TAMPEREEN TEKNILLINEN YLIOPISTO

VIIVI NAAKKA

RELIABILITY AND ECONOMY ANALYSIS OF THE LVDC DISTRIBUTION SYSTEM

Master of Science Thesis

Examiner: Professor Pertti Järventausta
Examiner and topic approved in the Computing and Electrical Engineering Faculty Council meeting on 7. December 2011

ABSTRACT

TAMPERE UNIVERSITY OF TECHNOLOGY
Master's Degree Programme in Electrical Engineering
NAAKKA, VIIVI: Reliability and economy analysis of the LVDC distribution system
Master of Science Thesis, 71 pages
February 2012
Major: Power systems and markets
Examiner: Professor Pertti Järventausta
Keywords: LVDC, distribution network, direct current, direct current transmission, electricity distribution, reliability of distribution, electricity quality

As electrical networks are developing towards smart grids, the network companies are discovering new affordable solutions as an alternative for 20 kV overhead line constructions and cabling, especially in the rural areas where the loading is not very high. The LVDC technology is a competitive option, as with it can be used materials designed for low voltage AC networks like cables and it offers a better weatherproof than overhead lines.

There are few options how the LVDC technology can be applied. The LVDC system can be build either uni- or bipolar and the converting can be either consumer specified or in links. The converting of AC to DC and the opposite can be done by using diode, thyristor or IGBT converters. There are only few things that limit the use of LVDC systems in distribution networks and they are the Low Voltage directive and the standard SFS-EN 50610.

So far there have been few LVDC test systems in Finland one in LNI's (former Vattenfall's) network and the other one in Suur Savon Sähkö network. The test results from two systems have been informative. The test systems have also proved that power electronic devices are compatible with the present network systems and with them the power quality can be improved.

The reliability of the LVDC systems is not as good as the 20 kV cabling, but it is better than the 20 kV overhead lines when comparing the annual interruption costs of MV feeders. There is still though an uncertainty factor in the reliability because it has been estimated for on the basis of reliability figures collected from the industrial use of converters.

In the comparison of lifetime costs, the costs under observation in this study are the investment costs, the maintenance costs, cost of losses, fault repair costs and interruption costs. The costs mentioned earlier are calculated using either the average prices of LNI or established values among the distribution network companies or using unit costs determined by authority. The observation period and expected lifetime used in calculations is 40 years.

As a result of the lifetime cost calculations, 20 kV cabled network on the MV feeders under observation, is at the moment the best solution to rebuild the networks. The gap between 20 kV cabling and LVDC systems is not big and the issues can be solved. The main issues to solve are: the energy efficiency of the LVDC system, the actual reliability of the converters and the technical solution of galvanic isolation. The reason for the energy efficiency and the reliability to be the cause of uncertainty is only the fact that there is not any reliable data and experiences in the electricity distribution network use. The uncertainty can be removed after few years of testing LVDC in distribution networks and developing the energy efficiency of the converters.

TIIVISTELMÄ

TAMPEREEN TEKNILLINEN YLIOPISTO
Sähkötekniikan koulutusohjelma
NAAKKA, VIIVI: LVDC jakelujärjestelmän luotettavuuden ja taloudellisuuden analysointi
Diplomityö, 71 sivua
Helmikuu 2012
Pääaine: Sähköverkot ja markkinat
Tarkastaja: professori Pertti Järventausta
Avainsanat: LVDC, sähkön jakeluverkko, sähkönjakelu

Sähköverkkojen kehittymisen myötä sähköverkkoyhtiöt ovat alkaneet etsimään kustannustehokkaita vaihtoehtoja korvaamaan eliänikänsä päähän tulleita verkkoja. Toimitusvarmuutta ja säävarmuutta pidetään tärkeimpinä suunnittelua ohjaavina tekijöinä kustannusten ohella. Tämän työn tarkoitus on selvittää minkälaisen vaihtoehdon pienjännitteinen tasasähkön jakelujärjestelmä tarjoaa perinteisten 20 kV, ilmajohtojen ja kaapeloinnin rinnalle. LVDC-jakelu on ajateltu erityisesti maaseudulle kevyesti kuormitettujen 20 kV haarajohtojen korvausmenetelmäksi kaapeloinnin ja ilmajohtojen sijaan. LVDC-jakelujärjestelmä pystytään toteuttamaan joko uni- tai bipolaarisena sekä siten, että vaihtosuuntaus on keskitettyä tai asiakaskohtaista. Tasa- ja vaihtosuuntaus pystytään toteuttamaan diodi-, tyristori- tai IGBT-suuntaajilla.

Suomessa on tällä hetkellä muutamia testijärjestelmiä, joilla testataan LVDC-jakelua käytännössä. Näiden testijärjestelmien tarkoitus on testata kuinka tehoeleketroniikka toimii osana sähkönjakeluverkkoa ja kerätä kokemuksia laitteiston toiminnasta. Sähkön laadun paraneminen asiakkaan liittymispisteessä on eräs merkittävimmistä hyödyistä, joka testijärjestelmien avulla on havaittu.

LVDC-järjestelmän luotettavuus ei yllä aivan samalle tasolle kuin sähköverkkojen maakaapeloinnissa, mutta on parempi kuin ilmajohtoverkoissa. Tästä johtuu, että keskeytyksestä aiheutunut haitta (KAH) kustannus on suurempi LVDC:llä kuin maakaapeloinnilla tarkasteluissa toteutetuilla keskijännitelähdöillä. Laskennan pohjatietoina on käytetty teollisuudesta kerättyjä luotettavuusparametreja suuntaajille. Tästä johtuen on vielä epävarmaa, minkälaiseksi suuntaajien luotettavuus muodostuu todellisuudessa sähkönjakeluverkoissa, missä olosuhteet eroavat teollisuudesta.

Elinkaarikustannuksiin on huomioitu investointi-, häviö-, ylläpito-, viankorjaus- ja keskeytyskustannukset. Laskennassa on käytetty yleisesti sähköverkkoalalla käytössä olevia arvoja, EMV:n listahintoja sähköverkon komponenteille tai LNI verkon omia hintojen keskiarvoja. Tarkasteluajaksi ja laitteiden oletetuksi käyttöiäksi on valittu 40 vuotta. Elinkaarikustannusten laskennassa selvisi, että tarkasteltaville lähdöille haarajohtojen kaapelointi on kokonaiskustannuksiltaan edullisin vaihtoehto. LVDC järjestelmien kokonaiskustannukset eivät ole merkittävästi suuremmat, mutta kun huomioidaan, että todellisia ylläpito- ja investointikustannuksia ei kaikkia tiedetä on ero selkeä. Suurimmat haasteet LVDC-järjestelmissä on niiden energiatehokkuuden ja suuntajien luotettavuuden parantamisessa sekä galvaanissa erottamisessa asiakkan ja sähkönjakeluverkon välillä. Todellisia huoltokustannuksia ei LVDC-järjestelmälle myöskään tiedetä, joten sekin on eräs epävarmuustekijöistä. Nämä epävarmuustekijät ovat kuitenkin ratkaistavissa ja pienillä parannuksilla LVDC-järjestelmästä tulee kokonaiskustannuksiltaan edullisempi kuin 20 kV kaapelointi kevyesti kuormitetuilla haarajohdoilla.

PREFACE

This master's thesis was written for LNI Verkko Oy (former Vattenfall Verkko Oy) and it was part of SGEM program. I would like to thank Professor Pertti Järventausta of guidance and constructive feedback during the thesis work. I would also like to express a huge gratitude to my thesis instructor Tommi Lähdeaho from Vattenfall Verkko Oy.

This master's thesis is part of Cleen's (Cluster for Energy and Environment) SGEM (Smart Grids and Energy Markets) project.

Tampere 22.02.2012

Viivi Naakka

CONTENTS

TERMS AND DEFINITIONS

Abbreviations

AC	Alternative current
AMKA	Type of arial bunched cable
AMR	Automatic meter reading
CAIDI	Customer average interruption duration index
DC	Direct current
DG	Distributed power generation
EMV	Energy Market Authority
GPRS	General Packet Radio Service
HV	High voltage
HVAC	High voltage alternative current
HVDC	High voltage direct current
IGBT	Insulated Gate Bipolar Transistors
LCL	Inductor-capacitor-inductor
LUT	Lappeenranta University of Technology
LVAC	Low voltage alternative current
LVDC	Low voltage direct current
MAIFI	Momentary average interruption frequency index
MTBF	Mean time between failures
MTTR	Mean time to repair
MV	Medium voltage
NCP	Neutral point clamped-inverter
RNA	Reliability based network analysis
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory Control and Data Acquisition
SGEM	Smart grids and energy markets –project
THD	Total harmonic distortion

Lower indexes

ajk	delayed autoreclosure
cable	cables resistance
drop	voltage drop
loss	losses
Lt	long term
n	nominal
pjk	short autoreclosure
rms	root-mean-square value
St	short term

1 INTRODUCTION

The society has become more and more dependent on the distribution of electricity and its demand has increased as well. So it is no wonder that the distribution companies and consumers want their electricity distribution to be more reliable and better quality than it has been before. From this need the interest towards DC systems have emerged.

At the beginning of the development of electrical networks over 100 years ago there was a competition between AC and DC systems and as we all know the AC system won and it became the dominant form. It won because its benefits were bigger than the barriers. Back then the DC distribution had more difficulties than advantages. Now time has passed and the interest towards DC distribution has grown again. The new development began from the need to transfer large amounts of power across large sea or between different frequency areas. Transferring huge amounts of power in AC cables is not possible so it was the beginning of the High Voltage Direct Current (HVDC) power transfer systems. The building costs of the HVDC systems have been much greater than HVAC so the HVDC has been used only in special occasions where the HVAC has not been possible.

The future trends in electrical distribution networks are developing them towards smart grids and distributed generation (DG). Due to this there has emerged a need to discover new and more efficient ways to deliver electricity to the consumers and discover possibilities to attach the DG to the distribution networks. This trend has also supported the idea of utilizing low voltage direct current (LVDC) system in distribution networks the same way it has been used in power transfer in the high voltage networks. The LVDC technology also enables small scale distributed generation units attachment to the distribution networks as a part of the DC-bus. The LVDC system with batteries and DG attached can create a small scale island grid if necessary.

Today as the material costs of copper, iron and other metals are increasing the distribution network companies have become more and more interested in new cheaper distribution solutions. Other significant factor is the constantly decreasing costs of electronic devices and their growing efficiency. The electronic DC devices like rectifiers and inverters have their downsides as well. Compared with the traditional distribution transformers 40 year lifetime, the rectifiers and inverters do not come even close, and they need more maintenance during their lifetime.

1.1 Objectives and scope of the thesis

Compressed to one sentence this master's thesis purpose is to find out is it financially and technically beneficial to start building and designing LVDC distribution systems as a part of and as a replacement for the existing distribution network. The study consists of four larger topics all of which have an effect on the total benefits of the system. Four topics are: the reliability of the LVDC system, power quality and reliability of the whole distribution network and the economic analysis of the LVDC system. These four main topics also build from smaller topic entities.

Underneath there is a somewhat more detailed description of this thesis purpose and the main aspects. The aims are to analyse the LVDC system's possibilities as a reinvestment for the traditional 20 kV branch lines, cabling and to examine the DC systems effects on the quality of supply and to find out the effects on the whole networks reliability. All of the points above will be viewed from LNI Verkko's point of view.

In Figure 1.1 is a view of the traditional distribution systems. At the bottom edge of the figure is illustrated the basic structure of 20 kV cabled branch line. In the middle of the figure is shown the basic structure of 1 kV branch line and on the top edge of the figure is shown the traditional 20 kV overhead branch line.

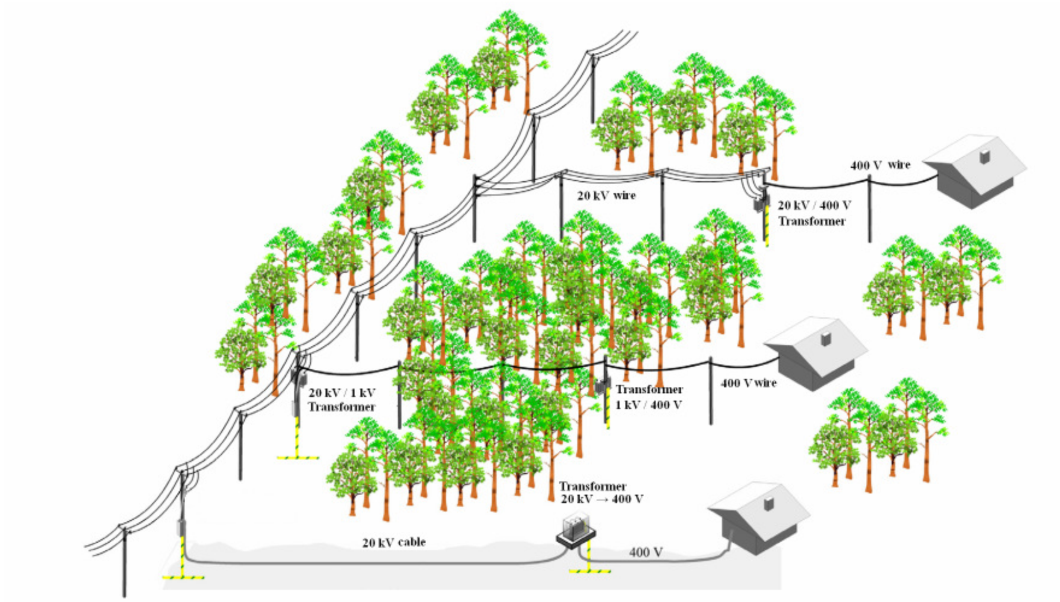

***Figure 1.1**. Traditional distribution network solutions.*

The main analyse emphasizes in the cost efficiency and reliability of the LVDC system. In Figure 1.2 there is an illustration of the LVDC systems principal.

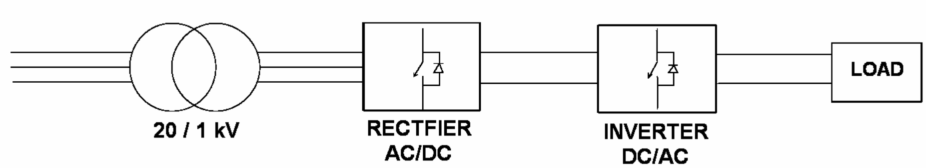

***Figure 1.2.** The principle structure of LVDC- system. (Rekola 2009)*

The focus of this study is in utilising the DC system as a part of the distribution network. This means that the voltage has been limited to medium and low voltages. The DC system also offers possibilities in high voltage transfer networks, but it is left out of this study.

The LVDC system is compared with the traditional 20 kV overhead lines and with 20 kV cabling but 1 kV overhead lines and cabling is left to a less attention. This is because it was found unsuitable for LNI's network. The reasons for the unsuitableness are discussed later in chapter five. Also the comparison between the LVDC system and the 1 kV system have been left to less observation because there are not any of 1 kV systems in the distribution network of LNI and due to that it is not considered necessary.

1.2 Thesis contents

Below there is a small introduction to the subject of the study. In the second chapter, the actual LVDC system is described in theory. The possibilities created by the LVDC distribution are also described in chapter two. It consists of introduction of the possible LVDC distribution solutions. More specific inspection of the test pilot system in LNI's distribution network, and a description of the becoming test pilot system are discussed in chapter three. In chapter three, the power quality is handled with the examples collected from the test pilot systems.

The fourth chapter discusses the reliability of the LVDC system. It has two main points of view: The reliability of the DC components and the reliability of the distribution. .

Then in fifth chapter there is an overview of the expenses of each distribution system. For example the construction costs and the outage costs are calculated for each model. Finally in sixth chapter there is an analysis of the LVDC systems lifetime costs and quality effects. In addition there is the last chapter which concludes the whole study.

2 THEORY OF LVDC DISRIBUTION SYSTEMS

In this chapter, there is an introduction to the theory of the LVDC systems and to their variations. First there is a review of the LVDC system requirements, like what standards it must full fill and so on. After the general requirements, the possible variations of the LVDC system topologies are introduced.

Low voltage system limits have been set by the European Union's low voltage directive LVD 2006/95/EC. In the directive low voltage has been limited to 1 kV in AC systems and to 1,5 kV in DC systems. The main requirements set by standards are described later in this chapter.

2.1 General system requirements

Before LVDC systems can be built the functionality requirements for the system needs to be defined, the key functionalities of them are listed below (LUT 2007):

- Purpose and conditions
- Power electronics modules input and output voltages and their fluctuation limits
- Power range, efficiency requirements
- Power and voltage endurance
- Electrical safety and protection
- Harmonic control
- Maintainability, lifetime
- Product and production standards, price

In addition, can be defined the following less critical additional functions:

- Data access needs
- Registration, repair and maintain of the quality and reliability of supply
- Energy measurements and their quality
- Connectivity options for distributed generation

All of the points above are discussed later in this master's thesis. Some of the requirements are not completely definable because there is not enough long term study and data of the LVDC systems.

2.2 Limits set by standards

The DC distribution system can be built in either two-wired unipolar connection or three-wired bipolar connection (SFS-6000-1 2007). These two systems are described more detailed later in this chapter. In the LVDC systems the voltage difference between two wires can be 1500 V according to the low voltage directive. The present cable standards SFS- 4879, 4880, 5800 and 5546 limit the maximum DC voltage used in uni-polar connections to 900 V and in bipolar connections to ±750 V. AMKA conductors cannot be used to DC power transmission at the moment because there are not DC voltage limits for them in the cable standards.

As the voltage limits are higher for the DC transmission, it enables more power transfer than in AC transmission when the transfer distance is the same. The LVDC distribution system needs to be fed by a low voltage AC system, so it can be considered as a low voltage DC system according to the following standards SFS-6000-1 and SFS-EN-50160. In practice this means that the distribution networks 20 kV transfer voltage must be decreased at least to 1 kV by a transformer before rectification. According to standard SFS-6000-1 the ripple in DC voltage must remain under 10 % of the nominal voltage so the voltage can be determined as DC.

The customer end voltage has established in Finland to the 230 V line to ground and 400 V line to line, 50 Hz sinusoidal alternating voltage. The customer end voltage fluctuation limits are the same no matter which distribution system is used, LVDC or LVAC, in this study the customers' voltage will be LVAC. The fluctuation limit is Un ± 10 % (SFS-EN-50160 2008). According to standard SFS 50160 the frequency should stay between the following limits: 50 Hz ± 1% 99,5 % of year and 50 Hz +4%, -6% 100% of the year. Though it is recommended to stay within the same limits as the main transmission grid: 50 Hz ±0,2 %. As most of LNI's customers are household consumers the flickering is also one thing that needs to be paid attention to. The hindrance of flickering is measured by the flicker severity index in two different times P_{st} short term and P_{lt} long term. (LUT 2007) All of the limits set by the standard SFS-EN 50160 are listed in Table 1.1.

Table 1.1. *Limits of the SFS-EN 50160 standard (adapting Mäkinen 2010).*

Feature	SFS-EN 50160	EN 61000-2-2
Frequency	50 Hz ± 1%,: 99,5% of 10 s average in year. +4%/-6%: 100% of the time	± 1Hz = 50 Hz ± 2%
Distribution voltage	U_n = 230 V	
Variation of voltage	Un ± 10%, during a week 95% on 10 min rms +10/-15%: 100% of the time	
Quick changes in voltage: - extent - flicker severity index	Usually < 5%. ...10% few times a day in some circum-stances. P_{lt}≤1 95% of the week	…3% normally >3% seldom In some occasions ±10% P_{st} = 1, P_{lt} = 0,8
Voltage dip	Most of <1s, <60% ΔU, In some areas 10-15% very often (...1000/a)	Informative appendix: In cable network 10-100 / a
Short interruptions	Tens to hundreds per year aprox. 70% < 1s.	
Long interruptions	< 10...50 kpl/a, > 180 s	
Temporary over voltages in operating frequency between conductor and ground	< 1,5 kV	
Transient over voltages between conductor and ground	Usually < 6 kV, sometimes over	Informative appendix: …2 kV typical …6 kV and over recorded
Asymmetry in distribution voltage	Negative sequence component 0-2%, during a week 95% of 10 min rms	negative sequence compo-nent 0-2%, 3% in some areas
Harmonic distortion in voltage	6% 5., 5% 7., 3,5% 11., 3% 13. and so on. THD ≤ 8%	6% 5., 5% 7., 3,5% 11., 3% 13. THD ≤ 8%
Inharmonic distortion in voltage	In consideration	P_{st} = 1
Signal voltages in net-work	0,1-0,5 kHz 9% 0,5-1 kHz 5-9%, 1-10 kHz 5%, 10-100 kHz 1-5% 99% a day from 3 s. values	110-3000Hz: 2-5%, 0,1-0,5 kHz 9%, 0,5-1 kHz 5-9%

The total distortion in current and voltage must remain less than 5% of the nominal value (LUT 2007). Because of this, the power factor of inverter's AC output must be between 0,8-1,0. To reach these values there needs to be sufficient filters which are acting with the inverter's modulation (LUT 2007). If there would be an interruption in distribution in 20 kV networks, the restart of the converters should happen controlled (Rekola 2010). The limits of harmonics in voltage are listed in Table 1.2.

