UGC. Indeed, by increasing the number of parallel feeders the distribution of currents is assured in a way that there will be less current passing through these feeders. Alternatively, on the case when one of these feeders is taken out of service, the share of load between them, particularly in the presence of UGCs and OHLs in parallel, can be dangerously uneven leading to cascade tripping.

When a UGC (Al 800) and a single circuit of OHL (Al/Fe 205/33) are operating in parallel, under normal network conditions, the current rate is 3,3 times larger in the UGC than in the OHL. Cascade tripping, caused by larger disturbances in the system, can also be caused by overload in feeders (gradual increase of power flow though a conductor). This is more susceptible to happen in the presence of parallel OHLs and UGCs. As a consequence of overloading, conductor thermal limits are surpassed activating protection. Consequently, all adjacent feeders trip leading to complete interruption of power supply.

To avoid that, reactive compensation has to be introduced to the network. Another choice is to create a network entirely compound of OHLs and UGCs, identical in impedance, which is not the case of the existing urban subtransmission networks. Series reactors were investigated in cases #31 to #42, in part I. The installation of series reactors in UGCs in parallel with OHLs were very effective bringing power flows to a more even level, thus limiting the possibility of cascade tripping due to overload. The level of compensation can bring cable reactance to the same level as line reactance.

Series reactors were installed to one single cable or to two parallel cables. This way, it is possible to compensate more than one cable and also diminish locally the short-circuit levels. However, this was observed at a small level, as seen in busbars III and IV from **Charts 39** and **40**.

Moreover, the usage of the TCSC in OHLs as reactive compensation also brought dynamic equalization of power flow between cables and lines. The presence of compensation harmonizes distribution of currents according to the real-time situation of the network. This is the major advantage of FACTS devices over non-compensated networks. Also, TCSC behaves as voltage regulator and provides flexibility to the compensated line (this happens by changing the degree of compensation provided by the power-electronic-based devices associated to this equipment). Also, local voltage boost was verified in busbars in TCSC-employed network cases.

Alternatively, TCSC investment is quite high in face with series reactors. The price *per* kVAr observed in TCSC is over than US$ 100, depending on the equipment power rate (in this theses, the value of € 80 was considered). For passive compensation, including series reactor and bank of capacitors, the value is of US$ 10 (€ 8, in this thesis). Further, the advantages of TCSC are more praiseworthy to longer high-voltage lines requiring voltage regulation than to subtransmission networks.

In the test network (part II), series reactors did not present as good balance of load as in the network cases. The compensation caused better current distribution only to the parallel UGCs to which the reactor was installed. For example, in the case T4, where a reactor was installed at the UGC connecting busbars II and IV, it is possible to select a compensation value at which the reactance of the compensated cable reaches similar value to the equivalent adjacent feeder supplying load L_2. Conversely, in case T3, where a reactor was installed in the two UGCs linking busbars II and III, the presence of this reactor increased the power flow through the UGC between busbars II and IV in over 20%. This case was discarded as eligible alternative to the test network.

Power flows in UGCs were beneficial in the split busbars cases (T5 and T6). Splitting busbar III in one point, first case, brought same values as splitting busbars III and IV in one point, creating evenly distributed current values in all UGCs (for UGCs between busbars I and IIIa-IIIb and between II and IVa and IVb, the passing current was identical). Not only the benefit of reducing short-circuit level in the split busbars, but also this technique distributed the power flow in the considered network more evenly.

6.1.3. Effect in Short-Circuit Levels at 110-kV Busbars

For the first part of the simulation, which is identifying the impact on short-circuit levels at busbars, it is possible to observe from **Charts 23** to **40** that a huge difference can be accomplished using different techniques. Radial networks present intrinsically lower short-circuit levels compared to other configurations, for the busbars are connected to one single feeder from transmission network. Looped and meshed networks present similar short-circuit levels, but different for peak short-circuit levels, once these numbers depend on the nature of network (strictly related to the Thévenin equivalent resistance and impedance ratio). This behavior can also be extended to the reactive compensated networks (TCSC and series reactor) in which fault levels are slightly smaller than the base-case networks that present no compensation.