Table 1.2. *Harmonic voltages maximum values in customers' interface until the ordinal number of 25 as a percentage of the nominal voltage U_n (Rekola 2009).*

Odd harmoics				**Even harmonics**	
Indivisible by 3		Divisible by 3			
Ordinal number n	Relative voltage	Ordinal number n	Relative voltage	Ordinal number n	Relative voltage
5	6 %	3	5 %	2	2 %
7	5 %	9	1,50 %	4	1 %
11	3,50 %	15	0,50 %	6 - 24	0,50 %
13	3 %	21	0,50 %		
17	2 %				
19	1,50 %				
23	1,50 %				
25	1,50 %				

According to IEC 606641-1, all the electrical devices connected to the distribution or home electricity network must withstand certain voltage impulses. Equipment in 750 voltage level must stand at least 12 kV voltage impulses. The normal IGBTs of the converters does not survive so high voltages, so there needs to be surge arresters of some kind. In bipolar DC systems, both voltages levels need their own protection devices of their own. (IEC 60644-1 2002; LUT 2007; LUT 2008)

2.2.1 Possibilities created by the LVDC system

As the LVDC distribution systems develop it will enable many things and it supports the idea of smart grids. The LVDC distribution systems create a possibility to add DG to the DC bus. It also enables the use of batteries or other energy storages.

The LVDC-links form their own protection area which in practise means that if there would be a fault somewhere in the LVDC-link it will not affect the whole MV-feeder as if the fault would be in 20 kV cable. The LVDC-systems have a positive effect on power quality this subject is described more detailed in Chapter 3.

The adding of DG and energy storages creates a possibility to use the network as an island in case the feeding network collapses. When the DG and storages are connected to the DC bus, there will not be any frequency synchronization problems like when the traditional AC-network is used as an island network.

2.3 Unipolar system

Unipolar DC system uses only one voltage level through which the power is transmitted. The system requires at least a two-wired-cable where the other is the phase conductor and the other return conductor. On both ends of the DC-link there are the needed converters, in Figure 2.1 on the left is the rectifier and on the right is the inverter. In unipolar systems the maximum voltage between conductors is limited to 900 V when it could be 1500 V within the framework of the low voltage directive. The 900 V limit comes from the cable standards listed in this chapter earlier. The actual used voltage level depends on how long is the used cable and which is the power ranges of the converters. In Figure 2.1 is a simple model of the unipolar DC-link. (Salonen 2006)

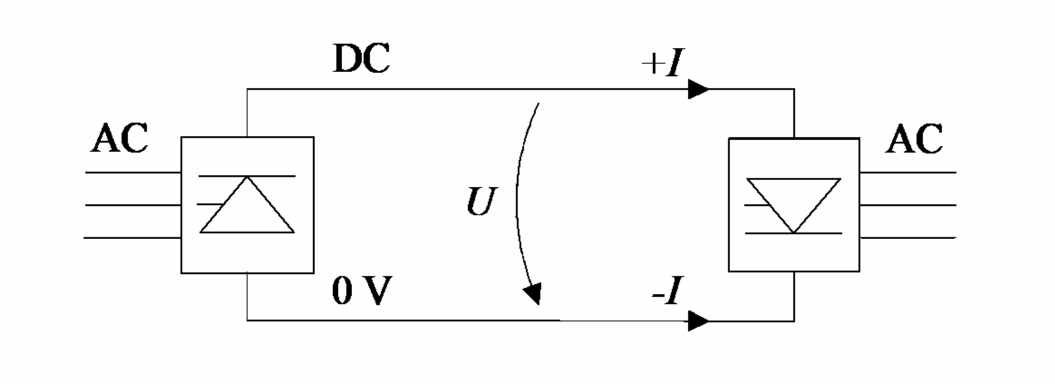

Figure 2.1. *A simple model of a unipolar dc system using a two-wired cable (Salonen 2006).*

In the 20 kV main supply end of the DC-cable, there is the small voltage transformer and right after it, the rectifier. On the other end of the DC cable, there is the inverter. In Figure 2.2 is a model of the unipolar LVDC system as a part of the distribution network.

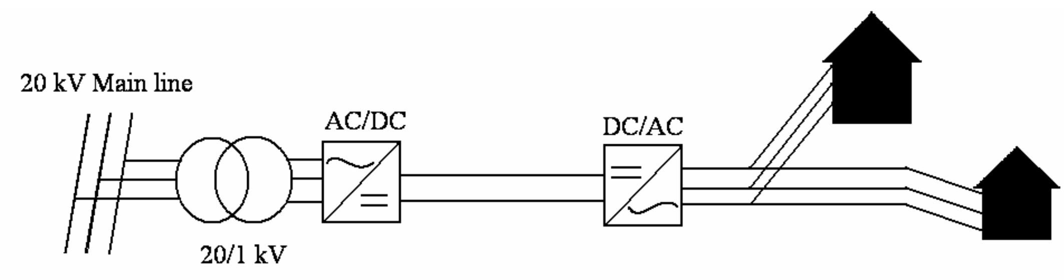

Figure 2.2. *A model of unipolar dc distribution system (Salonen 2006).*

2.4 Bipolar system

In bipolar systems two voltage levels are used, which are the same but opposite polarities. Bipolar system needs at least a three-wired-transfercable where one of the wires is the common zero voltage. In other words, every voltage level needs its own conductor. In Figure 2.3 is a model of the basic structure of the bipolar system. (Salonen 2006)

The converters in bipolar systems consist of two different converter modules which are connected between the zero voltage level and the other voltage level like in the figure 2.3 (below). The structure of the converters needs to be exactly the same in both units. The converter units can be the same as used in the unipolar systems. (Salonen 2006)

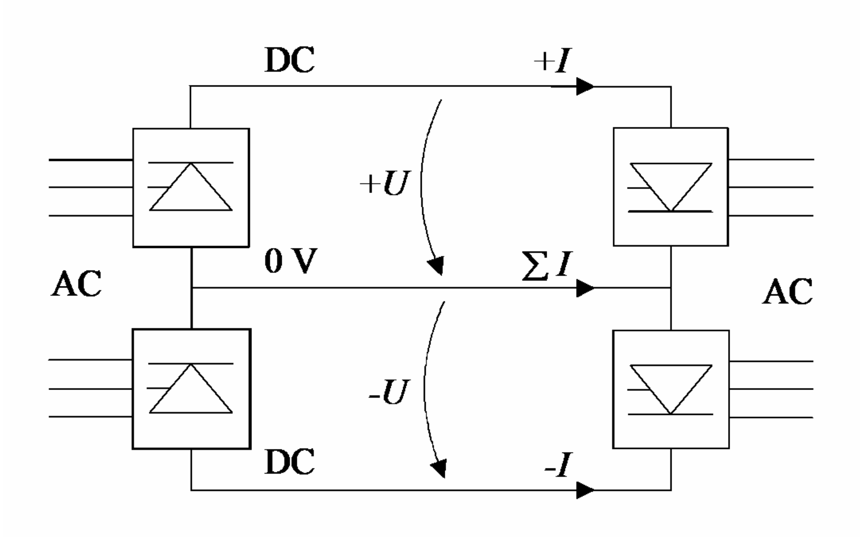

Figure 2.3. *A model of bipolar dc system using a three-wired cable (Salonen 2006).*

In Figure 2.4 is an example of how bipolar system could be utilized as a part of the distribution network. In Figure 2.4 are shown the possible clutching solutions: The inverter connected between DC voltage level and zero level (1 & 2), the inverter connected between two DC voltage levels (3) and the inverter connected to two DC voltage levels and to the zero level.

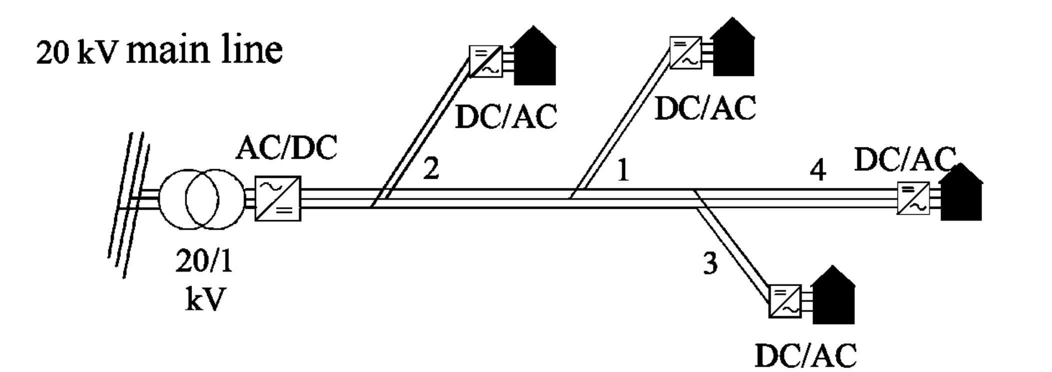

Figure 2.4. *A model of bipolar DC distribution system where customers interface is built between DC voltage and zero level (no. 1&2), between two DC voltages (no. 3) or in three phase DC (no. 4) (Salonen 2006).*

2.5 Consumer-specific DC-AC converting

One of the possible ways to implement the LVDC system is to place the DC/AC converter as a part of the customers' house installations. Then the customers' electricity interface could be either one phase AC or three phased AC. There are many different ways of constructing the consumer specific DC/AC converting systems. The possibilities are shown in Figure 2.4.

2.6 DC -link distribution system

The LVDC link system is one of the possible methods of using LVDC technology as a part of distribution networks. Its basic structure is shown in Figure 2.5. The link system consists of: a transformer that is used to lower 20 kV transferring voltage into a low voltage under 1 kV (1), the rectifier that turns the low voltage AC into low voltage DC (2), the low voltage cable (3), inverter which makes the DC into AC (4) and the low voltage AC cable which transfers the electricity to the customers (5).

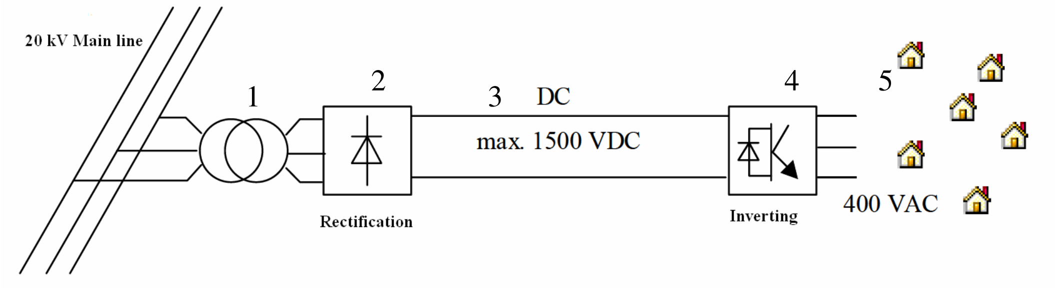

Figure 2.5. *An example of unipolar DC-link (LUT 2008).*

The linked LVDC system can also be constructed as a bipolar system as well. It could be utilized the same way as in Figure 2.5 or it is even possible to utilize for power transmission between two 20 kV lines like shown in Figure 2.6.

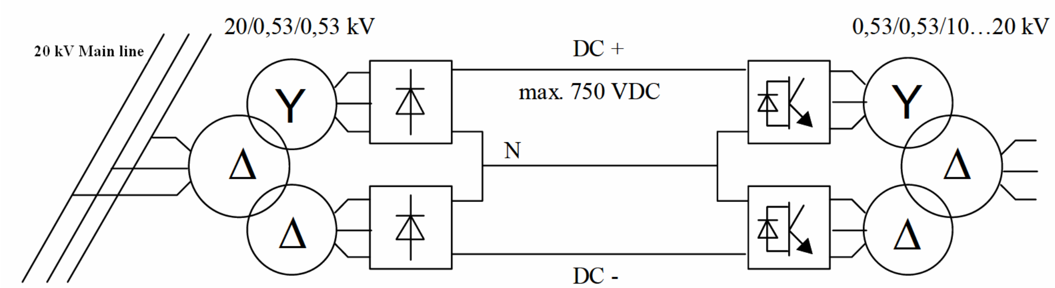

Figure 2.6. *An example of bipolar DC-link in 20 kV network (LUT 2008).*

The LVDC link can be built the way that it is able to transfer power in only one direction or in both directions. One way power transfer solution is simpler and cost efficient to build than the system that can transfer power in both directions. Bidirectional power transfer would require an extra inverter and rectifier which are connected parallel to the converters in one way power transfer when using diode or thyristor converters. Bidirectional LVDC-link would be alleged to build when there is a lot of distributed generation available in the area. (LUT 2008)

LVDC-link can also be built to connect LV-transforming circuits to each other and between MV networks to LV networks. The LVDC-link on the other hand does not adapt to power transfer between HV- and MV- networks because it has a limited power transfer range. The idea of using LVDC-connection between two LV-transforming circuits is to create a low voltage reserve connection. The reserve connection could be used for example in case of line breakage. (LUT 2008)

2.7 Grounding

One of the most important points of introducing this new technology is to make sure that it is safe. When talking about safety in electrical matters, it usually means the safety of the electrical devices and safety of the people using them.

Like all other distribution systems also the LVDC system needs to be grounded. The two safest solutions for grounding are the IT-grounding system and the TN-grounding system (LUT 2007). Usually in distribution systems 20 kV medium voltage network is isolated from the ground using the IT-system or grounding through impedance. The other possibility in 20 kV networks is the extinction of earth fault current by compensation where the transformer's star point is connected to the ground through a coil. The purpose of the coils is to compensate the capacitive earth fault current.

The LVAC system is often operationally grounded TN-system. When IT- and TN-systems are connected through the distribution transformer, the transformer's star point is not grounded. If it were, two systems would turn an earth fault into a short circuit fault through the ground. The building installations are operationally grounded and it is galvanic separated from the distribution network. (Rekola 2009) The principals of the grounding systems are shown in Figure 2.7.

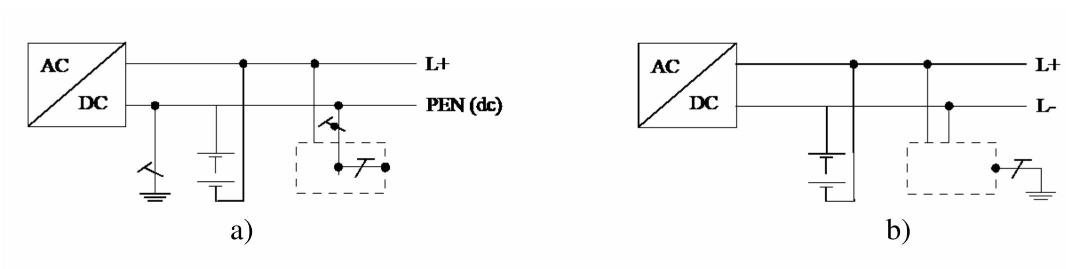

Figure 2.7. *The grounding system principles for the unipolar DC system using a) TN-C grounding and b) IT grounding (LUT 2007).*

In the IT-system, the transformer's grounding is not a problem in the normal state, but when there is an earth fault in the DC system it forms a short circuit fault through the ground. In both TN and IT systems the short circuit fault corresponds to an one-phase earth fault in the AC system. The fault is symmetrical in both poles then the state does not depend on which of the DC systems poles are grounded and in where the earth fault is. In Figure 2.8 there are the faults that result from the transformers star points grounding. (LUT 2007)

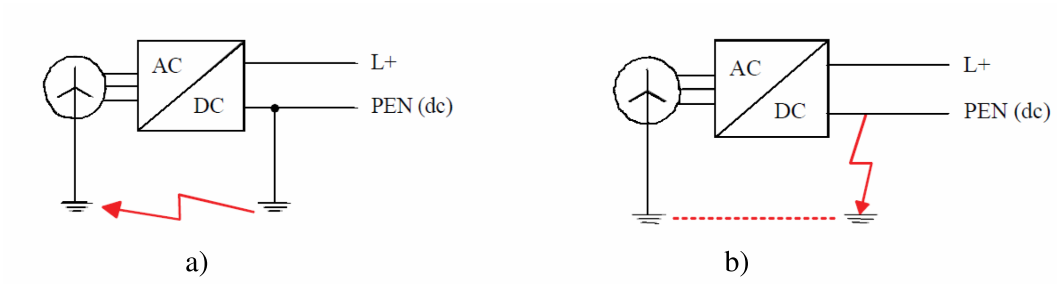

Figure 2.8. *The fault situations resulted from the transformers grounding when using a) TN grounding and b) IT grounding (LUT 2007, p. 23).*

The building installations of the customers must be galvanicly isolated from the distribution network so the operational grounding system will be safe (LUT 2008). If there were not the galvanic isolation, the earth faults in the distribution network together with the operational grounding of building installations would form a dangerous double short circuit fault through the ground (LUT 2008).

As this master's thesis focuses on the point of view of an electricity distribution company, there will not be any deeper study about the protection of the building installations of the customer. As the electricity distribution companies have no permission to oblige their customers how they should build the protection of their building installations, they just need to follow the instructions given by the standards and law. In practise this means that the galvanic isolation needs to be guaranteed and the grounding needs to be safe enough. With LVDC-systems, this means that the converters need to be somewhat oversized so it is able to feed enough fault current to the customers' building installations and the galvanic isolation transformer needs to be placed between the customer and the LVDC-system. When these two things have been taken care of the existing protection systems of the customers' building installations will work the way it should. In a way, this also makes the technology implementation easier, because then there is no need to change anything in the customers' protection and no extra supervision for the customer's building installations modification is necessary and there isn't any need to think about who is responsible for the modification supervision. On the other hand there is the over sizing problem which increases the costs of the converters. (Lähdeaho 2011)

2.8 Possible converter topologies

The rectification can be done by several ways. The power electronic components can be diodes, thyristors or active switches like IGBTs. The simplest solutions for rectification are to use 12-pulse diode or thyristor rectifiers. More complicated and more adjustment options to offer rectifiers are the Vienna-rectifier. The Vienna-rectifier enables modification to the feeding networks current power factor but they do not allow power transfer both ways. The power flow is always from the medium voltage network to the low voltage network. The most typical rectifier topologies are described later in this chapter. (LUT 2010)

Like rectifier topologies, there are also several different inverter topologies as well. In LVDC distribution it is important to use active switches, so the AC voltage produced by the inverters will fill all the limits set by the standards. (Rekola 2009) With IGBT-inverters it is possible to transfer power in both directions which enables distributed generation (DG) connected to the LVDC network and its large scale utilization. If there is enough DG connected to the LVDC network, it is possible to use it as an island grid in case of an interruption in the MV distribution network. The DC voltage level can be kept in a certain value with the actively adapting inverters. The most typical inverter topologies are described later in this chapter. (LUT 2010)

2.8.1 Rectifiers

Rectifiers can be one or three phased and two- or three-level. The 6-pulse diode rectifier topology is the most used one, simple and inexpensive. Other options are the 12-pulse half-controlled thyristor rectifier where half of the diode rectifier's diodes have been replaced with thyristors. Three other rectifier types are built with active IGBT- components. (Rekola 2009)

The simplest and inexpensive rectifier is shown in Figure 2.9. It is a 6-pulse three-phased diode rectifier. Like according to its name it consists of six diodes. It is most commonly used in different industrial devices. With diodes it is easy to make a rectifier bridge that stands quite high voltages and currents. The advances of diodes are their simplicity and high efficiency. On the other hand diodes are not controllable components so the DC-voltage depends entirely on the feeding systems voltages amplitude. This is why the average DC-voltage can be set only by placing a transformer before the rectification bridge or when the voltage of the preceding network is the desired one. This phenomenon leads to a situation where the voltage dips from medium voltage network are conducted to the LVDC system and from there to the customer. Voltage and current produced by the diode rectifier are not completely pure DC voltage due to the diodes alternating conduction. As a result of this, forms to the DC voltage 300 Hz frequency ripple. One of this rectifier's disadvantages is the large amount of low frequency harmonics it creates into the network. The largest harmonic components are the 5th, 7th, 11th and the 13th. (Rekola 2009)

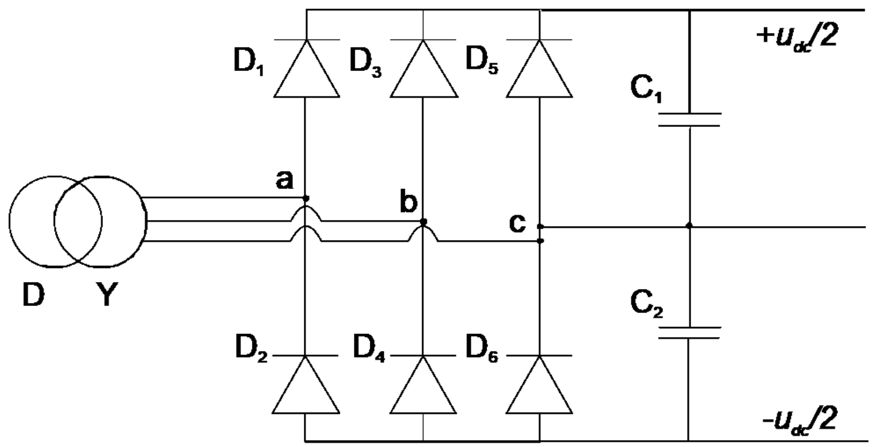

Figure 2.9. *A model of three-phase 6-pulse diode rectifier topology (Rekola 2009).*

When implementing the bipolar system with the 6-pulse diode rectifier, it forms a challenge keeping the voltage balance between the two capacitors. This problem can be solved by connecting two 6-pulse rectifier-bridges in cascade. It is the same as the twelve-pulse rectifier-bridge. The rectifier in Figure 2.10 is called half-controlled because half of its components are thyristors and the other half are diodes. The 12-pulse rectifier needs to be fed by a special transformer which has two secondary windings one connected in delta and the other in star shown in Figure 2.10. The phase difference between the two secondary sides needs to be 30°. More about different rectifier topologies can be read from Mohan's Power Electronics, Converters, Applications and Design.