The most effective alterations were experienced in the FCL and split busbar cases. In the first solution, short-circuit levels were decreased to nearly half of the base-case level using 50 Ω devices (resistive FCL). It is verified, as well, that after in these networks the value of 50 Ω, the short-circuit values stabilize; however, the equivalent Thévenin resistance at the short-circuit point (*i.e.*, in the busbars) causes the exponential decay, as in **Equation 34**, significantly faster. This effect can also be investigated using the equivalent of Thévenin using R_{FCL} equals to 5 Ω, 10 Ω, 20 Ω and 50 Ω. The decay happens abruptly faster for higher R_{FCL} values. When installed in the MV level, there is no significant effect on the subtransmission network, whatsoever, therefore not considered as viable solution in this thesis. Nonetheless, the short-circuit levels at MV busbars (**Charts 35** and **36**) for FCL installed at MV level – between transformers T_1 and T_2 and MV busbars – were decreased from 45 kA to about 3 kA using a 66-Ohm 20-kV device.

In the second part of the simulation, using different base values (*vide* **Appendix A**), the results obtained from the installation of FCL between busbar I and transformer T_I (T2) and busbar II and transformer T_{II} (T3) were very effective, presenting reduction in short-circuit levels up to 45%, as depicted in **Charts 43** to **46**. One other major advantage of employing this device is that it avoids the first cycle, *i.e.* the peak short-circuit value. Nonetheless the increase of the device cost by usage of larger amount of material (directly proportional to device price), the insertion of higher resistance values returns small decrease in the short-circuit levels. From the same graphics, values up to 1000 Ω were analyzed and it is possible to notice that there was minimal difference for device resistance values over than 50 Ω in all cases. On the other hand, this varies in different networks, since topology and short-circuit location affect current levels.

Recalling the fact that FCL devices avoid the first half-cycle peak (thus the peak short-circuit level) during a fault and withstand these currents during faulty conditions, this technology represents an outstanding advantage in face to other employed equipment and techniques. This technology, at high-voltage levels, is under development. However, it is worth develop further study to analyze the benefits of this device at subtransmission networks and the best allocation for optimal benefits.

In both parts of simulation, splitting busbars brought considerable reduction on short-circuit and peak levels on busbars III and IV (**Charts 37** and **38**), though no major changes on busbars I and II, as verified in **Charts 33** and **34**. Similarly in the test network (cases T6 and T7), the most significant differences were observed in busbars III and IV, from **Charts 46** and **48**. Additionally, higher reduction in short-circuit level was verified in case T6, in which only busbar III was modified. In busbar IV, there was no major change. This happens due to the meshed configuration of the particular test network.

As previously mentioned, in the test network, splitting busbars introduced a good level of power flow balance, giving to this alternative complete fulfillment of the three analyzed factors. Allied to the installation of a FCL, the association of these two techniques would bring a battery of benefits, at reasonably low cost (investment cost is floating, once it depends on how much a HV FCL will be available in the market), to the tested network.

Finally, shifting the base-case network to radial configuration by fast switching schemes, during faults, diminishes source contribution, thus decreasing short-circuit levels. Under normal operation, the meshed configuration is re-established providing lighter current values on UGCs. For that, substation automation and relaying apparatus must be prepared to operate under such situation and the presence of fast circuit breakers should be accounted to this change of network topology.

6.2. Conclusions

As conclusion, a wide set of interesting advantages is observed from different employed techniques. In urban areas where underground cables are more commonly employed than in less densely inhabited regions, UGCs in parallel with OHLs must be utilized introducing some restrictions to high voltage networks, particularly concerning thermal conditions and operational procedures.

A good solution to the test network (**Figure 2**) is the one that best fulfills the three following technical/operational constraints: diminution of short-circuit levels, low cost (extending to low investment) and even distribution power flow through the network. For that, splitting busbar – particularly for busbar III – or this technique in association with installation of FCL represent the most economically and technically viable solutions according to this study.

Splitting busbars achieves desirable results and is attractive because of its simplicity and interesting technique cost. It diminishes short-circuit level (only the changed busbars connected to distribution level, *i.e.*, downstream to the busbar, experienced significant changes), it offers the possibility to operate the network in different configurations, as for instance radially operated under contingency and meshed network under normal conditions by operational maneuvers from fast switching schemes.

The installation of FCL devices has presented large drop of short-circuit level, in average drops of 40%, and elimination of peak current. In addition, if equipment offers close to optimal reliability level, there is the possibility to decrease transformer impedance, therefore reducing loss in the circuit. On the other hand, this technology is under development and test phase for high voltage systems. Moreover, in the case of this study the equipment reliability was considered to be optimal (further description from **Chapter 3** and related references).

Consummately, all employed techniques, as for instance series reactors, are not exclusively interesting to the tested network, since no significant reduction on short-circuit level is provided to the busbars connected upstream the equipment (connected to the transmission network). On the busbars connected to the distribution network, there is insignificant reduction, not as distinct as the values uphold by FCLs and splitting busbars. Conversely, reactive compensation alternatives, such as series reactors and FACTS devices, provide better management of power flow locally and in the specific case of OHLs and UGCs operating in parallel circuits, these technologies are the main solutions, notwithstanding high investment and running costs.

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Appendices

Appendix A: Network Electrical Parameters

Appendix A.1: Network Cases (Part I, #1 - #52)

Bases: S_b = 1000 ; V_b = 110 kV;

I. Transmission Network (400 kV):

Transformer T_I: 500 MVA, 400/110 kV, j.0,15 pu

Transformer T_{II}: 500 MVA, 400/110 kV, j.0,15 pu

II. Subtransmission Network (110 kV):

Transformer T_1: 200 MVA, 110/20 kV, j.0,06 pu

Transformer T_2: 200 MVA, 110/20 kV, j.0,06 pu

III. Distribution Network (20 kV):

Load L_1: 100 MVA, 20 kV, pf = 0,95

Load L_2: 100 MVA, 20 kV, pf = 0,95

Appendix A.2: Test Network (Part II, T1 - T9)

Bases: S_b = 1000 MVA; V_b = 110 kV;

IV. Transmission Network (400 kV):

Transformer T_I: 100 MVA, 400/110 kV, j.0,03 pu

Transformer T_{II}: 100 MVA, 400/110 kV, j.0,03 pu

V. Subtransmission Network (110 kV):

Transformer T_1: 40 MVA, 110/20 kV, j.0,03 pu

Transformer T_2: 40 MVA, 110/20 kV, j.0,03 pu

VI. Distribution Network (20 kV):

Load L_1: 25 MVA, 20 kV, pf = 0,95

Load L_2: 25 MVA, 20 kV, pf = 0,95

Appendix B: Conductor Component Data*

110-kV Conductors	Conductor Cost [€/km]	Construction Cost[1] [€/km]	Total Price [€/km]	Maintenance Cost [€/km.a]	Rated Current [A]	Rated Power [MVA]	Resistance[2] [Ω/phase.km]	Reactance[3] [Ω/phase.km]	Earth-Fault Current [A/km]	Short-Circuit Withstand Current, 1s [kA]
110-kV overhead line, steel towers										
single circuit Al/Fe 106/25	9 072	120 528	129 600	1 000	430	82	0,273	0,410	0,32	10,0
single circuit Al/Fe 152/25	12 960	147 312	160 272	1 000	550	105	0,190	0,400	0,33	14,3
single circuit Al/Fe 205/33	12 960	174 096	187 056	1 000	660	126	0,145	0,390	0,33	18,9
single circuit Al/Fe 305/39	18 468	200 880	219 348	1 000	845	161	0,100	0,380	0,35	28,7
single circuit 2 x Al/Fe 305/39	36 936	219 897	256 833	1 000	1 280	244	0,049	0,270	0,35	28,7
single circuit Al/Fe 565/72	27 216	254 448	281 664	1 000	1 240	236	0,054	0,360	0,37	53,1
single circuit 2 x Al/Fe 565/72	54 432	281 232	335 664	1 000	1 880	358	0,027	0,260	0,37	53,1
double circuit Al/Fe 106/25	18 144	145 800	163 944	1 000	860	164	0,137	0,430	0,29	10,0
double circuit Al/Fe 152/25	25 920	178 200	204 120	1 000	1 100	210	0,095	0,420	0,30	14,3
double circuit Al/Fe 205/33	25 920	210 600	236 520	1 000	1 320	251	0,073	0,410	0,30	18,9
double circuit Al/Fe 305/39	3 636	243 000	246 636	1 000	1 690	322	0,050	0,400	0,32	28,7
double circuit 2 x Al/Fe 305/39	73 872	266 004	339 876	1 000	2 560	488	0,025	0,290	0,32	28,7
double circuit Al/Fe 565/72	54 432	307 800	362 232	1 000	2 480	473	0,027	0,380	0,34	53,1
double circuit 2 x Al/Fe 565/72	108 864	340 200	449 064	1 000	3 760	716	0,014	0,270	0,34	53,1
110-kV cables (PEX types AHXLMK and HXLMK)										
Al 300	129 000	600 000	729 000	2 000	390	74	0,125	0,132	9,90	28,3
Al 800	165 000	600 000	765 000	2 000	670	128	0,053	0,113	13,80	75,6
Cu 1200	300 000	600 000	900 000	2 000	1 100	210	0,019	0,110	16,80	171,1
Cu 2000	465 000	600 000	1 065 000	2 000	1 400	267	0,012	0,101	24,60	285,7

[1] Earthwork, cable channels & pipes, erection of towers and materials;
[2] typical values;
[3] typical values for reactance of cables in delta configuration.