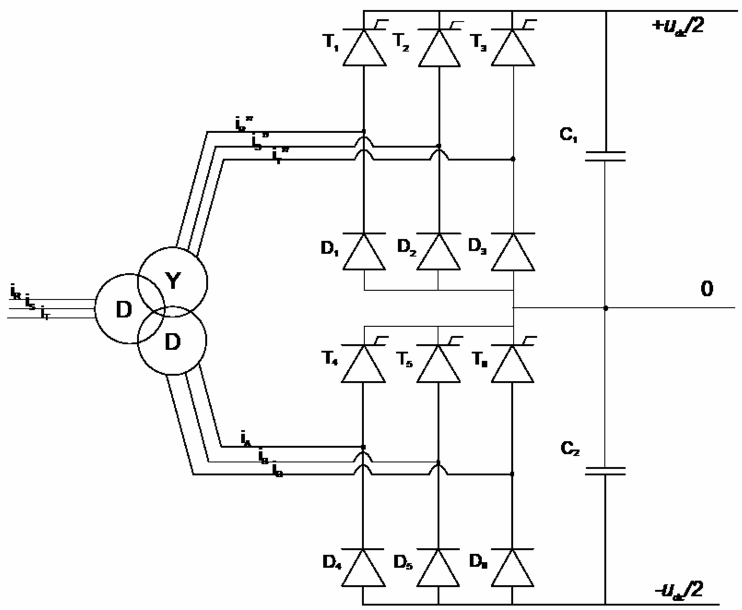

Figure 2.10. *A model of three-phase 12-pulse half-controlled thyristor rectifier (Rekola 2009).*

In addition to the rectifiers presented above, there are also two-level rectifiers which have zero conductors. The zero-conductor is connected from the "feeding" transformers' star point to the middle point of the rectifiers' intermediate circuit. This kind of rectifier structure is presented in Figure 2.11.

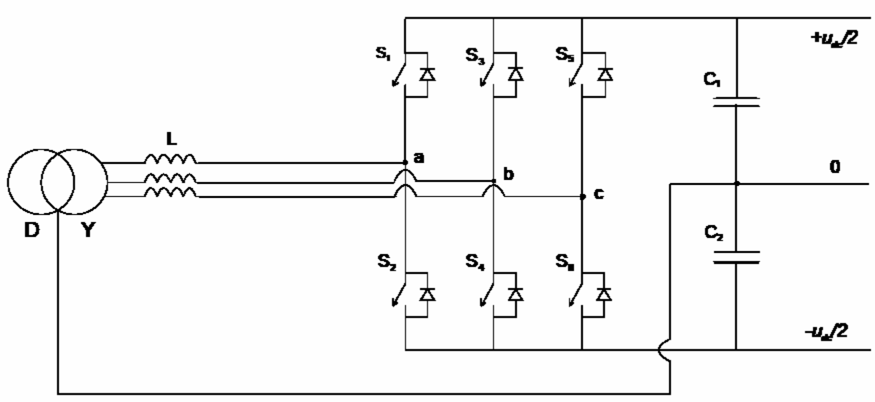

Figure 2.11. *A model of two-level three-phase zero-conductor rectifier (Rekola 2009).*

In Figure 2.11, the coils L are the network filters and the capacitors C1 and C2 smooth the voltage of the DC intermediate circuit.

One of the new directions of research in power electronic converters are the three-level converters though the operating principals of the three-level NCP-inverters were introduced already in 1981. The name NCP inverter stands for neutral point clamped-inverter. In practice the three-level means that there are three voltage levels used in the rectifier. In Figure 2.12 is a model of one-phase of a three-level NCP-inverter. It consists of four active switches S(1-4) and two locking-diodes D(1-2). The zero voltage level in the inverter is formed by dividing the voltage of the intermediate circuit into two parts by capacitors C(1-2). (Rekola 2009)

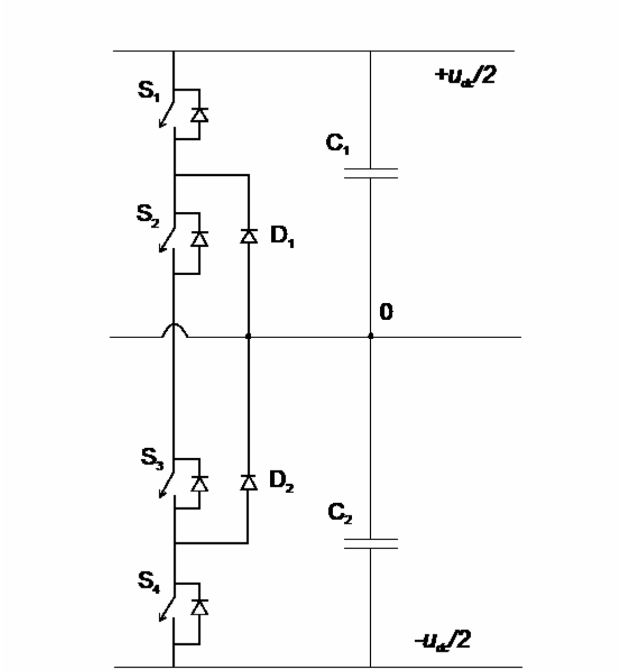

Figure 2.12. *Model of one phase of a three-level NCP-rectifier (Rekola 2009).*

In past few years, when active switches have developed and the prizes have decreased, the three-level rectifiers have become true rivals to the two-level rectifiers. The bridge structure of the three-level rectifier is more complicated then in the two-level because it has more switch components. (Rodriguez & al. 2002) The three-level rectifiers are mostly used in medium and high voltage applications in 100 kW – 10 kW power ranges, where the reverse overvoltage limits of the two-level rectifiers are not big enough. In the three-level rectifiers it is only half of the intermediate circuit voltage over the switch components. Due to this it is possible to choose half smaller switches which have lower tolerance to reverse over voltages than the corresponding two-level rectifiers. The switch components with smaller ability stand for reverse over voltages have smaller switching losses and smaller voltage stresses.

2.8.2 Inverters

Like rectifiers inverters can be build one- or three-phase and as two- or three-level. When using inverters in distribution networks they need to be build from active switch components so the power quality limits set by the standards can be filled. IGBT-components' withstand of voltage is enough in low voltage distribution systems. With

IGBT, the switching frequency is high 1-20 kHz. This leads to high-frequency harmonic distortion and then only small load filters are considered necessary. When the inverter is actively “guided”, it does not matter what kind is the DC voltages plot. With the active control small voltage drops and high-speed autoreclosures can be eliminated from the customers’ installations.

The two-level inverter can be either one-phase half- or completely-controlled, or three-phase. The inverter is connected to the DC intermediate circuit voltage or to a half of the voltage in the DC intermediate circuit. In Figure 2.13 is a model of two one-phase half-bridge inverter’s structures.

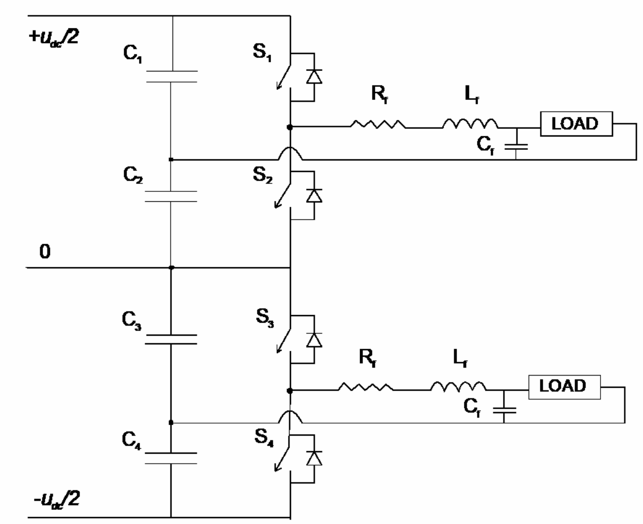

Figure 2.13. *Two one-phase half-bridges connected to $U_{dc}/2$. (Rekola 2009).*

With a half-bridge inverter there are only two possible switching options. A simple two-level half-bridge inverter needs large capacitors.

2.8.3 Summary of the converter topologies

The biggest difference between IGBT and thyristor or diode converters is the bidirectional load flow, which is possible only with the IGBT converters. The lifetime and reliability of three converter component options are discussed later in this study in Chapter 4.

Among the bidirectional load flow the IGBT converters are also able to act as voltage boosters. For example if the voltage in the main line would drop due to a short circuit fault on the next MV feeder the customers after the IGBT converters would not suffer any voltage drop at their connection point. And when using commercial IGBT-converters they can act as both inverters and as rectifiers, this decreases the number of different network components needed in storage.

3 INTRODUCTION OF THE LVDC TEST SYSTEMS

Below there is a brief review of the test system installed in LNI’s distribution network and the description of the becoming test system that is planned to be installed in the summer of 2012 and a brief review of a LVDC test system implemented by LUT and Suur-Savon sähko Ltd. In the first chapter there are also some test results and experiences of the test systems functioning as a part of the distribution network. The first chapter also includes the challenges, successes and a brief analysis of the whole test system.

The idea of LVDC test system started from LNI’s strategic decision of using only underground cables whenever soil circumstances allow it. As a result of the decision LNI started to search alternative ways to rebuild 20 kV branch lines especially in the rural areas. In the rural areas, cost efficiency is a challenge because 20 kV branches are usually lightly loaded.

3.1 The current test system

ABB Drives was selected as copartner for the test system manufacturer. The co-operation began with meetings where LNI explained what their aims towards this test system were and after the mutual understanding the actual project was launched in the early 2008

At first there were some challenges utilizing the inverters as a part of the distribution network. Usually, the inverters are used in sensitive industrial processes where keeping the current as stable as possible has been the most important task of the inverter. When, implementing inverters into the distribution network of electricity the main task is to keep the voltage at the same level all the time. This difference created a need to change the inverters' software. (Lähdeaho 2011)

3.1.1 Schedule

The current test systems planning started in autumn and winter 2008. The first things to do were finding an appropriate test location and defining the operational and technical features. The early winter of 2009 went in finding the right components and discovering their usability in this test system. The early spring of the same year there was some measuring done in the test location, for example maximum load and voltage characteristics. It took the whole spring and a little bit longer to re-programme the inverters to stabilize the voltage instead of the current. In June 2009 ABB presented their first proposal of the test system and the final test system was introduced in August. The test system was built and tested during the fall 2009. The following tests were done to the system (ABB drives 2009):

- Temperature rise
- The ability to feed short circuit current
- Short circuit tolerance
- Contactors switch over
- Battery test
- Power quality
- Overload current limitation
- Start logic
- Cabinet heater
- Remote control

All the tests were done by ABB drives and the tests were made in their test laboratory. After the testing, the power quality tests at the site were done in the test location in northern Pirkanmaa during December 2009 and January 2010 and the actual implementation and construction took place in the spring 2010. (Komsi 2011b)

3.1.2 Structure

The basic structure of the test system is shown in the following figure 3.1. The customers are fed through back-to-back 120 kVA IGBT converters with LCL (inductor-capacitor-inductor) filters. The converter placed on the supply side makes the rectification and the converter placed on the customer side generates constant AC voltage and frequency for the customers from the common dc link. (Niiranen & al. 2010) There are two transformers on both sides of the converters as can be seen from Figure 3.1. The purpose of the transformer before the rectifier is to boost the voltage from the distribution transformer so the rectifier can produce 500 V DC-voltage. The transformer also prevents the possible transmission of common mode interference to the low voltage network. The purpose of the other transformer is to provide a neutral point to the customer side of the grid and galvanic isolation between the DC bus and the customer network.

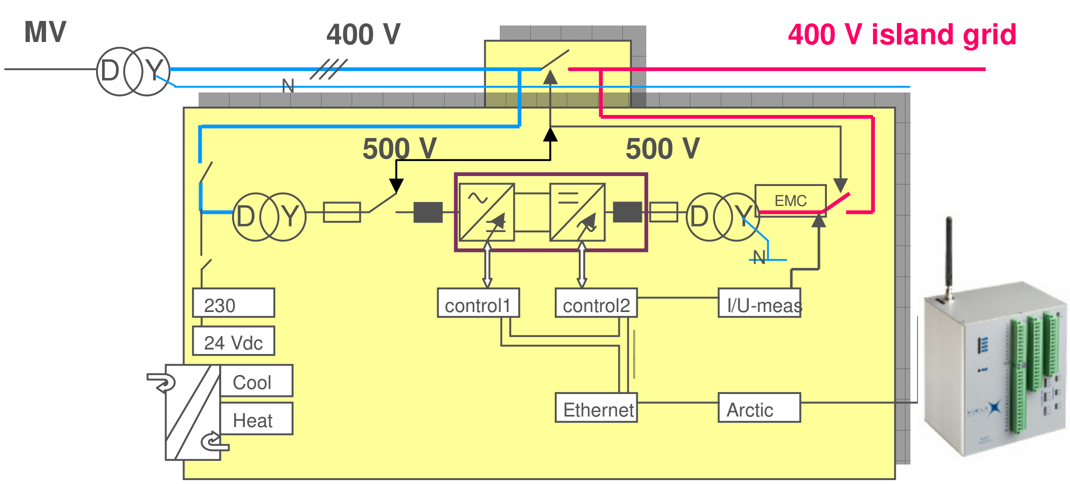

Figure 3.1. *Single-line diagram of the converter cabinet and test site (Komsi 2011a).*

Like shown in Figure 3.1 there is a possibility to bypass the converters for maintenance or in fault situations i.e. the arrow in the figure. The converters can be monitored and controlled remotely via wireless GPRS communication system by LNI's SCADA system. There is a back-up battery system for the communication systems for the black-out cases. The whole equipment with transformers is installed in a hermetically enclosed IP65 outdoor cabinet shown in Figure 3.2. (Niiranen & al. 2010)

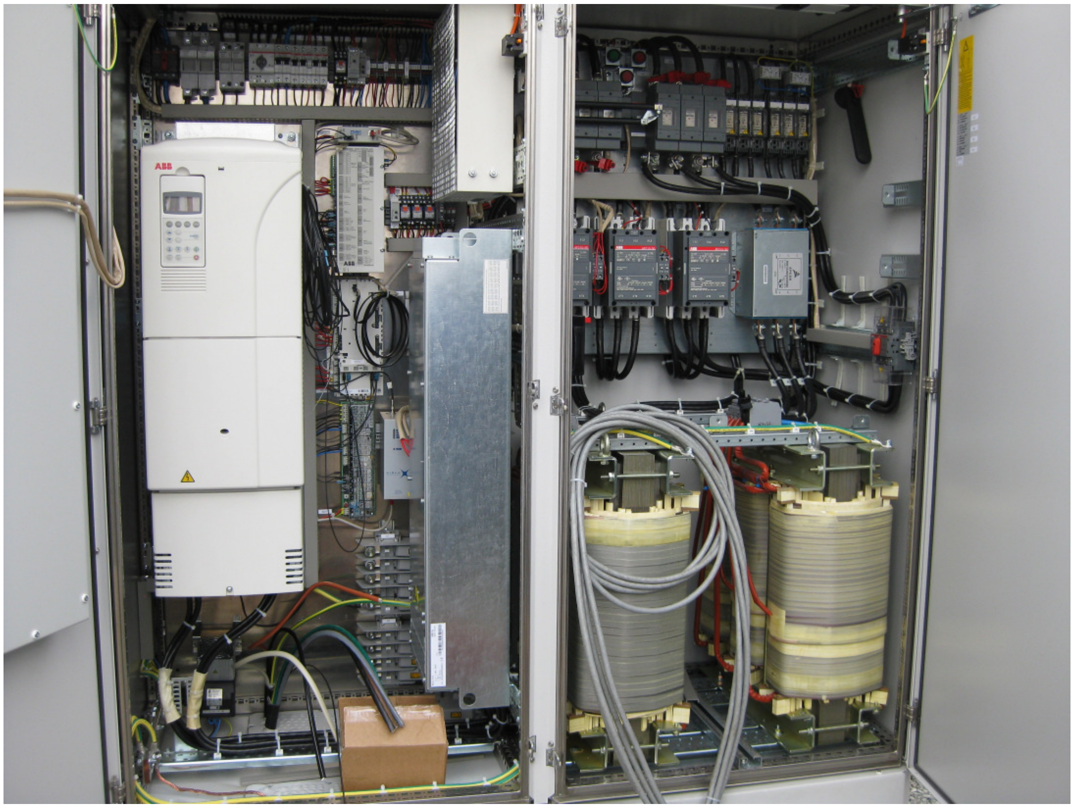

Figure 3.2. *Inside of the converter cabinet. ACS800-11-5 back-to-back converter module is shown on the left.*

In Figure 3.3 is the test location of the pilot system on a map base. As from Figure 3.3 can be seen the customers fed by the converter are located on a peninsula and the distance to the MV/LV transformer is about 1 km of which 300 m is underwater cable.

Figure 3.3. *The location of the test pilot on a map base. The location is encircled.*

3.1.3 Experiences on power quality

Now the pilot system has been on set up for almost two years. LNI and ABB have collected user data and customer experiences of it. The loads of the converters consist of mainly one-phase household equipment. The highest loads were mainly resistive because it consisted of electrical heating devises. Before the LVDC test system was implemented there were some complaints from the customers about flickering and there were also some problems in voltage fluctuations.

In distribution networks power quality in practise means the quality of the voltage. The quality of voltages consists of the following features frequency, the extent of voltage, quick changes in voltage which cause for example flickering, waveform, and symmetry of phase-voltages, interruptions and disturbances of a different kind. Standards have set the limits for the distribution voltage. These limits were presented in this study earlier in Table 1.1. According to Electricity Market Act the delivery of electricity is faulty if it does not come up to the standards or it is continuously or frequently interrupted and the reasons cannot be considered concise when considering the reason for the interruption and the circumstances.