Appendix C: Parameters & Technical Constraints*

Interest rate	6 %/a
Load growth	1 %/a
Load growth period	40 years
Life cycle	40 years
Discount Factors (load and costs increase constantly each year)	
k_{losses}	32,834
k_{load}	32,834
k_{EAC}	15,046
Peak utilization (T_{peak})	5000 h/a
Price of power losses (h_{pl})	5 €/kVA.a
Energy loss price:	
h_{w0} (no load losses)	0,03 €/kWh
h_{wk} (load losses)	0,04 €/kWh
Nominal voltage	110 kV
Repair costs:	
OHL faults	2000 €/fault
UGC faults	20000 €/fault
Others	100 €/h
Customer Interruption Costs (CIC):	
Agricultural	0,45 €/kW; 9,38 €/kWh
Commercial	2,65 €/kW; 29,89 €/kWh
Domestic	0,36 €/kW; 4,29 €/kWh
Industry	3,52 €/kW; 24,45 €/kWh
Public Service	1,89 €/kW; 15,08 €/kWh
Customer Interruption Costs (used value):	
Load 1, Load 2	a = 1,59 €/kW; b = 13,87 €/kWh, considering percentages of these 5 different types of customers distributed homogeneously.

Appendix D: Evaluation Parameters

Appendix D.1: Investment and Maintenance Costs*

Investment	Unit	Investment Cost [€/unit]	Annual Maintenance Costs [€/unit.a]	Equivalent Annual Costs [€/unit.a]
Switches and network automation				
manually controlled line disconnector	piece	3 000	75	274
remotely controlled disconnection station	piece	14 500	745	1 109
network circuit breaker	piece	30 000	300	2 294
network circuit breaker station (3 cbs + 3 disconnectors)	piece	68 000	680	5 199
TCSC	kVAr	100		4,00
[series] reactor	kVAr	10		0,80
FCL	piece	900 000	680	5 199
Conductor				
overhead lines	km	18 000	120	1 316
underground cables	km	40 000	50	2 708
earth-fault compensation (cable lines)	km	3 100	27	233

Appendix D.2: Component Failure and Repair Time**

Component	Total Failure Rate	Repair or Replacement Time [h]
110 kV busbars	0,0068 fault/a	200
110 kV circuit breakers	0,00336 fault/a	100
110 kV transformers	0,023 fault/a	300
110 kV overhead lines	0,0218 fault/km.a	48
110 kV underground cables	0,001 fault/km.a	336

***Source:** Hyvärinen, M., “Electrical Networks and Economies of Load Density”, Doctoral Dissertation, Helsinki University of Technology, Espoo (Finland), December 2008, 94 pp;

****Source:** Kazemi, S., “Reliability Evaluation of Smart Distribution Grids”, Doctoral Dissertation, Aalto University, Espoo (Finland), October 2011, 147 pp..

Appendix E: Annuity Factor Formulation

After 1 year payment S_a is accomplished, the owning money is:

$$x_1 = S_0(1 + p/100) - S_a$$

After 2 years:

$$x_2 = [S_0(1 + p/100) - S_a].(1 + p/100) = S_0(1 + p/100)^2 - S_a(1 + p/100) - S_a$$

After 3 years:

$$x_3 = \{[S_0(1 + p/100) - S_a].(1 + p/100) - S_a\}.(1 + p/100) - S_a$$

$$= S_0(1 + p/100)^3 - S_a(1 + p/100)^2 - S_a(1 + p/100) - S_a$$

After t years (Equation I):

$$x_t = S_0(1 + p/100)^t - S_a[1 + (1 + p/100) + (1 + p/100)^2 + \cdots + (1 + p/100)^{t-1}]$$

$$= S_0(1 + p/100)^t - S_a.A = 0$$

Being:

$$A = 1 + (1 + p/100) + (1 + p/100)^2 + \cdots + (1 + p/100)^{t-1}$$

Multiplying $(1 + p/100)$ by:

$$A.(1 + p/100) = (1 + p/100) + (1 + p/100)^2 + (1 + p/100)^3 + \cdots + (1 + p/100)^t$$