Besides the standard SFS-EN 50160 there is a publication from Sener ry that deals with the evaluation of the power quality: ‘Evaluation of power quality in distribution networks’. In this publication there are recommendations to the essential quality factors and in practise the possible power quality measure and evaluation criteria. The quality criteria number values that concern low voltage network are presented in Table 3.1.

Table 3.1. *Evaluation criteria of power quality in low voltage networks. (Mäkinen 2010)*

Voltages feature	High quality	Normal quality	Standards filling quality	Notifications
Frequency	50 Hz ± 0,5%	50 Hz ± 1%	99,5 % of year: 50 Hz ± 1% 100% of time: 50 Hz +4% / -6%	measuring in 10 s periods
Fluctuation of voltage	220 - 240 V and avg. 225 - 235 V	207 - 244 V	95 % of time: U_n = ±10 % all the time: U_n = +10 % / -15%	Measuring in rms-values 10 min averages
Flickering severity index	$P_{st,3max} \leq 1$ $P_{lt,max} \leq 0,8$	$P_{lt,max} \leq 1$	95 % of $P_{lt} \leq 1$	
Harmonic distortion	THD ≤ 3%	Uh ≤ values in Table 1.2 THD ≤ 6%	95 % of time: Uh ≤ values in Table 1.2 THD ≤ 8%	Measuring in 10 min periods during a week
Asymmetry	$U_{uSh} \leq 1\%$	$U_{uSh} \leq 1,5$ %	95 % of the time: $U_{uSh} \leq 2\%$	Measuring in 10 min periods during a week

The standard SFS-EN 50160 also specifies how the features should be measured. According to it, the voltage fluctuation, harmonic over voltages and asymmetry of voltages must be measured as 10 minutes averages, frequency as 10 second average, the signal voltages in 3 second averages and the flickering severity index P_{lt}-values as 2 hour values. The values mentioned before are often specified still a bit more like: The measured averages must be in the framework of the limits at least 95 % of time during a week.

After the implementation, the power quality was improved and it can be seen from figures 3.4 and 3.5. In Figure 3.4 there are customer's phase voltages when the converters are in bypass mode and in Figure 3.5, the same phase voltages when the converters are connected to the network. From Figures 3.4 and 3.5 can be seen that, the converters are able to keep the voltage fluctuation very low when compared with the bypass mode. If these measured values are compared with the evaluation criteria values in Table 3.1, it shows that when the converters are connected the voltage quality is high and when they are in bypass mode the quality of voltage is barely standards filling during the measuring time.

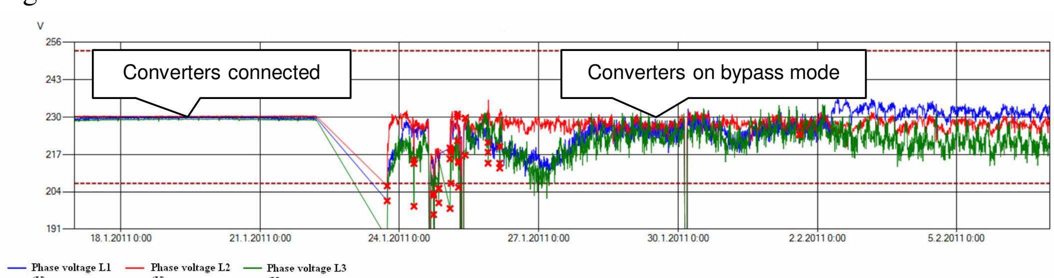

Figure 3.4. *Phase voltages L1, L2 and L3 of the customer when converters on by pass mode.*

The phase voltages L1, L2 and L3 in Figure 3.4 were measured during the weeks 3-5 2011. As from the figure can be seen the converters moved to the bypass mode at the 24.1.2011 and it was due to the series of autoreclosures. The change from ON mode to the by-pass mode as a result of autoreclosures was resulted by a small fuse on the 24 V control circuit that had burned. This lead to a minor change: The control of the bypass contactor is now coming from the supply grid (230 V). This ensures that the bypass is properly controlled if the cabinet 24V trips. (Komsi 2011b)

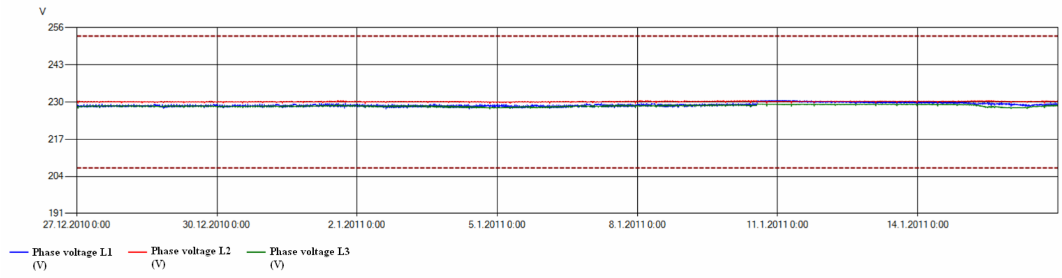

Figure 3.5. *Phase voltages L1, L2 and L3 of one of the customers when converters connected in the network.*

Frequency of the distribution network is also an important factor when evaluating the quality of supply. In the following Figure 3.6 is the frequency of the customers supply from the weeks 3-5 of the year 2011.

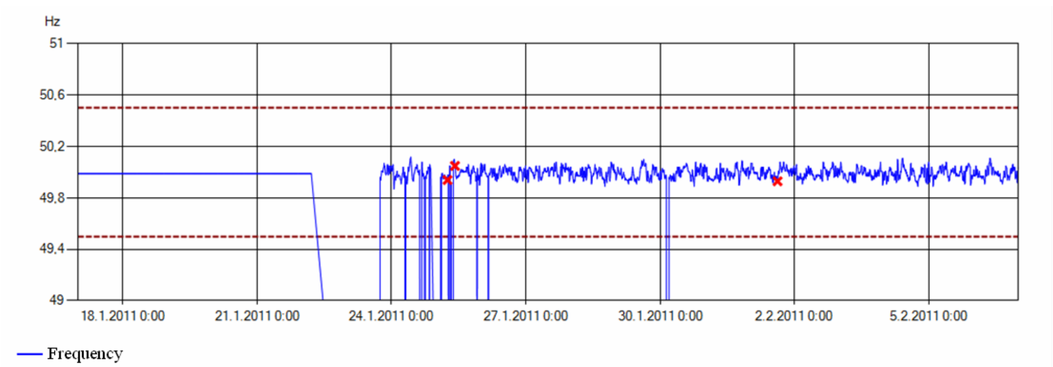

Figure 3.6. *The frequency of the customers supply.*

The converters are able to keep the frequency exactly at 50 Hz as from Figure 3.6 can be seen. On the other, hand the fluctuation of frequency when the converters are in the by-pass is also standards filling. Compared with the evaluation criteria both converters connected and converters on the by-pass mode fill the limits of high quality in the behalf of frequency.

Flickering was one of the reasons when this place was selected as a test site for the converters. In the following Figure 3.7 is the Plt index measured during the weeks 3-5 in 2011.

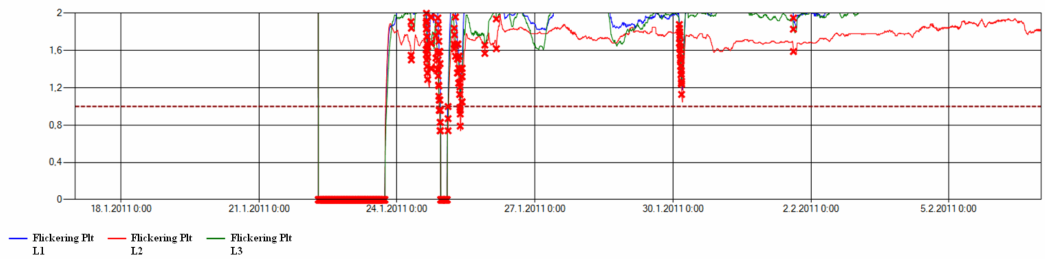

Figure 3.7. *Flickering index P_{lt} of phases L1, L2 and L3 of the customer.*

From Figure 3.7 can be seen that the Plt index is 0 during the time the converters are connected. When, the converters switched to the bypass mode on the 24.1.2011 the long term flickering severity index rises to a value of 2. According to standard SFS-50160, the Plt should be less than 1 95 % of a weeks measuring time. When, the converters are connected the flickering severity index is the best possible one and is high quality when comparing with the evaluation criteria in Table 3.1, and when they are in bypass mode the quality is dramatically decreased and does not even fill the limits of the standard.

As a minor harmful aspect of using converters in distribution networks is the increase the total harmonic distortion THD. From the following Figure 3.8 can be seen that as the converters are connected the THD stays quite steadily at 5,4 % which is just inside the limit of normal quality when compared with the evaluation criteria in Table 3.1.

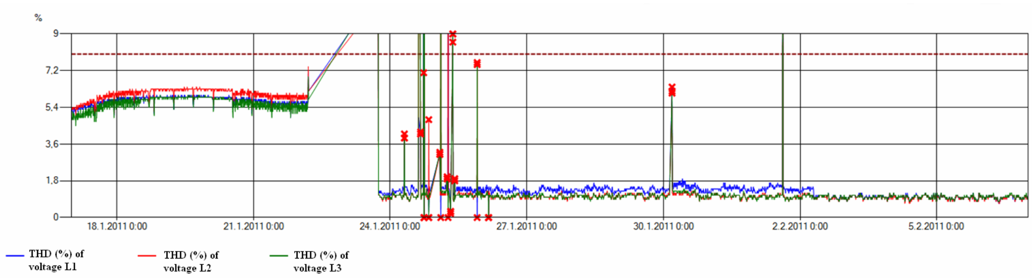

Figure 3.8. *Total harmonic distortion in phases L1, L2 and L3 of the customer.*

As Figure 3.8 points out the THD is much smaller, less than 2% when the converters are in by-pass mode. When, comparing this with the evaluation criteria it means high quality. The THD measuring is also from the weeks 3-5 of the year 2011.

All of the figures above which represent the measuring results comes from a customers AMR meter. During the implementation of the test system one of the customers were equipped with an AMR meter for the web surveillance of the power quality.

3.1.4 Other experiences

Although the power quality improved due to the converters, the cabinet's cooling system created some audible noise complaints from one customer. The noise problems are due to the cabinet's cooling fan. Because of the audible noise complaints, the converter has been on by-pass since June on the other hand, all this time there have been complaints about flickering.

The main purpose of this test pilot was to test the power electronics converters in distribution application. During the time, the test pilot has been running there has not been any problem with the actual converters. The only challenges were with the fuses of the by passing system. The other challenge was to handle the noise from the cabinets' cooling fan. One other thing that needs to be taken into notice in the upcoming test system is the placing of the cabinets. It should be placed at some distance from the nearest dwellings, so the noise would not be disturbing the customers.

3.2 The upcoming test system

After getting good experiences from the first test system, LNI and ABB decided to continue their co-operation for another larger LVDC distribution test system. Like the first test system, this one's purpose is also to test the equipment and gain experiences about the quality of supply and the reliability effects.

The tentative schedule of the test system is introduced first. After it is an introduction of the intended structure. Basically the structure is the same as in the present system, but the biggest difference is that this time there will be a 800-meter DC cable.

3.2.1 Schedule

The project of designing and building the new test system started in the summer 2011. The first thing done was determining the technical regulations for the system:

- How long cable is possible?
- How much power could be transmitted?
- Structure bi- or unipolar?
- Centralized or consumer specific inverting
- What kind of cable to use?
- How many consumers in the area?

The search of the actual test location started after the things mentioned above were determined. During the search came up quite a few good places where to apply the LVDC distribution system. When searching a suitable test site, came up the idea of replacing very long LV lines where the consumer is near another 20 kV main line. In this context, a very long LV line means lines over 900 m long.

3.2.2 Structure

The basic structure of the future test system is shown in Figure 3.9. First on the left side is 20 kV main line (1), after it is the usual distribution transformer (2), then the rectifier (3), the DC cable (4), the inverter (5), the galvanic isolation transformer (6), EMC filter (7) and the load (8).

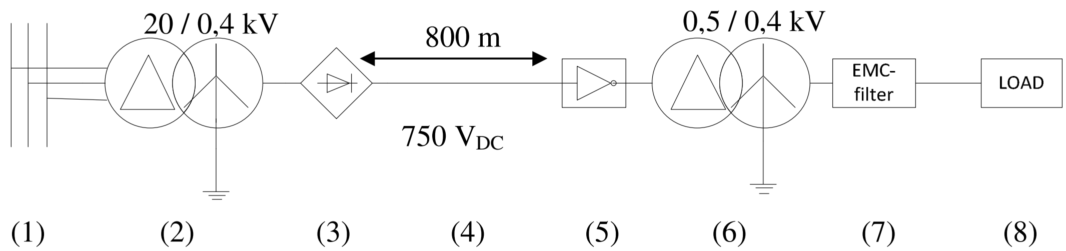

Figure 3.9. *The intended principle structure of the upcoming test system.*

In this test system, the load consists of two summer cottages and one household. The total maximum power consumption is 13 kW and the annual average energy consumption is 17 MWh.

3.3 Test system of LUT and Suur-Savon Sähko Ltd.

Like LNI other network companies with large parts of their network located in rural areas have been interested in LVDC distribution system research as well. One of these companies is Suur-Savon Sähkö which in co-operation with the Lappeenranta University of Technology has built and started testing the following LVDC system. In Figure 3.7 is a model of the test system.

They started planning the test system at the beginning of 2010 and the general plans were ready in April of the same year. The test site was then selected and the assembly of the converters started in November 2010 with the rectifying substation. The designing work of all components was ready in December of 2010 and in March 2011 started the assembly of the inverting substations. The purpose was to have the on-site installations done in May 2011 and the integration with the remote supervision and management systems of Suur-Savon sähko Ltd done in June 2011. Also the energising and the test measurements were supposed to done in June 2011 so the first follow-up period could start in July 2011. (Kaipia 2011)

As from Figure 3.7 can be seen there are three inverters feeding four customers. The length of the DC cable is approximately 1,7 km and in the same ditch with it is the same amount of optical fibre. There is also a few hundred meters of low voltage AC cables. The energy consumption of the customers is approximately 25 MWh/a and the peak demand is 24 kW. The galvanic isolation transformer is missing from this principal structure figure 3.10. The transformer is placed between the inverter and the customer and its purpose is to create the galvanic isolation between the LVDC network and the customer. It also prevents the conduction of common mode disturbances from the LVDC network to the customer and the other way around, and the possibility of DC voltages conduction to the customers building installations

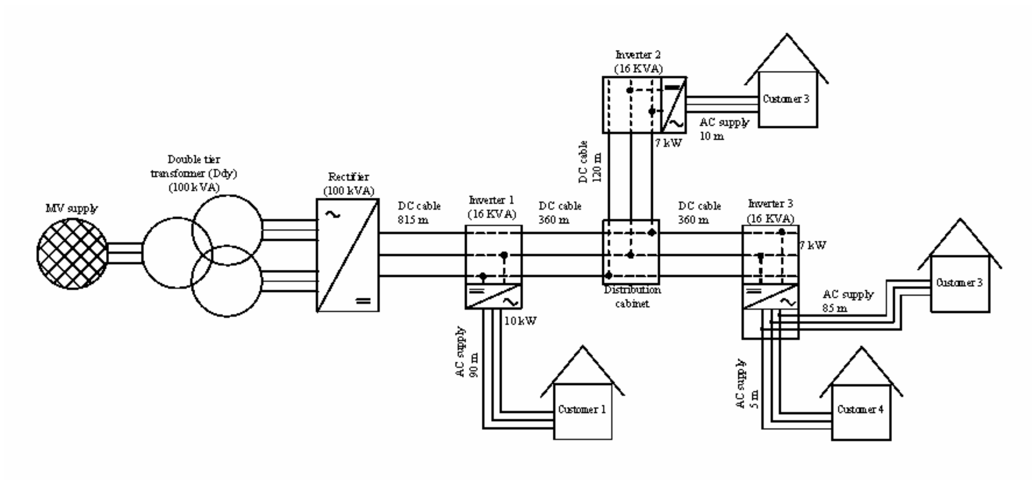

Figure 3.10. *The principal structure of the LVDC test system of LUT and Suur-Savon Sähkö Ltd (Kaipia 2011).*

The test system is built as bipolar and the more specific diagram of the rectifying substation is presented in Figure 3.11. The DC voltage levels used in the system are +700 V and −700 V and there is a common zero for both phase conductors. The rectifiers are fed by a special transformer which has two secondary windings one connected in delta and the other in star this can be seen from Figure 3.11.

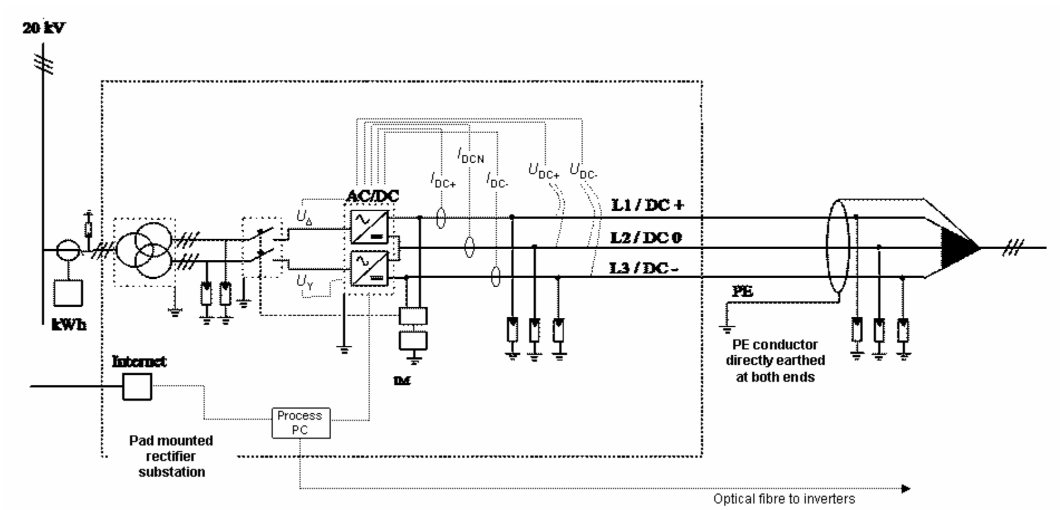

Figure 3.11. *Detailed view of the rectifying substation (Kaipia 2011).*

In Figure 3.12 is shown, in more detailed the inverting substations of the test system. There is a filter after the rectifier and a transformer which is grounded from its secondary side's star point to gain the galvanic isolation between the DC bus and the customer's installations. The optical fibre operates as a communication channel between the rectifier and the inverters. Thorough it is transferred all the data that the converters need from each other.

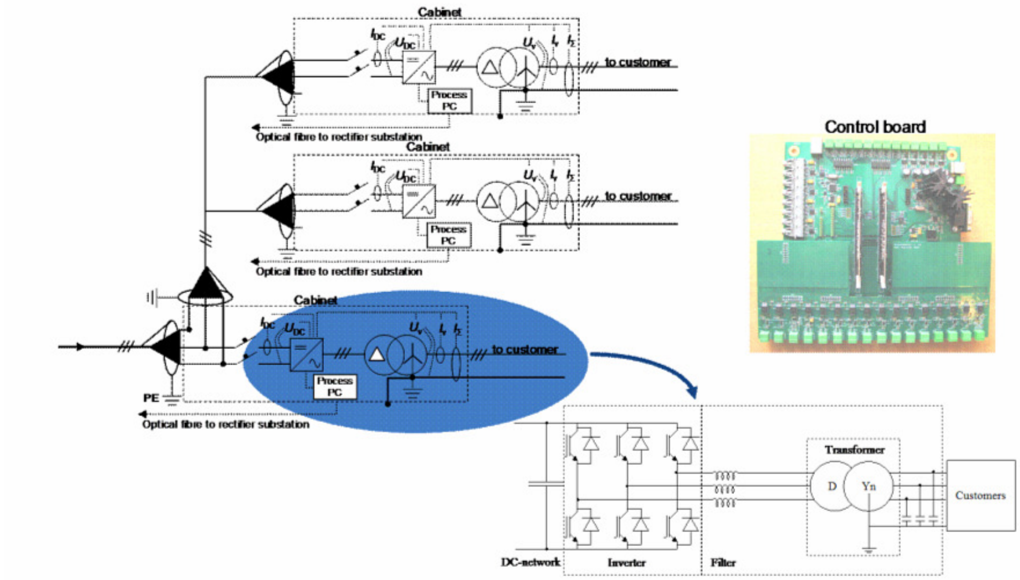

Figure 3.12. *Detailed view of the inverting substation (Kaipia 2011).*

In this test system, only the inverters IGBT transistors are oversized, so they would be able to feed the required amount of fault current to the customers' fuses to satisfy the 0,4 s rule.

3.4 Finnish LVDC system compared to others

In Finland, the research of LVDC systems has started from the network side. Elsewhere in Europe where the distributed generation is the upcoming form of energy production they have started the development of LVDC systems from that point of view. So when in Finland the study of LVDC systems is concentrating on how to apply it in the distribution networks. In Europe it is about how to connect the DG, especially PV (photo voltaic) systems, to the network without the losses of inverters and the solution is to build a LVDC networks to office buildings and dwellings. The other "big" thing is the electrical vehicle and its loading. (Marquet & al. 2011)

4 RELIABILITY OF THE DISTRIBUTION NETWORK

The following reliability examinations are done to an average substation medium voltage feeder which is selected using definitions presented in the Bachelor's thesis of Tomi Hakala (Hakala 2011). In the Bachelor's thesis is determined the usability potential of LVDC system in LNI's network area. The data of MV feeders from Hakala's thesis are used also in the cost calculations in the following chapter.

The average number of replaceable branch lines in a MV feeder is calculated from the data which contains all the possible replaceable branch lines which full fill the conditions set in the Tomi Hakala's Bachelor's thesis. From the same data is also calculated the average line length replaceable by the LVDC cable per one MV feeder. The whole network of LNI Verkko has 8266 branch lines which are longer than 100 m. An average length of one branch line is 580 m. (Hakala 2012) In the distribution network of LNI verkko there is 736 MV feeders and the total number of customers is 409042 and the total energy consumed is 1,3 GW The average MV feeder of LNI verkko has 556 customers and average energy consumed on the MV feeders is 1,79 MW.

To this study, the average MV feeder is selected among a list of replaceable branch lines which are calculated with 10% voltage drop in the DC cable when the cable is AX 95. The AX 95 is a commonly used cable in LVAC networks where the 95 means cross section area of the cable. With these terms from the whole network of LNI could be found 8002 branch lines which are replaceable with LVDC. These branches are located on 597 different MV feeders and the total length of the replaceable network is 4642 km. This means that an average MV feeder has 13 replaceable branch lines when rounded to the nearest integer number. The length of the replaceable network on an average MV feeder is 7,78 km when rounding to the nearest hundredth.

When, searching for the MV feeder which has 13 replaceable branch lines there were thirteen options. The MV feeder named 11 KST_KIVIJÄRVI was chosen to target of inspection. The names of the MV feeders follow a certain pattern, the number in the beginning is the number of the MV feeder from the substation, the first three letters are the abbreviation of the name of the substation, and last part is usually the name of the feeding area. The reasons that lead to this decision were the average ages of the replaceable branch lines and the fact that on this MV feeder they were the oldest. The other factor that also affected on the decision was the length of the replaceable lines 7,6 km which is very close to the average length of the replaceable branch lines on one MV feeder. The topology of 11 KST_KIVIJÄRVI MV-feeder is presented in Figure 4.1 with yellow colour. The replaceable branch lines are circled with pink in Figure 4.1.

The MV feeder in question consists of 18,3 km of overhead lines, 4,2 km of underground cable and 1,3 km of insulated over headlines the total length of the MV feeder is 23,8 km. The number of customers on the MV feeder is 218. The number of the customers on the replaceable branch lines is 142. The power fed by the MV feeder is 495 kW and the annual energy consumed on this MV feeder is 1747 MWh.

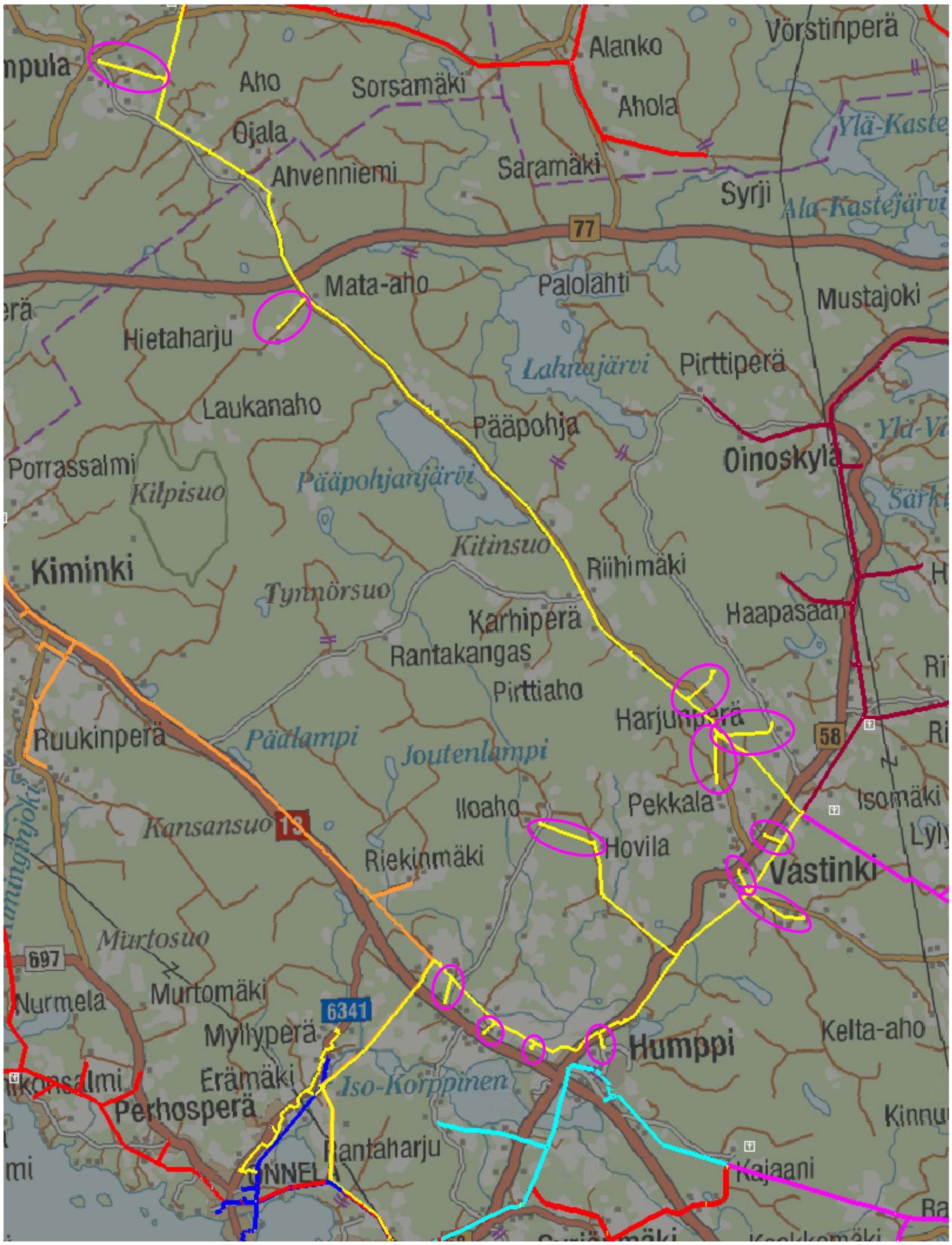

Figure 4.1. *The MV feeder 11 KST_KIVIJÄRVI (yellow) with the average length of replaceable branch lines circled with pink.*

In the following Figure 4.2 is the MV feeder which had the closest length 7,7 km of replaceable branch lines to the calculated average length of the replaceable branch lines in one MV feeder. The MV feeder selected for inspection is coloured red in Figure 4.2 on the next page. The replaceable branch lines are circled with blue in Figure 4.2. The name of the MV feeder is 03 LSJ_MIEKKO. The power fed by the MV feeder is 720 kW and the annual energy consumed on this MV feeder is 2926 MWh.

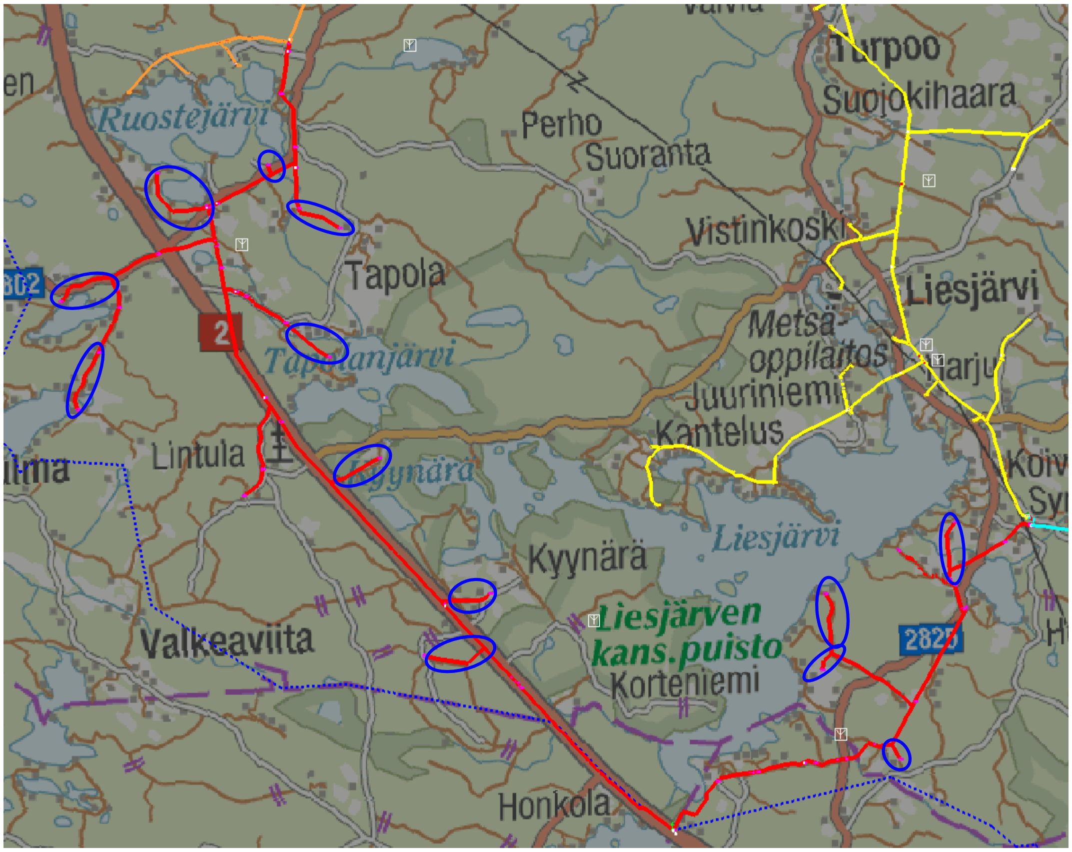

Figure 4.2. The MV feeder 03 LSJ_MIEKKO (red) with the average length of replaceable branch lines circled with blue.

The MV feeder in question consists of 33,8 km of overhead lines, 1,1 km of underground cable and 0,1 km of insulated over headlines and the total length of the MV feeder is 35 km. The number of customers on the MV feeder is 332. The number of the customers on the replaceable branch lines is 197.

4.1 Definition of reliability in distribution network

Reliability is another important factor besides power quality in distribution networks. The main factors in defining the reliability of supply are the frequency of interruptions, the duration of each interruption and the value a customer places in the supply of electricity at the time that the service is not provided. These factors depend on variables of a different kind such as the reliability of the individual components of equipment, line length and loading, the network configuration, distribution automation, load profile and available transfer capacity. In the standard SFS-EN 50160:2010 an interruption is defined as a situation where voltage in the customer's interface is less than 5 % of the nominal value Un or from the agreed distribution voltage Uc. Interruptions in distribution networks are divided into short and long interruptions. They are defined that a long interruption is over three minutes and a short interruptions maximum time is three minutes.

When, defining reliability there are few important terms that need to be defined. They are listed in this paragraph: Dependability means the object's in examination ability to complete the required function at the required time or the required period of time in certain circumstances. In this case, the object can be a distribution network or one of its components. A fault means that a component is in a state in which it can not perform the function required from it. The intention is that the faults which are important from the safety or the reliability point of view set off protection functions. Usually, the circuit breaker controlled by a relay makes the MV feeder dead. Switching delay is the time that is needed to isolate the faulted component from the network. Repair duration is the time that it takes from the starting of the fault to the moment when the voltage to the component is restored. Fault frequency indicates how many faults in a component occur in a certain time period. (Lakervi 2009; Lakervi 1995)

In Electricity Market Act is also defined constant amends to the customers in case of long interruptions in distribution. The constant amends are always determined from the annual network service charge of the customer in the following range:

10 % when the interruption time has been at least 12 h but less than 24 h;
25 % when the interruption time has been at least 24 h but less than 72 h;
50 % when the interruption time has been at least 72 h but less than 120 h;
100 % when the interruption time has been at least 120 h.

The maximum constant amend of interruption in distribution is 700 € per one customer. The hindrance of the customers experience in the interruption is discussed more detailed in the next chapter.

Besides the interruption costs the reliability of electricity supply can be described the whole distribution area by the standard IEEE 1366 which defines some key ratios: System average interruption frequency SAIFI, System average interruption duration index SAIDI, Customer average interruption duration index CAIDI, and Momentary average interruption frequency MAIFI. (Lakervi 2009; Lakervi 1995)

System average interruption frequency
$$SAIFI = \frac{\sum n_j}{N_s} \tag{4.1}$$

System average interruption duration index
$$SAIDI = \frac{\sum_i \sum_j t_{ij}}{N_s} \tag{4.2}$$

Customer average interruption duration index
$$CAIDI = \frac{\sum_i \sum_j t_{ij}}{\sum_j n_j} \tag{4.3}$$

In the equations:

$\sum n_j$ = The total number of customer interruptions

N_s = Total number of customers

t_{ij} = Duration of interruption i to customer j

i = Number of interruptions during a certain time period

j = Number of customers inside fault area

Most of the interruptions observed by the customers are from the medium voltage network. When observing a radially used medium voltage network the amount of the interruptions, the duration and the interruption costs of customers attached to it, can be calculated by the following equations. In the equations, lower index j points to the customer and lower index i means a network component.

The interruption frequency $$f_j = \sum_{i \in l} f_i \tag{4.4}$$

Interruption duration per year $$U_j = \sum_{i \in l} f_i \cdot t_{ij} \tag{4.5}$$

The average duration of interruption $$t_j = \frac{U_j}{f_j} \tag{4.6}$$

The undelivered energy $$E_j = f_j \cdot t_j \cdot \Delta P_j \tag{4.7}$$

The costs of the interruption $$K_j = \sum_{i \in l} f_i \left[a_j + b_j(t_{ij}) t_{ij} \right] \Delta P_j \tag{4.8}$$

In the equations:

f = fault frequency

t = interruption time resulted by the fault

ΔP = the average interruption power

a = the value of the damage of the power loss

b = the value of the damage of the energy loss

The interruption costs are usually evaluated with a constant that is comparable to the power, the parameter a in equation 4.8, and with a constant that is comparable to the time of the interruption, the term b in the equation 4.8. The interruption costs depend highly on what kind of consumers are in the area of the interruption. The costs caused by the interruptions have been valuated financially with interruption-parameters which are presented in the following Table 4.1. The unit of parameter A is €/kW and B is €/kWh, and they can be bluntly applied to the equation 4.8. KAH-parameter are the abbreviation used from interruption-parameters. (Lakervi 2009; Lakervi 1995)

Table 4.1. *KAH-parameters (Lakervi 2008).*

	Unexpected		**Planned**		**PJK**	**AJK**
	A	*B*	*A*	*B*	*A*	*B*
Household	0,36	4,29	0,19	2,21	0,11	0,48
Agriculture	0,45	9,38	0,23	4,8	0,2	0,62
Industry	3,52	24,45	1,38	11,47	2,19	2,87
Public	1,89	15,08	1,33	7,35	1,49	2,34
Service	2,65	29,89	0,22	22,82	1,31	2,44

The bigger the value of the KAH-parameter is the more fault sensitive the customer type is. In this case the cost of interruption of a fault is bigger to industry services and public than for households and agriculture.

The reliability of the distribution network is often evaluated by a reliability based network analysis abbreviated RNA. The RNA is often an application in the network information systems. In this thesis, the reliability calculations are done by RNA application of the Tekla NIS programme. On the half of 20 kV distribution network and LVDC system, the reliability is evaluated using the equations above.

The idea of the calculation results from the RNA-application of Tekla NIS programme is to help finding out the so called weak spots in the network and provide information about the reliability of the networks to the needs of designing. In this version there is also functionality for calculating the voltage dips as a part of the network analysis. (Tekla 2011)

The RNA provides information about the reliability combined with the information about the interruptions of the customers. The computing can be divided into two issues. Interruption *caused* by a certain part of the network is called the *cause based calculation*. The interruption *experienced* by customers and transforming substations is called the *experience based calculations*. The results from the experience based calculations show how customers (LV) and transforming circuits (MV) experience the unreliability of the network. On the other hand, the cause based results consist of the reasons for the unreliability of the network. The cause based calculations present how much different network components create unreliability to the network company and to the customers of it.

The topology of the substations output, components and the fault location effects the amounts of the interruptions and their duration. Other effecting factors are the existence of the backup electrical supply and the automation in the network. Utilizing the information mentioned above the Tekla NIS RNA calculates the reliability from a substation to a level of one individual distribution transformer. (Tekla 2011)

4.2 Reliability of 20 / 0,4 kV distribution network

The reliability of the two MV feeders is examined in the networks present state and when the possible replaceable branch lines are replaced with cable.

The figure f_{ajk} means the annual number of long autoreclosures and the figure f_{pjk} means the annual number of quick autoreclosures. The basic reliability figures of MV feeder 11 KST_KIVIJÄRVI are presented in Table 4.2

Table 4.2. *The reliability figures of MV feeder 11 KST_KIVIJÄRVI.*

Network	f_i [faults/a]	f_{ajk} [faults/a]	f_{pjk} [faults/a]	U_j [h/a]	t_j [h/fault]
Present	3,99	1,22	6,92	3,54	0,89
When selected branch lines are Cabled	3,49	1,09	6,19	3,20	0,92

In Table 4.3 are presented the SAIFI, SAIDI and CAIDI indexes for the MV feeder 11 KST_KIVIJÄRVI.

Table 4.3. *SAIDI, SAIFI and CAIDI of the MV feeder 11 KST_KIVIJÄRVI.*

Network	SAIFI	SAIDI	CAIDI
Present	3,30	3,95	1,20
When selected branch lines are Cabled	2,95	3,60	1,22

The reliability cost in practise means the costs which are caused by interruptions, the KAH-parameters are used when calculating those costs. The interruption costs of the present network and when the branch lines are cabled on MV feeder 11 KST_KIVIJÄRVI are presented in Table 4.4. Table 4.4 presents how many customers of a certain type there are in this MV feeder. There are also the average powers of the customer types on the MV feeder. The average energies of the customer types are also used when calculating the interruptions costs for the MV feeder with LVDC-links. The effect areas of faults in different places on MV feeder are presented in Figure 4.3.