Substituting for A again:

$$A.(1 + p/100) = A - 1 + (1 + p/100)^t$$

Isolating A:

$$A - A.(1 + p/100) = 1 - (1 + p/100)^t$$

$$A = \frac{(1 + p/100)^t - 1}{p/100}$$

Substituting in Equation I:

$$S_0(1 + p/100)^t - S_a \frac{(1 + p/100)^t - 1}{p/100} = 0$$

$$S_0 = S_a \frac{1}{p/100} . \frac{(1 + p/100)^t - 1}{(1 + p/100)^t}$$

Resulting in:

$$\boldsymbol{S_0 = S_a \frac{1}{p/100} . \left[1 - \frac{1}{(1 + p/100)^t}\right]}$$

Being:

$$\delta = (1 + p/100)$$

Therefore:

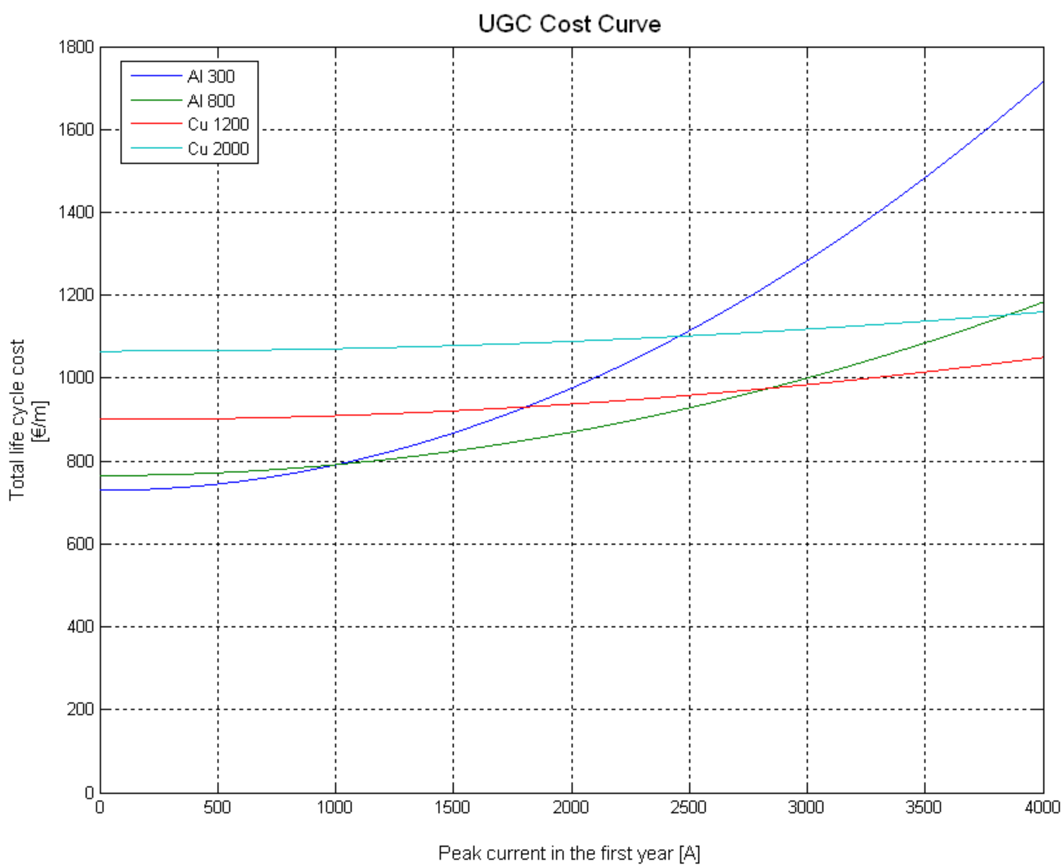
$$S_0 = S_a \frac{1}{p/100} . \left[1 - \frac{1}{\delta^t}\right]$$

And:

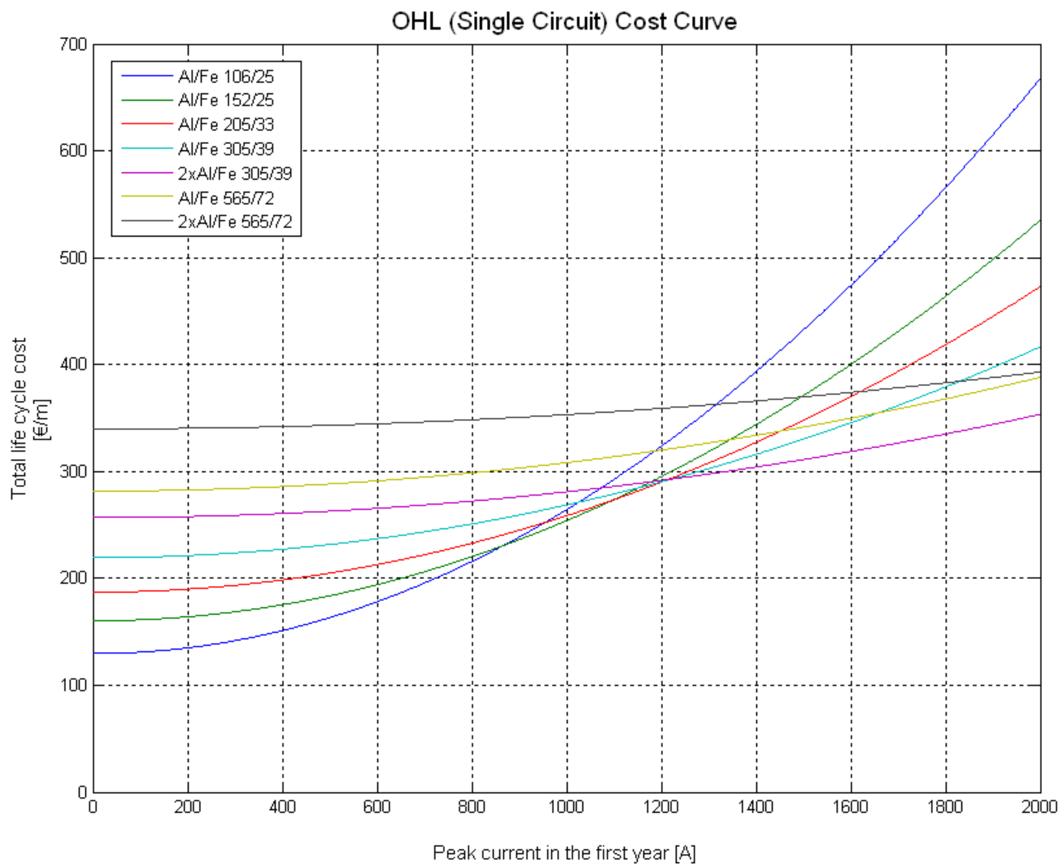
$$k_c = \frac{1}{p/100} . \left[1 - \frac{1}{\delta^T}\right]$$