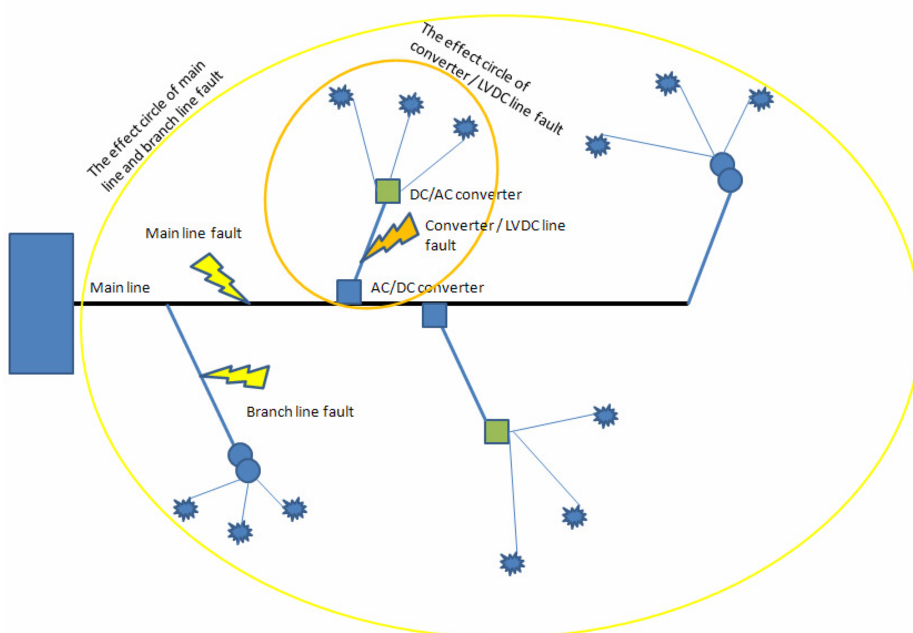

Figure 4.3. *The effect areas of faults in LVDC-lines, converters, main and branch lines.*

The average power of the customer is calculated from the energy consumption data collected from TEKLA NIS programme for each transforming circuit. Then the annual energy is divided by the number of customers of the specific type and full load hours.

Table 4.4. *Annual interruption costs of MV feeder 11 KST_KIVIJÄRVI.*

Type of customer	House-hold	Agri-culture	Industry	Public	Service	Sum
Number of customers	189	7	7	4	11	218
Energy of the group [kWh]	1086376	197133	270425	29760	162969	1746663
Average power/customer [kW]	2	10	13	3	5	3
Interruption costs of present network [€]	5 770	2 267	8 321	562	6 038	22 958
Ajk costs present net-work [€]	217	51	323	29	166	786
Pjk costs present net-work [€]	283	93	1400	105	505	2 386
Sum of interruption costs of present network [€]						**26 130**
Interruption costs of cabled network [€]	5 226	2 051	4 630	510	5 470	17 887
Ajk costs branches cabled [€]	194	46	289	26	148	703
Pjk costs branches cabled [€]	253	83	1 252	94	451	2 133
Sum of interruption costs when branches cabled [€]						**20 723**

The same reliability figures that are presented in Tables 4.2 and 4.3 for the MV feeder 11 KST_KIVIJÄRVI are presented for the MV feeder 03 LSJ_MIEKKO in the following Tables 4.5 and 4.6.

Table 4.5. *The reliability figures of MV feeder 03 LSJ_MIEKKO.*

Network	f_i [faults/a]	f_{ajk} [faults/a]	f_{pjk} [faults/a]	U_j [h/a]	t_j [h/fault]
Present	4,04	2,99	16,96	2,80	0,69
When selected branch lines are cabled	3,17	2,70	15,29	2,17	0,68

Table 4.6. *SAIDI, SAIFI and CAIDI of the MV feeder 03 LSJ_MIEKKO.*

Network	SAIFI	SAIDI	CAIDI
Present	4,33	3,09	0,71
When selected branch lines are cabled	3,45	2,45	0,71

The interruption costs of the present network and when the branch lines are cabled on MV feeder 03 LSJ_MIEKKO are presented in the following Table 4.7.

Table 4.7. *Annual interruption costs of MV feeder 03 LSJ_MIEKKO.*

Type of customer	House-hold	Agri-culture	Industry	Public	Service	Sum
Number of customers	309	5	2	3	13	332
Energy of the group	1550209	105050	79821	35880	1154640	2925600
Average power/customer [kW]	2	9	17	5	38	4
Interruption costs of present network [€]	8 126	1 189	2 434	671	42 240	54 660
Ajk costs present network [€]	942	82	290	106	3 565	4 985
Pjk costs present network [€]	1 224	151	1 255	564	12 348	15 541
Sum of interruption costs of present network [€]						**75 186**
Interruption costs of cabled network [€]	6 338	924	1 909	525	32 959	42 655
Ajk costs branches Cabled [€]	850	74	262	96	3 219	4 501
Pjk costs branches cabled [€]	1 103	136	1131	346	9 787	12 503
Sum of interruption costs when branches cabled [€]						**59 659**

4.3 The reliability of distribution network with LVDC-link

When, calculating the reliability of the LVDC-link the number autoreclosures can be assumed to be the same as when the branch lines are cabled. The costs are not the same because the capacitors of the converters are able to supply the customers for the time of quick autoreclosures.

The average duration of fault in 20 kV cable network is 2,9 h and the average failure rate of 20 kV cable is 0,0138 fault/km, a. Both of these measures are based on statistics from LNI's network years 2008 and 2009. The mean time between failure rate of an inverter is approximately 3 years which means that the number of faults in the LVDC-link can be assumed to be 0,33333 faults per year. In these studies the interruption time of a converter fault is assumed to be the same as in 20 kV cable fault. The work interruption costs are assumed to be the same as is the 20 kV cabling. (LUT 2010)

The reliability of the MV feeders with LVDC-links is calculated in two parts. The first part is the reliability of the network where the replaceable branch lines are removed and then the RNA analysis is run. The second part is the reliability analysis of the branch lines, which is Excel based calculations.

In the following Table 4.8 are presented the most common reliability figures of the MV feeder 11 KST_KIVIJÄRVI. The figures are presented separately for the branch lines as LVDC-links and the rest of the MV feeder.

Table 4.8. *Reliability figures of the MV feeder 11 KST_KIVIJÄRVI*

Network	f_i [faults/a]	f_{aik} [faults/a]	f_{pik} [faults/a]	U_i [h/a]	t_i [h/fault]
Main line	3,31	0,86	4,86	2,75	0,83
One LVDC-link	0,33	0,86	0	0,85	2,54

The system average interruption duration index, system average interruption frequency index and customer average interruption duration index of MV feeder 11 KST_KIVIJÄRVI are presented in the following Table 4.9.

Table 4.9. *SAIDI, SAIFI and CAIDI of the MV feeder 11 KST_KIVIJÄRVI.*

SAIFI	**SAIDI**	**CAIDI**
1,37	1,51	1,10

In Table 4.10 are presented the interruption costs of the MV feeder 11 KST_KIVIJÄRVI. The work interruption costs are assumed to be the same as they are for the cabled network. The interruption costs are calculated using the parameters in Table 4.1.

Table 4.10. *Annual interruption costs of the MV feeder 11 KST_KIVIJÄRVI when LVDC-links are placed.*

Type of customer	**House-hold**	**Agri-culture**	**Industry**	**Public**	**Service**	**Sum**
Number of custom-ers	68	4	0	0	4	76
Average power of the group [kW]	134	38	0	0	20	240
Interruption costs [€]	1 623	1 010	0	0	1 718	4 351
Ajk costs [€]	312	116	0	0	240	668
Pjk costs [€]	71	37	0	0	129	238
Sum of interruption costs of the main lines [€]						**5 257**
Number of custom-ers	121	3	7	4	7	142
Average power of the group [kW]	238	29	92	10	35	404
Interruption costs of the LVDC links caused by the faults in main line [€]	2 889	758	6 537	441	3 006	13 631
Interruption costs caused by the con-verters [€]	949	242	2 238	149	991	4 569
Ajk costs on the LVDC-links [€]	98	87	227	116	74	602
Pjk costs on the LVDC-links [€]	0	0	0	0	0	0
Sum of interruption costs of LVDC-links [€]						**18 802**
Total interruption costs of the MV feeder including LVDC-links [€]						**24 059**

In the following Table 4.11 are presented the same reliability figures for the MV feeder 03 LSJ_MIEKKKO as are in Table 4.8 for the MV feeder 11 KST_KIVIJÄRVI.

Table 4.11. *The reliability figures of the MV feeder 03 LSJ_MIEKKO*

Network	f_i [faults/a]	f_{ajk} [faults/a]	F_{pjk} [faults/a]	U_i [h/a]	t_i [h/fault]
Main line	2,98	2,11	11,91	1,94	0,65
One LVDC-link	0,33	2,11	0	0,85	2,54

The system average interruption duration index, system average interruption frequency index and customer average interruption duration index of MV feeder 03 LSJ_MIEKKO are presented in the following Table 4.12. The calculation equations of these indexes are presented earlier in this thesis (equations 4.1-4.3).

Table 4.12. SAIDI, SAIFI and CAIDI of the MV feeder 03 LSJ_MIEKKO.

SAIFI	SAIDI	CAIDI
1,41	1,29	0,92

In Table 4.13 are presented the interruption costs of the MV feeder 03 LSJ_MIEKKO. The work interruption costs are assumed to be the same as they are for the cabled network. The interruption costs are calculated using the parameters in Table 4.1.

Table 4.13. Annual interruption costs of the MV feeder 04 LSJ_MIEKKO when LVDC-links are placed.

Type of customer	House-hold	Agri-culture	Industry	Public	Service	Sum
Number of custom-ers	117	3	2	2	11	135
Average power of the group [kW]	248	27	34	10	413	503
Interruption costs [€]	2 157	497	1 721	315	25 071	29 761
Ajk costs [€]	251	35	204	50	2 120	2 660
Pjk costs [€]	691	565	14 881	909	6 451	23 497
Sum of interruption costs of the main lines [€]						**55 918**
Number of custom-ers	192	2	0	1	2	197
Average power of the group [kW]	408	18	0	5	75	506
Interruption costs of the LVDC links caused by the faults in main line [€]	3 539	332	0	158	4 558	8 587
Interruption costs resulted by con-verters [€]	1 628	149	0	74	2 102	3 953
Ajk costs on the LVDC-links [€]	411	23	0	25	386	845
Pjk costs on the LVDC-links [€]	0	0	0	0	0	0
Sum of interruption costs on the LVDC-links [€]						**13 385**
Total interruption costs of the MV feeder including LVDC-links [€]						**69 303**

4.3.1 Reliability of LVDC system

Firstly in this chapter is defined the reliability of the LVDC-system only, the single components of the LVDC system and after it there is a examination of reliability of the distribution network with the LVDC-link placed on the branch lines introduced before in chapter 4.1. The reliability study of the whole MV feeder with LVDC links is done in similar way as the reliability study when the branch lines are replaced with cable.

Reliability is often defined as the probability that a device will performs its required function under stated conditions for a specific period of time. The reliability of the

LVDC systems consists of several different fields. One of the significant factors in the reliability of the LVDC systems is the single components in the system, their lifetime and the need of maintenance. In this study the emphasis is on the converter components. The lifetime reliability consists of the single components reliability. As earlier was described the most simple LVDC system consists of inverter, rectifier, and the DC cable, a principal structure presented is in Figure 4.3.

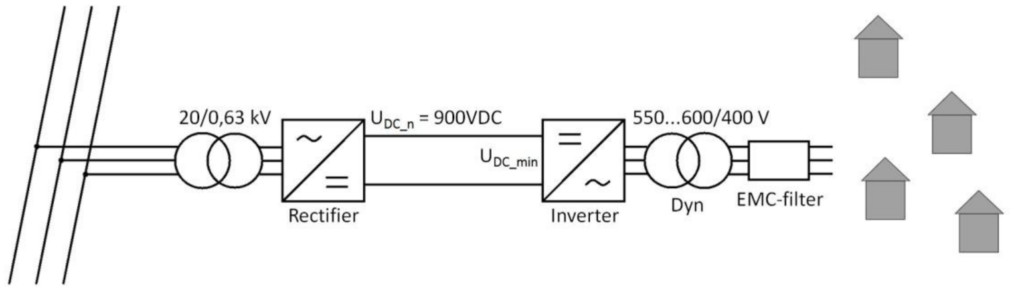

Figure 4.3. *Principal structure of a LVDC system. (Hakala 2012)*

One of the widely used indexes in reliability studies is the mean time between failures (MTBF). It is the mean time period between system failures due to the random failures of one of its component parts in other words it tells how long a system is expected to work without failing. One other factor that affects on the overall availability of the system depends also on the repair time. This is called the mean time to repair (MTTR).

4.3.2 Reliability of the DC components

Like Figure 4.3 shows there are only few network components that can be classified as DC components. These DC components are: rectifiers, DC-cables and inverters. Of course these networks components are build from smaller power electronic parts. The reliabilities of the most important ones of those power electronic parts are presented in the following Chapters 4.1.1 Rectifiers and 4.1.2 Inverters.

Rectifiers

Rectifiers have been used for a long period of time in industrial applications of a different kind and from that use LUT has collected data. From the collected data, LUT has made some approximations about the lifetime of rectifiers' components and meantime between failures (MTBF) of the rectifier. In the following Table 4.14 is presented the approximated lifetimes of the rectifier's components. The approximated MTBF for rectifiers is 4-5 years and the expected technical lifetime is 10-15 years. (LUT 2010)

Table 4.14. Approximated lifetimes of rectifier's components (LUT 2010)

Rectifier bridge	
Component	**lifetime [a]**
IGBT	5-10
Thyristor	15-20
Diodes	15-20
Capacitor (ELKO)	4-6

Inverters

Inverters have been used in industrial applications of a different kind for quite a while. From the industrial use, LUT has collected data about the lifetimes of some components in the inverters. In the following Table 4.15 is presented the empirical approximations of the lifetime. The approximated meantime between failures (MTBF) for an inverter is 2-3 years and the expected technical lifetime is 10-15 years. (LUT 2010)

Table 4.15. Approximated lifetimes of inverter's components (LUT 2010)

Inverter bridge	
Component	**lifetime [a]**
IGBT	5-10
Thyristor	15-20
Diodes	15-20
Capacitor (ELKO)	4-6

Cable

The idea in building LVDC-links is to utilize the existing AC low voltage cables with DC voltage. This means that the cables need to be tested for their DC voltage endurance. So far the biggest reason for concern has been the polarization of the insulation material of the cables. When the electric field over the cable insulation material is strong enough starts the forming of space charges. The forming of space charges means that the charge carries starts to build up in the insulation material. According to some literature sources, the space charges should not build up until the magnitude of the electrical field over the insulation is less than 7 kV/mm. The electric field over the cable insulation has been studied in the master's thesis of Suntila 2009.

Because the effects of the low DC voltage over the cable do not differ too much from the low AC voltage it can be assumed that the reliability of the cable in LVDC applications is roughly the same as in LVAC applications.

4.3.3 Lifetime reliability of LVDC system

The most disposed primary components in power electronic devices are electrolytic capacitors, fans and the power switches of output stage. (LUT 2010) In the following Table 4.16 are presented the approximated lifetimes of control circuit of the converters and the power supply of the control system.

Table 4.16. *The approximated lifetimes of power supply of the control system and control circuit. (LUT 2010)*

Power supply of the control system		Control circuit	
Component	**Lifetime [a]**	**Component**	**Lifetime [a]**
Transistor (FET)	10-15	Capacitor	15-20
Capacitor (ELKO)	4-6	Processor	15-20
Super capacitors	10-15	Voltage regulator	10-15
Diodes	15-20		
Fuses	10-15		
Varistor	10-15		

In Table 4.17 are presented the approximated lifetimes of filters and fans of the converters.

Table 4.17. *Approximated lifetimes of filters and cooling. (LUT 2011)*

Filters		Cooling	
Component	**lifetime [a]**	**Component**	**lifetime [a]**
Inductance	25-30	Fan	2-4
Polyester capacitor	15-20	Air filter	1-5

From Tables 4.14 and 4.15 can be seen the switching component of the converter plays a significant role in the lifetime of a converter. Where the diode and thyristor constructed converters approximated lifetime is 15-20 years, the converter which constructs of IGBT-components is only 5-10 years. From the approximations of presented above can be made an assumption that a lifetime of an IGBT-converter is shorter than a lifetime of a diode or a thyristor converter.

The lifetime of the components and MTBF depends greatly on the converters placing environment and the features of the loading. The most significant factors are the operating temperature and the fluctuation in loading and loadings cyclicity.

4.3.4 Comparison of the reliability between LVDC-link and consumer specific inverting

The biggest difference between the LVDC-link and the consumer specific converting is the number of the inverters. In LVDC-link there is only one inverter and in the consumer specific there is an inverter for every customer. When the amount of network components increases, the probability of faults increases. This means that the probability of a fault in LVDC- link is smaller than a fault in consumer specific inverting.

If there was a fault in the LVDC-link's inverter, it would cause an interruption for more than one customer and would effect on more customers than if the fault were in the consumer specific inverter where it would effect on only one customer. In case of an inverter fault, the system reliability is better when the inverting is consumer specific.

4.3.5 Challenges

The challenge of changing environmental circumstances increase the uncertainty of the lifetimes approximated in industrial applications.

The biggest challenge in determining the reliability of LVDC system is that there is no research data of it. This is because it is a new technology in distribution networks and the only using experiences come from HVDC and industrial processes. On the other hand, the research data of MTBF of the converters is often classified as a business secret among manufacturers.

4.4 Summary of interruption costs

The hindrances of interruptions are monetary values that interruptions cause to the customers. The monetary value depends highly on the type of the customer. The above calculated interruption costs are presented in the following two figures. The first Figure 4.4 shows the total fault interruption costs of the MV feeder 11 KST_KIVIJÄRVI with each network topology. The interruption costs are presented as a sum of each customer group's interruption costs.

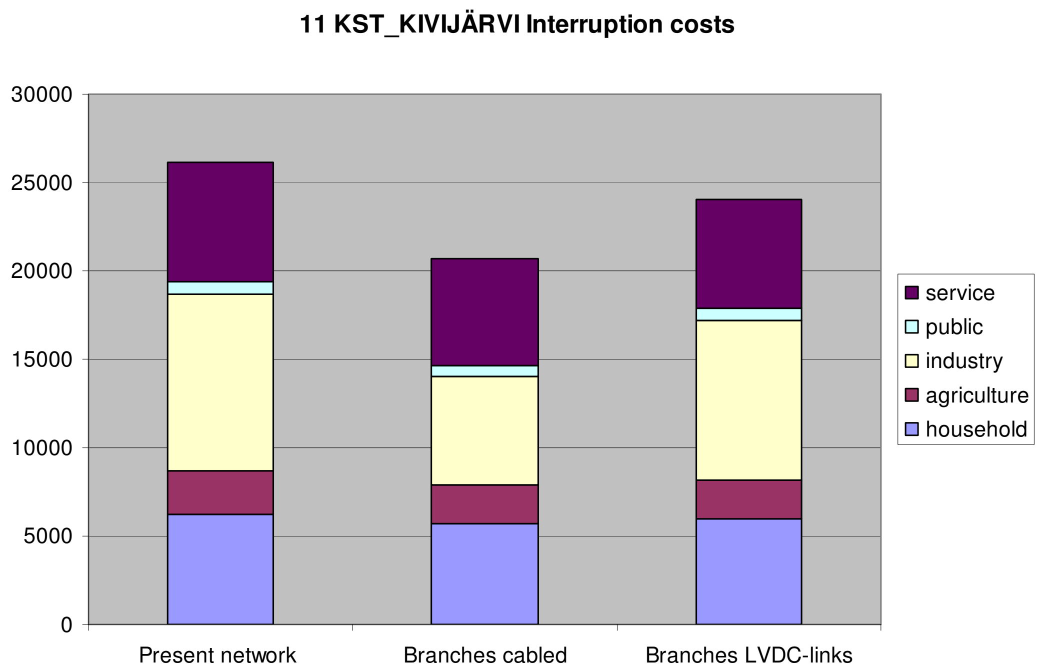

Figure 4.4. *The total fault interruption costs on MV feeder 11 KST_KIVIJÄRVI.*

The first column in Figure 4.4 presents the fault interruption costs of the present network. The second column presents the fault interruption costs when the possibly replaceable branch lines are cabled with 20 kV cable. The third column presents the interruption costs when the possibly replaceable branch lines are LVDC-links.

In Figure 4.5 are shown the fault interruption costs of the MV feeder 03 LSJ_MIEKKO. In the figure there are columns for each of the network topology options.

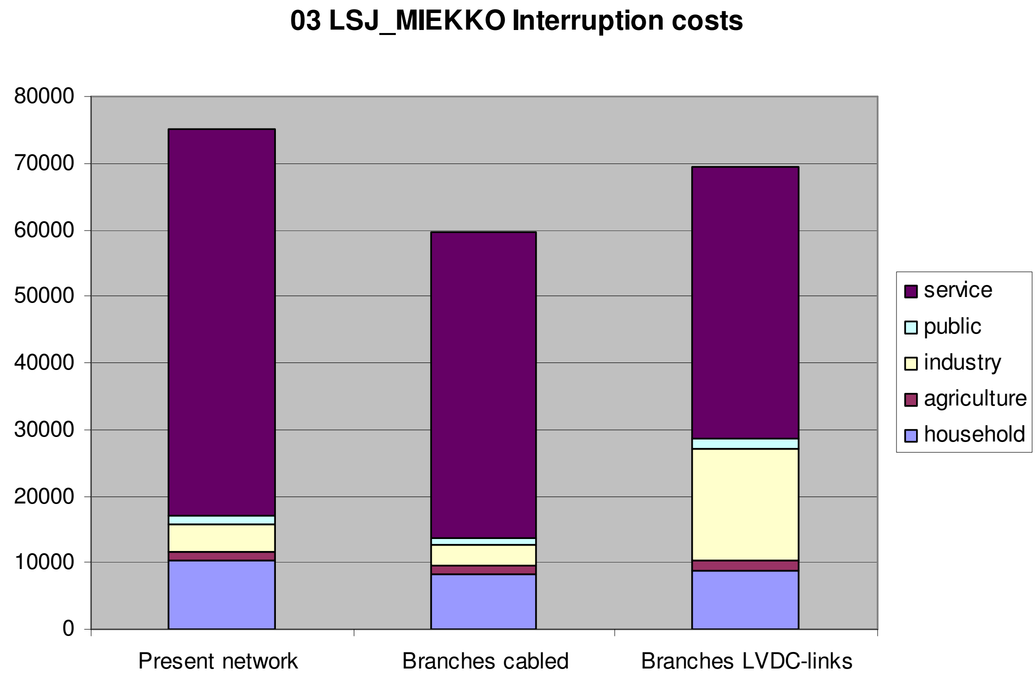

Figure 4.5. *The total fault interruption costs on MV feeder 03 LSJ_MIEKKO.*

The first column in Figure 4.5 presents the fault interruption costs of the present network. The second column presents the fault interruption costs when the possibly replaceable branch lines are cabled with 20 kV cable. The third column presents the interruption costs when the possibly replaceable branch lines are LVDC-links. The columns consist of hindrance costs of each customer type service, public, industry, agriculture and household.

The annual value of the interruption cost depends highly of the type of customers on the MV feeders and the average energy consumption of the customer type. Even though the households are the biggest customer group on both MV feeders they are only the third biggest source of interruption costs. The reasons for the household being only the third biggest source of interruption costs are the low average consumption of energy and lower hindrance parameters than the parameters of the other customer types. The reasons for the services and industry to be the two biggest sources of interruption costs are their relatively large consumption of energy and their bigger fault sensitivity comparing with the other customer types.

As from Figure 4.5 can be seen the fault interruption costs of industry are much higher on the LVDC column than on the cable or present, the explanation for it is that the fault sensitive industrial customers are at the end of LVDC-links which are more fault inclined than cable and overhead lines. The bigger fault inclination of LVDC-links results from the power electronic components which have a higher risk of failure than the traditional network components like transformers and circuit breakers.

5 COST CALCULATIONS

The cost calculations consist of four separate divisions which are investment costs, costs caused by losses, maintenance costs and fault repair costs. Each of these costs is handled in their own chapter. The cost calculations are done to the MV feeders and branch lines which are presented in the beginning of the previous Chapter 4.

5.1 Investment costs

The investment cost means the costs which result from constructing new network or reconstructing the old one. In this thesis the investment cost calculations are based on unit prices defined by Energy Market Authorities (EMV). In the following Table 5.1 are presented the prices used in calculations.

Table 5.1. *EMV unit prices for network components. (EMV 2012)*

Component	Unit	Unit price [€]	Component	Unit	Unit price [€]
1-Column transformer	Pcs.	4 860	500 – 630 kVA Transformer	Pcs.	9 800
2-Column transformer	Pcs.	6 470	PAS 35 – 70 Overhead line 20 kV	Km	28 970
Transformer substation (outside maintained)	Pcs.	23 680	PAS 95 or bigger overhead line 20 kV	Km	31 030
Transformer substation (inside maintained)	Pcs.	32 800	≥ 70 Cable 20 kV	Km	23 660
Light transformer substation	Pcs.	8 850	95 – 120 Cable 20 kV	Km	31 160
30 kVA Transformer	Pcs.	3 240	35 – 50 Cable 0,4 kV	Km	8 660
50 kVA Transformer	Pcs.	3 240	95 – 120 Cable 0,4 kV	Km	12 440
100 – 160 kVA Transformer	Pcs.	3 310	Cable construction 20 kV & 0,4 kV: Easy	Km	9 770
200 kVA Transformer	Pcs.	4 750	Cable construction 20 kV & 0,4 kV: Normal	Km	22 300
300 – 315 kVA Transformer	Pcs.	6 220	Cable construction 20 kV & 0,4 kV: Difficult	Km	63 690

5.1.1 20 kV distribution systems investment costs

The replaceable length of lines and the needed number of transformers and their sizes are listed in the following Table 5.2. In the Table there is also the present transformer size.

Table 5.2. *The sizes and number of the new transformers*

Transformers on MV feeder 11 KST_KIVIJÄRVI				Transformers on MV feeder 03 LSJ_MIEKKO			
Present		Planned		Present		Planned	
Size (kVA)	Number	Size (kVA)	Number	Size (kVA)	Number	Size (kVA)	Number
30	5	30	5	30	3	30	3
50	3	50	3	50	4	50	1
100	3	100	3	100	4	100	7
200	1	200	1	200	2	200	2
315	1	315	1				

In the following Table 5.3 is presented the whole length of replaceable branch lines, which are used in investment cost calculations.

Table 5.3. *The replaceable lengths of branch lines used in calculations.*

MV Feeder	Length (km)
11 KST_KIVIJÄRVI	7,572
03 LSJ_MIEKKO	7,722

The networks present value can be calculated following the equation 5.1 below (EMV 2011). Networks NPV gives the value of the present network. In this study it is used as a reference for the cabling and LVDC investment costs.

$$NPV = (1 - \frac{aa}{plt}) \cdot rv \qquad (5.1)$$

In the equation:
aa = Average age of the components
plt = The real lifetime of the component
rv = The replacement value

In the NPV values presented in Tables 5.4 and 5.5, the planned lifetime of the components is 40 years and the average age of the component is presented in the age column. The number of units column contains either length of the line or number of pieces. The investment costs on the right end column of the Tables 5.4 and 5.5 are the costs which are created if the network would be replaced exactly the same as it is at the moment.

The average age of the components on the MV feeder 11 KST_KIVIJÄRVI is 36 years and the average of the components on MV feeder 03 LSJ_MIEKKO is 29. On the basis of the average ages can be approximated that the replacement investment of the components will be within 5 years on the MV feeder 11 KST_KIVIJÄRVI and within 10 years on the MV feeder 03 LSJ_MIEKKO.

Table 5.4. *The networks present value of the replaceable branch lines on MV feeder 11 KST_KIVIJÄRVI.*

Component	Number of units	Age, [a]	Unit price [€]	NPV [€]
Sp40, [km]	5,374	37	20 030	27 987
Sw25, [km]	0,246	49	20 030	99
FeS25, [km]	1,952	34	20 030	12 512
Transformer 30	5	36	3 240	4 536
Transformer 50	4	33	3 310	4 502
Transformer 100	4	39	4 750	4 180
Transformer 200	1	43	6 220	871
Transformer 315	1	18	7 650	4 896
1-Column transformer	8	34	4 860	12 442
2-Column transformer	5	38	6 470	7 764
Total costs				**79 787**

Table 5.5. *The networks present value of the replaceable branch lines on MV feeder 03 LSJ_MIEKKO.*

Component	Number of units	Age, [a]	Unit price [€]	NPV [€]
PAS 120, [km]	0,131	14	31 030	2 927
Rv63, [km]	0,826	21	23 750	11 378
Sp40, [km]	6,024	34	20 030	38 611
Sw25, [km]	0,738	41	20 030	2 661
Transformer 30	3	30	3 240	3 888
Transformer 50	4	35	3 310	3 972
Transformer 100	4	35	4 750	5 700
Transformer 200	1	17	6 220	4 105
1-Column transformer	1	28	4 860	2 138
2-Column transformer	12	32	6 470	27 950
Total costs				**103 331**

Cabling

On the following Tables 5.6 and 5.7 are calculated the cabling costs of the replaceable branch lines to both MV feeders. The transformer sizes are evaluated from the power consumption of customers on the specific branch line. The cable joints are needed every 500 m because 20 kV cable reels holds 500 m of cable.

Table 5.6. The costs of each component needed in the MV feeder 11 KST_KIVIJÄRVI.

MV feeder 11 KST_KIVIJÄRVI			
Component	**Number/Length**	**Unit price [€/pcs]**	**Total [€]**
Transformer 30	5	3 240	16 200
Transformer 50	3	3 310	9 930
Transformer 100	3	4 750	14 250
Transformer 200	1	6 220	6 220
Transformer 315	1	7 650	7 650
Transforming substa-tion	13	8 850	115 050
Cable 95	7,572	31 160	235 944
Construction of cable: Easy	7,172	9 770	70 070
Construction of cable: Normal	0,4	22 300	8 920
Substation cable end	13	1220	15 860
Pole cable end	13	2290	29 770
Cable joint	14	1940	27 160
Altogether			**557 024**

Table 5.7. The costs of each component needed in the MV feeder 03 LSJ_MIEKKO.

MV feeder 03 LSJ_MIEKKO			
Component	**Number/Length**	**Unit price [€/pcs]**	**Total [€]**
Transformer 30	3	3 240	9 720
Transformer 50	1	3 310	3 310
Transformer 100	7	4 750	33 250
Transformer 200	2	6 220	12 440
Transforming substa-tion	13	8 850	115 050
Cable 95	7,722	31 160	240 618
Construction of cable: Easy	7,722	9 770	75 444
Substation cable end	13	1 220	15 860
Pole cable end	13	2 290	29 770
Cable joint	15	1 940	29 100
Altogether			**489 831**

5.1.2 LVDC systems investment costs

In this chapter, the investment costs are calculated for the parts of LVDC-link for which there are available EMV prices. In practise this means that the investment cost of the power electronics in LVDC system is evaluated in Chapter 6 where the total lifetime costs are calculated for each distribution system topology.

From the EMV price sheet, we can find the prices for the transformers, cables and the construction of the cable. The costs of the LVDC-link are collected into the following Tables 5.8 and 5.9. At Table 5.8 is presented the investment costs of components needed on the MV feeder 11 KST_KIVIJÄRVI. In both MV feeders the needed number of distribution transformers is double compared with the cabling investment this is due to the need of the galvanic isolation transformer after the inverter.

Table 5.8. *The costs of each component needed in the MV feeder 11 KST_KIVIJÄRVI.*

MV feeder 11 KST_KIVIJÄRVI			
Component	**Number/Length**	**Unit price [€/pcs.]**	**Total [€]**
Transformer 30	10	3 240	32 400
Transformer 50	6	3 310	19 860
Transformer 100	6	4 750	28 500
Transformer 200	2	6 220	12 440
Transformer 315	2	7 650	15 300
Transforming sub-station	13	8 850	115 050
Cable 95 / 0,4 kV	7,572	12 440	94 196
Construction of ca-ble: Easy	7,172	9 970	71 505
Construction of ca-ble: Normal	0,4	22 300	8 920
Altogether			**398 171 ***

* Excluding power electronics investment costs

In Table 5.9 is presented the investment costs of components needed on the MV feeder 03 LSJ_MIEKKO.

Table 5.9. *The costs of each component needed in the MV feeder 03 LSJ_MIEKKO.*

MV feeder 03 LSJ_MIEKKO			
Component	**Number/Length**	**Unit price [€/pcs.]**	**Total [€]**
Transformer 30	6	3 240	19 440
Transformer 50	2	3 310	6 620
Transformer 100	14	4 750	66 500
Transformer 200	4	6 220	24 880
Transforming substa-tion	13	8 850	115 050
Cable 95/ 0,4 kV	7,722	12 440	96 062
Construction of cable: Easy	7,722	9 770	75 444
Altogether			**403 996 ***

* Excluding power electronics investment costs

As from the Tables can be seen the costs of the rectifier and inverter are not presented and it is because they are not known. The price of the converter is evaluated in Chapter 6 where the life time costs of each distribution system are calculated.

5.2 The costs caused by losses

In distribution networks, most of the losses are caused by the low voltage network. In this master's thesis study the low voltage networks losses can be left out of the estimations because they are the same in each case. This means that the AC low voltage networks topology does not change.

The amount of loss is usually reported as the loss of energy in the network. The costs caused by losses are usually calculated as Euro per kilo Watt hour (€/kWh). The losses formed in the distribution network in power transmission are costs that the distribution network company needs to buy from the energy seller.

The price of the energy loss can be determined as the same as the market price of the energy. In this study, the price is evaluated to be 50 €/kWh which very close to the present market price of energy and near the long term average energy price of LNI Verkko Oy. The energy loss of the system can be calculated as a multiplication product of the power loss and time the same way as the consumption energy is calculated. In this study, the observation period is one year which is 8760 hours.

The power loss in the DC-cable can be calculated with the following equation 5.1 when the voltage drop in the line and line resistance is known.

Power loss in the cable $$P_{loss} = \frac{U_{drop}^2}{R_{cable}} \quad (5.1)$$

Where the U_{drop} is the voltage drop of the line and in the LVDC-link study it is 10 %. The R_{cable} is the resistance of the cable, which depends on the length of the cable.

5.2.1 20 / 0,4 kV distribution

The amount of the power losses of the existing network and the cabled network can be found from the load flow calculation of Tekla NIS programme. In the following Table 5.10 is presented the MV feeders 11 KST_KIVIJÄRVI and 03 LSJ_MIEKKO annual energy loss costs when there has not been made any changes to the network.

Table 5.10. *The annual energy loss costs of the present MV feeders.*

11 KST_KIVIJÄRVI				**03 LSJ_MIEKKO**			
	Power loss [kW]	Energy loss [MWh]	Cost [€]		Power loss [kW]	Energy loss [MWh]	Cost [€]
Cable + Transformer of branch lines	2,0	17,7	885	Cable + Transformer of branch lines	6,5	56,8	2 838
The MV main line	0,4	3,2	162	The MV main line	3,8	33,0	1 651
Total	**2,4**	**20,9**	**1 047**	**Total**	**10,3**	**89,8**	**4 489**

The costs of the power losses of the MV feeders when the branch lines are cabled are presented in the Table 5.11 next page.

Table 5.11. *The annual energy loss costs of the MV feeders when the branch lines are cabled.*

11 KST_KIVIJÄRVI				03 LSJ_MIEKKO			
	Power loss [kW]	Energy loss [MWh]	Cost [€]		Power loss [kW]	Energy loss [MWh]	Cost [€]
Cable + Transformer of branch lines	2,1	18,2	911	Cable + Transformer of branch lines	6,1	53,1	2 654
The MV main line	0,4	3,2	162	The MV main line	3,8	33,0	1 651
Total	**2,5**	**21,5**	**1 073**	**Total**	**9,8**	**86,1**	**4 305**

5.2.2 Including LVDC system

The losses of LVDC system can be evaluated with the efficiency ratio of the LVDC system. The total efficiency ratio of the LVDC system consists of the efficiency of the distribution transformer, the efficiency of the rectifier, the voltage drop in the DC cable, the efficiency of the inverter and the efficiency of the galvanic isolation transformer. The efficiency ratios of transformers are 0,985 and the efficiency ratios of the converters are estimated to be 0,975. The efficiency effect of the EMC filter is estimated to have such little impact on the over all efficiency so it can be left unnoticed (Hakala 2012).

The total efficiency ratio of the LVDC system excluding the cable can be calculated as a multiplication product of the efficiency of the components. The estimation of the total efficiency ratio is 0,92. The resistance of the DC-cable is 0,641 Ω/km and the voltage drop is 90 V when the DC voltage is assumed to be 900 V. (Hakala 2012)

The total amount of power loss in the LVDC-link is the sum of the power loss of the cable and the power loss of the converters and the transformers. The amount of loss of the converters and the transformers can be calculated as a multiplication product of the loss ratio which is 1- efficiency ratio (1 - 0,92 = 0,08) and the average power that flows through the system. The average power flow through the LVDC-system is the sum of the average power that flows thorough the present distribution transformers. From Tekla NIS programme can be the found load curve for each distribution transformer and from the load curve can be calculated the average power, that flows thorough the distribution transformer annually. The average power flow thorough the distribution transformers at the end of each replaceable branch line to both MV feeders are presented in the following Table 5.12.

Table 5.12. *The average power flows thorough the distribution transformers in study.*

11 KST_KIVIJÄRVI		03 LSJ_MIEKKO	
Name of the transformer	$P_{average}$	Name of the transformer	$P_{average}$
Puulaaksontie	34,4	Alen	15,1
Niskala	28,2	Vatalammi	13,7
Heinämäki	17,8	Kaijansaari	16,9
Palovesi	10,2	Kyynärä	13,0
Naski	7,3	Luontokeskus	12,9
Lampila	4,9	Iisakinnokka	7,4
Pöngänperä	3,2	Vahas	7,4
Ranttila	3,8	Siirtola	8,6
Vastinki	3,9	Ruostejoki	9,0
Ketola	4,5	Mustjoki	2,8
Riekinpuro	6,1	Paskokanta	3,9
Rentola	3,5	Joensuu	1,5
Raiski	0,9	Välijoki	0,9
Total	**128,7**	**Total**	**113,1**

The energy loss costs of both MV feeders, when the replaceable branch lines are replaced with LVDC-links, are presented in the following Tables 5.13 and 5.14. In Table 5.13 are the annual energy loss costs of the whole MV feeder 11 KST_KIVIJÄRVI when the parameters used in calculation are the ones presented above.

Table 5.13. *The annual energy loss costs of MV feeder 11 KST_KIVIJÄRVI.*

11 KST_KIVIJÄRVI			
	Power loss [kW]	Energy loss [MWh]	Cost [€]
Cabled branch lines	1,7	14,6	731
Transformers & Converters	10,3	90,2	4 510
The MV main line	0,4	3,5	175
Total	**12,4**	**108,3**	**5 416**

In Table 5.14 are the annual energy loss costs of the whole MV feeder 03 LSJ_MIEKKO when the parameters used in calculation are the ones presented above.

Table 5.14. *The annual energy loss costs of MV feeder 03 LSJ_MIEKKO.*

03 LSJ_MIEKKO			
	Power loss [kW]	Energy loss [MWh]	Cost [€]
Cabled branch lines	1,6	14,2	712
Transformers & Converters	9,1	79,3	3 963
The MV main line	3,8	33,0	1 651
Total	**14,5**	**126,5**	**6 326**

5.3 Maintenance costs

The maintenance costs consist of the required component changes, annual inspections and the cost of the repairman. The maintenance costs can be divided into two sections: the costs of the planned maintenance and the costs of unplanned maintenance.

The unplanned maintenance costs are dependent on the fault frequency of the cable and converters and transformers. The cables fault frequency is the same that RNA calculations use and it is based on the fault statistics of the years 2008 and 2009. The total failure rate of 20 kV over headline is 0,075 fault/km a, cable 0,0275 fault/km a and the total failure rate of 0,4 kV cable is 0,0187 fault/km a.

The inspection costs consist of helicopter flights, walking inspections and targeted safety inspections. The planned maintenance costs consist mostly of tree clearing from the over headline street and some small maintenance work. The unplanned maintenance costs are the reparation costs of faults. The transformer inspection costs consist of condition inspection of the transformer, the basic service of the transformer, basic ground construction of the transforming substation and grounding measuring of the transformer.

In the following Table 5.15 are presented the annual number of faults of each line alternative. The number of faults in the Table 5.15 is only the number of faults on the replaceable branch lines, not the whole MV feeders.