Appendix F: Conductor Cost Curves

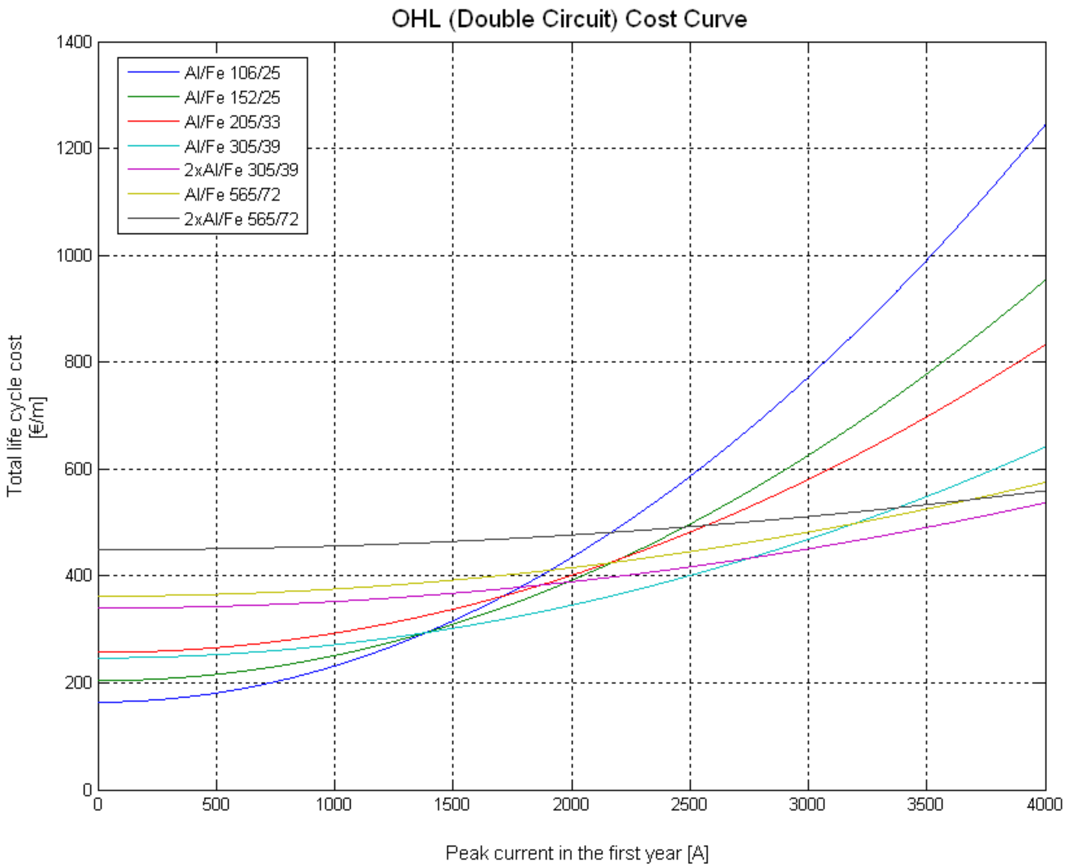
Appendix F.1: UGC Cost Curves



Appendix F.2: OHL (Single Circuit) Cost Curves



Appendix F.3: OHL (Double Circuit) Cost Curves



Appendix G: Simulated Cases

Appendix G.1.: (Part I: Network Cases)

Case	Network configuration	Bars					Total OHL [km]	Total UGC [km]
		I-II	I-III	II-III	II-IV	III-IV		
	Distance [km]	10,00	10,00	14,14	10,00	10,00		
	Base networks:							
#1	**Radial**		**2 OHL**		**2 OHL**		**40,00**	**0**
#2	**Looped**		**2 OHL**		**2 OHL**	**2 UGC**	**40,00**	**20,00**
#3	**Meshed**		**2 OHL**	**2 UGC**	**2 OHL**		**40,00**	**28,28**
	Improved networks:							
#4	Radial A		2 OHL + UGC		2 OHL + UGC		40,00	20,00
#5	Radial B		2 OHL + OHL		2 OHL + OHL		60,00	0
#6	Radial C		2 OHL + 2 UGC		2 OHL		40,00	20,00
#7	Radial D		2 OHL + 2 OHL		2 OHL		60,00	0
#8	Looped A	2 OHL	2 OHL		2 OHL		40,00	20
#9	Looped B	2 UGC	2 OHL		2 OHL		40,00	20,00
#10	Looped C		2 OHL		2 OHL	2 OHL	60,00	0
#11	Looped D		2 OHL		2 OHL	2 UGC	40,00	20,00
#12	Looped E	OHL	2 OHL		2 OHL	OHL	60,00	0
#13	Looped F	UGC	2 OHL		2 OHL	UGC	40,00	20,00
#14	Looped G	OHL	2 OHL		2 OHL	UGC	50,00	10,00
#15	Looped H	UGC	2 UGC		2 UGC	UGC	0	60,00
#16	Meshed A		2 OHL	2 OHL	2 OHL		68,28	0
#17	Meshed B		2 OHL	2 UGC	2 OHL		40,00	28,28
#18	Meshed C	UGC	2 OHL	2 UGC	2 OHL	UGC	40,00	48,28
#19	Meshed D	OHL	2 OHL	2 UGC	2 OHL	OHL	60,00	28,28
#20	Meshed E	OHL	2 OHL	2 OHL	2 OHL	OHL	88,28	0
#21	Meshed F	UGC	2 UGC	2 UGC	2 UGC	UGC	0	88,28

#22	Meshed G	OHL	2 OHL	OHL	2 OHL	OHL	74,14	0
#23	Meshed H	UGC	2 UGC	UGC	2 UGC	UGC	0	74,14
#24	Meshed I	2 OHL	2 OHL	OHL	2 OHL	OHL	84,14	0
#25	Meshed J	2 UGC	2 UGC	UGC	2 UGC	UGC	0	84,14
	Equipment installed:							
#26	FCL A (TI and busbar I)	UGC	2 OHL	OHL	2 OHL	UGC	54,14	20,00
#27	FCL B (TII and busbar II)	UGC	2 OHL	OHL	2 OHL	UGC	54,14	20,00
#28	FCL C (T1 MV side)	UGC	2 OHL	OHL	2 OHL	UGC	54,14	20,00
#29	FCL D (T2 MV side)	UGC	2 OHL	OHL	2 OHL	UGC	54,14	20,00
#30	**Base Case TCSC**	**OHL**	**2 OHL**	**UGC**	**2 OHL**	**UGC**	**50,00**	**24,14**
#31	TCSC A	OHL + TCSC	2 OHL	UGC	2 OHL	UGC	50,00	24,14
#32	TCSC B	OHL	2 OHL + TCSC	UGC	2 OHL	UGC	50,00	24,14
#33	TCSC C	OHL	2 OHL	UGC	2 OHL + TCSC	UGC	50,00	24,14
#34	TCSC D	UGC	2 OHL	OHL + TCSC	2 OHL	UGC	54,14	20,00
#35	**Base Case Reactor**	**UGC**	**2 OHL**	**UGC**	**2 OHL**	**UGC**	**40,00**	**34,14**
#36	Reactor A	UGC	OHL + UGC + Reactor	UGC	2 OHL	UGC	30,00	44,14
#37	Reactor B	UGC	OHL + UGC + Reactor	UGC + Reactor	2 OHL	UGC	30,00	44,14
#38	Reactor C	UGC	2 OHL	UGC + Reactor	2 OHL	UGC	40,00	34,14
#39	Reactor D	UGC	2 OHL	UGC	OHL + UGC + Reactor	UGC	30,00	44,14
#40	Reactor E	UGC	2 OHL	OHL	2 UGC + Reactor	UGC	34,14	40,00
#41	Reactor F	UGC	2 UGC + Reactor	OHL	2 OHL	UGC	34,14	40,00
#42	Reactor G	UGC	2 OHL	UGC	2 OHL	UGC + Reactor	40,00	34,14
#43	**Base Case Split**	**OHL**	**2 OHL**		**2 OHL**	**OHL**	**60,00**	**0**
#44	Split A (busbar III)	OHL	OHL + OHL		2 OHL	OHL	60,00	0
#45	Split B (busbars III & IV)	OHL	OHL + OHL		OHL + OHL	OHL	60,00	0
#46	Split C (busbar III)	UGC	UGC + UGC		2 UGC	UGC	0	60,00
#47	Split D (busbars III & IV)	UGC	UGC + UGC		UGC + UGC	UGC	0	60,00
#48	Split E (busbar III)	UGC	OHL + UGC		OHL + UGC	UGC	20,00	40,00
#49	Split F (busbars III & IV)	UGC	OHL + UGC		OHL + UGC	UGC	20,00	40,00
#50	**Base Case Upgrade**	**UGC**	**OHL + UGC**	**UGC**	**2 OHL**	**UGC**	**30,00**	**44,14**
#51	Upgrade A	UGC	OHL + UGC Upgraded	UGC	2 OHL	UGC	30,00	44,14
#52	Upgrade B	UGC	OHL + UGC	UGC Upgraded	2 OHL	UGC	30,00	44,14

Appendix G.2.: (Part II: Test Network)

Case	Network configuration	Bars I-II	I-III	II-III	II-IV	III-IV	Total OHL [km]	Total UGC [km]
	Distance [km]	10	10	14,14	10	10		
	Test network:							
T1	**Base Case**	**2 OHL**	**2 OHL**	**2 UGC**	**UGC**	**UGC**	**40**	**48,28**
T2	FCL I (between TI and busbar I)	2 OHL	2 OHL	2 UGC	UGC	UGC	40	48,28
T3	FCL II (between TII and busbar II)	2 OHL	2 OHL	2 UGC	UGC	UGC	40	48,28
T4	Reactor I	2 OHL	2 OHL	2 UGC + Reactor	UGC	UGC	40	48,28
T5	Reactor II	2 OHL	2 OHL	2 UGC	UGC + Reactor	UGC	40	48,28
T6	Split (busbar III)	2 OHL	2 OHL	2 UGC	UGC	UGC	40	48,28
T7	Split (busbars III & IV)	2 OHL	2 OHL	2 UGC	UGC	UGC	40	48,28
T8	Upgrade I	2 OHL	2 OHL	2 UGC	UGC Upgraded	UGC	40	48,28
T9	Upgrade II	2 OHL	2 OHL	UGC + UGC Upgraded	UGC	UGC	40	48,28

Conductor in **bold**: base case (taken as reference for the related cases)

Highlighted *locus*: equipment or technique applied to respective conductors

Conductor in blue: changed conductor in comparison to base case

Conductor in green: added conductor in comparison to base case