Table 5.15. *Annual number of faults on the replaceable branch lines.*

MV Feeder	**Number of faults/a**		
	20 kV OHL	20 kV cable	0,4 kV cable
11 KST_KIVIJÄRVI	0,57	0,21	0,14
03 LSJ_MIEKKO	0,58	0,21	0,14

5.3.1 20 / 0,4 kV distribution

In the following Table 5.16 are presented the maintenance costs of the present network of both MV feeders. All the maintenance costs are calculated as an annual sum.

Table 5.16. *The maintenance costs of the present network of both MV feeders.*

	Unit price	11 KST_KIVIJÄRVI	03 LSJ_MIEKKO
Transformer inspection	24,9 €/pcs, a	323 €/a	323 €/a
Inspection	29,3 €/km, a	222 €/a	226 €/a
Maintenance (Planned)	90,0 €/km, a	681 €/a	695 €/a
Total		**1226 €/a**	**1244 €/a**

In Table 5.17 are presented the maintenance costs of the MV feeders when the possible replaceable branch lines are replaced by cabling. At the moment LNI does not do any inspections on the 20 kV cables nor planned maintenance.

Table 5.17. *The maintenance costs of both MV feeders when branch lines are cabled.*

	Unit price	11 KST_KIVIJÄRVI	03 LSJ_MIEKKO
Transformer inspection	27,79 €/pcs, a	361,24 €/a	361,24 €/a
Inspection	0 €/km, a	0 €/a	0 €/a
Maintenance (Planned)	0 €/km, a	0 €/a	0 €/a
Total		**361 €/a**	**361 €/a**

5.3.2 Including LVDC system

The LVDC-links maintenance costs are presented in Table 5.18. The maintenance costs for the power electronics and converters are not yet known. The evaluation of the needed maintenance for the LVDC-link is described in following chapter Maintenance of the LVDC system. The inspection costs of the transformers is assumed to 0 € because the converters will be connected to the SCADA system and they are able to provide information of the state of the transformers and the transformers need of maintenance. The inspection cost of a converter is assumed to be the same as the inspection cost of a circuit breaker.

Table 5.18. *The maintenance costs of both MV feeders when branch lines are LVDC-links.*

Cable 0,4 kV / **LVDC**	Cost	11 KST_KIVIJÄRVI	03 LSJ_MIEKKO
Transformer inspection	0 €/pcs, a	0 €/a	0 €/a
Inspection of converters	40 €/pcs, a	1 040 €/a	1 040 €/a
Maintenance (Planned)	6,4 €/km, a	48,6 €/a	49,6 €/a
Maintenance of converters	-	-	-
Total		**1 089 €/a ***	**1 090 €/a ***

* Excluding maintenance material costs

As already mentioned the maintenance costs of the converters are unknown and they are evaluated later in this thesis.

Maintenance of the LVDC system

Maintenance plays an important role in improving the whole distribution systems reliability and in lengthening the lifetime of converters. As from the Tables 4.1-4.5 can be seen the cooling system and the electrolytic capacitors have the shortest lifetime. Lifetime of an air filter is 1-5 years and it strongly depends on the environment, the lifetime of a fan is 2-4 years and the lifetime of the electrolytic capacitor is 4-6 years. The inspection and maintenance frequency for the converters could be every five years though in very unclean environment the air filters might need changing more frequently than every five years. If the short lifetime components are replaced every five years during the maintenance, the lifetime of a converter could be 10-15 years.

5.4 Fault repair costs

The fault repair costs are the actual costs that the distribution network company pays for its subcontractors for repairing faults. The fault repair costs have nothing to do with the interruption costs. The fault repair costs consist of the work costs and the possible material costs. In LNI's network the work cost of 20 kV networks fault is 1000 €/fault. The material costs depend highly on which component is broken. With 20 kV overhead lines, the usual fault repair cost is the elimination of fallen trees from the lines. In cabled networks, the component which brokes most often is the cable-end or the transformer, but their fault rate is much smaller than the elimination rate of trees from the overhead lines. Although the trees from the overhead lines needs to be removed more often than the cable ends and transformers needs to be replaced in cabled networks the fault repair material cost of overhead lines is still estimated to be less that the cabled networks fault repair material cost.

The annual fault repair costs of the MV feeder 11 KST_KIVIJÄRVI are presented in the 5.19 below. The average fault material costs of LVDC-links are unknown.

Table 5.19. *The annual fault repair costs of MV feeder 11 KST_KIVIJÄRVI.*

Fault repair costs			
Type	Present	Branches cabled	Branches LVDC
Faults per year	3,99	3,49	7,64
Work	3 992,1	3 494,7	7 643,3
Sum	**3 992,1 € ***	**3 494,7 € ***	**7 643,3 € ***

* Excluding fault repair material costs

The annual fault repair costs of the MV feeder 03 LSJ_MIEKKO are presented on the Table 5.20 below. The average fault material costs of LVDC-links are also unknown with this MV feeder.

Table 5.20. *The annual fault repair costs of MV feeder 03 LSJ_MIEKKO.*

Fault repair costs			
	Present	Branches cabled	Branches LVDC
Faults per year	4,04	3,17	6,31
Work	4 037,4	3 170,9	6 313,3
Sum	**4 037,4 € ***	**3 170,9 € ***	**6 313,3 € ***

* Excluding fault repair material costs

The annual fault repair costs are just long term average fault repair costs. The real annual fault repair costs are highly dependent on the weather conditions of the year.

6 ECONOMICAL ANALYSIS OF THE LVDC

The economy of distribution network consists of several factors which are usually taken into notice when designing the becoming networks. These factors or cost factors are: investment or building costs, loss costs, disturbance costs and maintenance costs which are formed during the planned lifetime of the network. Economy of the distribution systems are often calculates as their lifetime costs which can be estimated with the following equation.

$$K_{life} = \sum_{t=1}^{T} \left[K_{inv}(t) + K_{los}(t) + K_{fr}(t) + K_{mai}(t) \right] \tag{6.1}$$

$K_{inv}(t)$ = The investment costs at time *t* (year *t*)

$K_{los}(t)$ = The loss costs at time *t* (year *t*)

$K_{fr}(t)$ = The fault repair costs at time *t* (year *t*)

$K_{mai}(t)$ = The maintenance costs at time *t* (year *t*)

T = Planned lifetime

The lifetime costs are calculated as a sum of each years present worth values. The present worth value can be calculated following the equation 6.2 below.

$$C_{present} = C_t \cdot \frac{1}{(1 + p/100)^t} \tag{6.2}$$

In the equation:

C_t = The sum of money at time t

p = The annual interest rate

t = The year t in future

A simple way to derive the investment costs for the whole observation period is to calculate annuity factor. The annuity factor is calculated by the following equation 6.3. The annuity factor notices the observation period and interest rate.

$$\varepsilon = \frac{p/100}{1 - \frac{1}{(1 + p/100)^t}} \tag{6.3}$$

In the equation:

p = Interest rate

t = The year observation period

The lifetime of the network used in calculations is 40 years, though the real lifetime of the traditional distribution network and its components is actually somewhere between 50-60 years. On the other hand the lifetime of the DC-components is nowhere near 40 years. Even in the best possible circumstances the lifetime of the diode or thyristor converters is only about 20 years and the lifetime of IGBT converters is only half of what is the lifetime of diode converters. In practise this means that the power electronic-components of the LVDC-links need to be replaced two or three times during the lifetime of a traditional distribution network. The extra investment of the power-electronics at around 20 years is excluded from the lifetime cost calculations because the investment cost of converters is not known and there wasn't available even any sophisticated guesses about the costs. In the calculations the increase in power consumption is assumed to be zero to make the calculations simpler.

6.1 Comparison of the lifetime costs

When estimating the real lifetime costs of the network the interest rate needs to be noticed. The simplest way of doing that is to use the equation 6.2 to calculate the present worth values of each year of the observation period and sum them. In this study the increase of loading is assumed to be zero. This assumption is made to simplify the calculations.

The interest rate used in calculations in this study is 4 %. In the following Tables 6.3 and 6.4 are presented the lifetime costs of both MV feeders when the 4 % interest rate is noticed in the calculations. First on Table 6.3 are the lifetime costs of the MV feeder 11 KST_KIVIJÄRVI.

Table 6.1. *The lifetime costs of MV feeder 11 KST_KIVIJÄRVI with 4% interest rate.*

Type	Branches Cabled	Branches LVDC
Investment	561 603 €	401 444 € *
Losses	21 240 €	107 194 €
Maintenance	7 149 €	21 546€ **
Fault repair	69 170 € ***	151 282 € ***
Sum	659 163 €	681 467 €

* Excluding power electronics investment costs
** Excluding maintenance material costs
*** Excluding fault repair material costs

The lifetime costs presented in Table 6.1 are illustrated in figure 6.1 in a form of column chart. The columns present the possible replacement options for the branch lines.

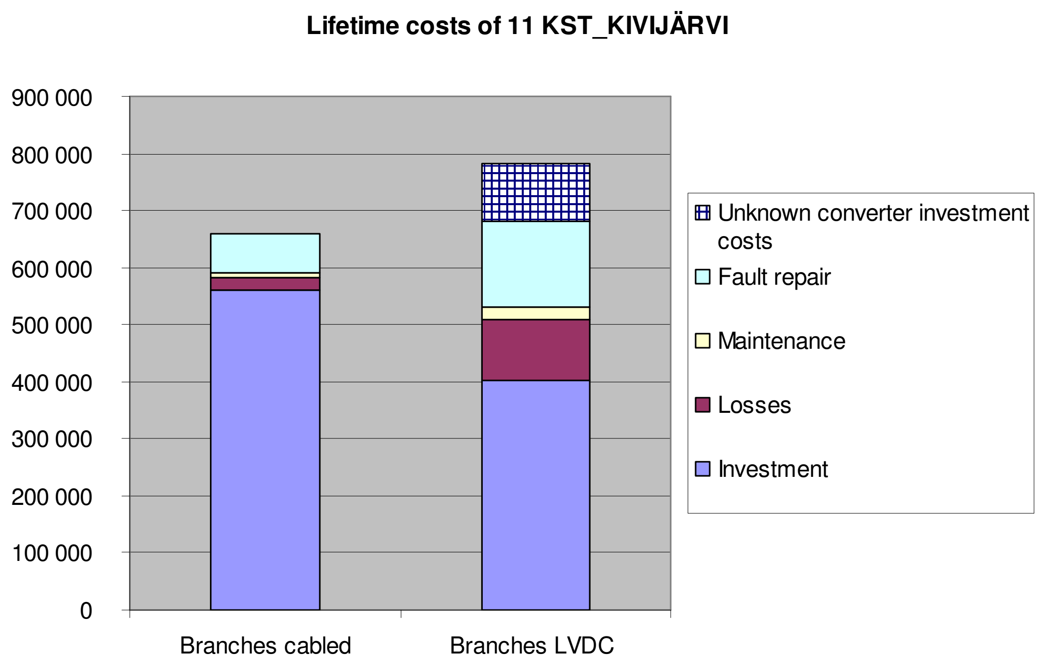

Figure 6.1. *Lifetime costs of MV feeder 11 KST_KIVIJÄRVI when interest rate is 4 %.*

The lifetime costs calculated with 4 % interest rate of MV feeder 03 LSJ_MIEKKO are presented in Table 6.2.

Table 6.2. *The Lifetime costs of MV feeder 03 LSJ_MIEKKO when interest rate is 4 %.*

Type	Branches Cabled	Branches LVDC
Investment	493 858 €	407 317 € *
Losses	85 218 €	125 209 €
Maintenance	7 149 €	21 566 € **
Fault repair	62 761 € ***	124 958 € ***
Sum	**648 986 €**	**679 050 €**

* Excluding power electronics investment costs
** Excluding maintenance material costs
*** Excluding fault repair material costs

The lifetime costs presented in Table 6.2 are illustrated in figure 6.2 in a form of column chart. The columns present the possible replacement options for the branch lines.

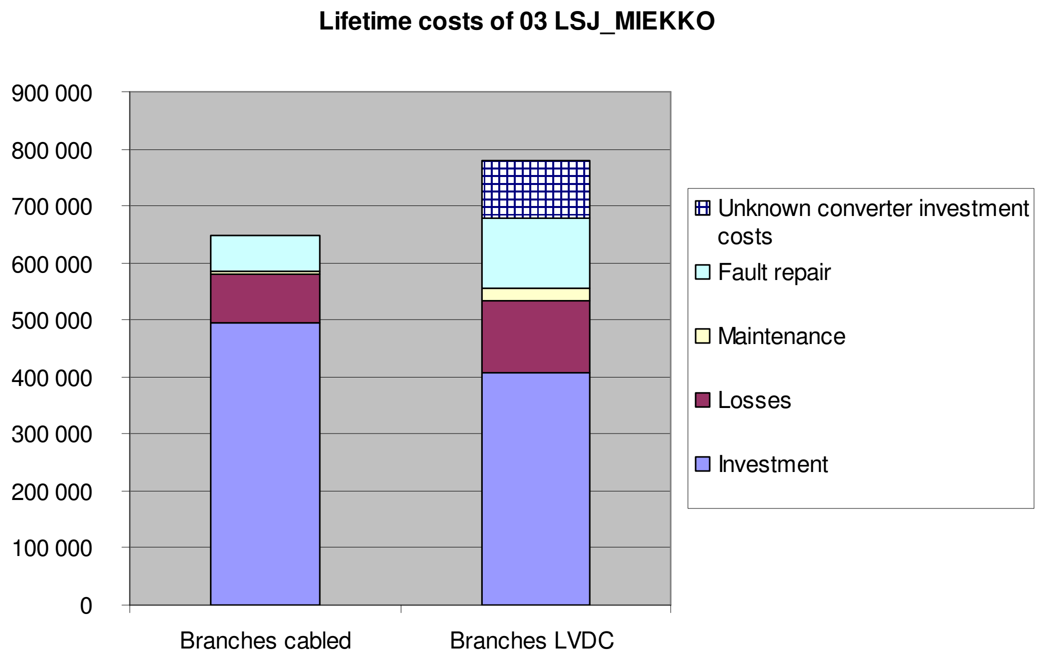

Figure 6.2. *Lifetime costs of MV feeder 03 LSJ_MIEKKO when interest rate is 4 %.*

As the Tables and the figures show the investment cost of each replacement solution is the biggest expense source of the lifetime costs. This means that it has large impact on the outcome.

When, comparing only the investment costs of the LVDC and cabling of the branches the difference between them is about 150 000 € on 11 KST_KIVIJÄRVI and 85 000€ on 03 LSJ_MIEKKO and the average of the two MV feeders is about 120 000 €. If only the investment costs are considered, the investment price of the power electronics could be about 120 000 € per MV feeder and about 9000 € per replaceable branch line. Depending on the calculation method and MV feeder the loss cost or the fault repair costs are the second or third biggest cause of expenses.

The loss, fault repair and maintenance costs are all bigger for LVDC-links than for cabling. The reason for the loss costs to be bigger is simply because the efficiency ratio of the LVDC-link is not as good as the efficiency ratio of the cabled branch line. The worse efficiency ratio results from the triple amount of network components comparing with the traditional structure of the distribution network. The traditional branch line consists of cable and one distribution transformer while the LVDC-links consist of distribution transformer and galvanic isolation transformers, rectifier and inverter and the cable. That is three lossy components more than in the traditional branch line.

The bigger fault repair costs explanation is also the larger number of fault inclined components. The fault rate of converters is also much higher than the fault rate of 20 kV cable or the distribution transformers. Even though the LVDC-links form their own protection area which means the fault resulted in LVDC-links does not result in a fault elsewhere in the network, the fault rate of the whole MV feeder is still somewhat higher than the fault rate of MV feeder when the branch lines are cabled. The fault rate correlates directly with the fault costs. The higher the fault rate is the bigger is the cost of fault repairs.

The maintenance costs are the smallest expense group among the lifetime costs. In practise 20 kV cabled branch lines maintenance costs consist mostly of the inspection and maintenance cost of the distribution transformers. In LVDC links the maintenance costs will consist mostly of the small maintenance work and material that needs to be done every fifth year to the converters. On LVDC-links, the transformers' time based inspections can be left out because the converters will be equipped with good data connections to the SCADA system and some fault diagnostic software. The maintenance costs of LVDC-links are three times bigger than the maintenance costs of cabled branch lines but they are still less than the maintenance costs of the overhead lines. Overall the maintenance costs over the lifetime are quite insignificant comparing to the other cost sources; they form only 1-5 % of the total lifetime costs.

The interruption-costs needs to be taken into consideration as a part of the lifetime costs when deciding about the implementation of the new technology. In the following Tables 6.3 and 6.4 and Figures 6.3 and 6.4 are presented the effect of interruption-costs to the total lifetime costs. First in Table 6.3 are the total lifetime costs of MV feeder 11 KST_KIVIJÄRVI with the interruption costs and when the 4 % interest rate is noticed.

Table 6.3. *The total lifetime costs of MV feeder 11 KST_KIVIJÄRVI with interruption-costs when the 4 % interest rate is noticed.*

Type	**Branches Cabled**	**Branches LVDC**
Investment	561 603 €	401 444 € *
Losses	21 240 €	107 194 €
Maintenance	7 149 €	21 546 € **
Fault repair + Interruption	489 181 € ***	635 480 € ***
Sum	**1 074 672 €**	**1 157 661 €**

* Excluding power electronics investment costs

** Excluding maintenance material costs

*** Excluding fault repair material costs

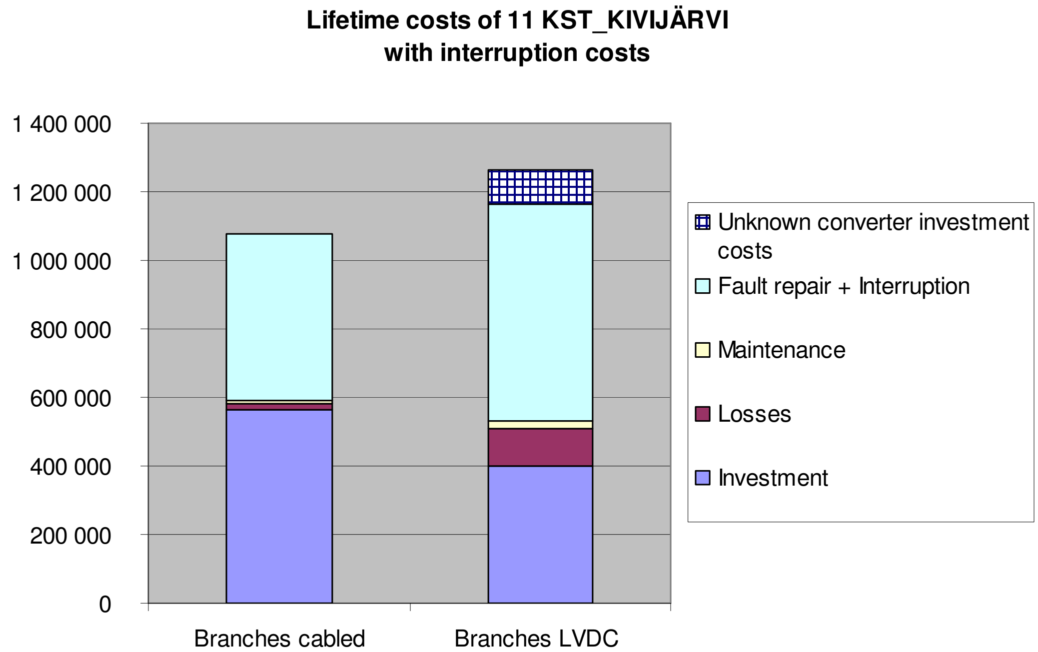

Figure 6.3. *The total lifetime costs of MV feeder 11 KST_KIVIJÄRVI with interruption-costs when the 4 % interest rate is noticed.*

The total lifetime costs with interruption-costs of MV feeder 03 LSJ_MIEKKO are presented in Table 6.4 below. The 4 % interest rate is noticed in the Table 6.4 costs.

Table 6.4. *The total lifetime costs of MV feeder 03 LSJ_MIEKKO with interruption-costs when the 4 % interest rate is noticed.*

Type	Branches Cabled	Branches LVDC
Investment	493 858 €	407 317 € *
Losses	85 218 €	125 209 €
Maintenance	7 149 €	21 566 € **
Fault repair + Interruption	1 243 721 € ***	1 496 626 € ***
Sum	**1 829 803 €**	**2 050 749 €**

* Excluding power electronics investment costs

** Excluding maintenance material costs

*** Excluding fault repair material costs

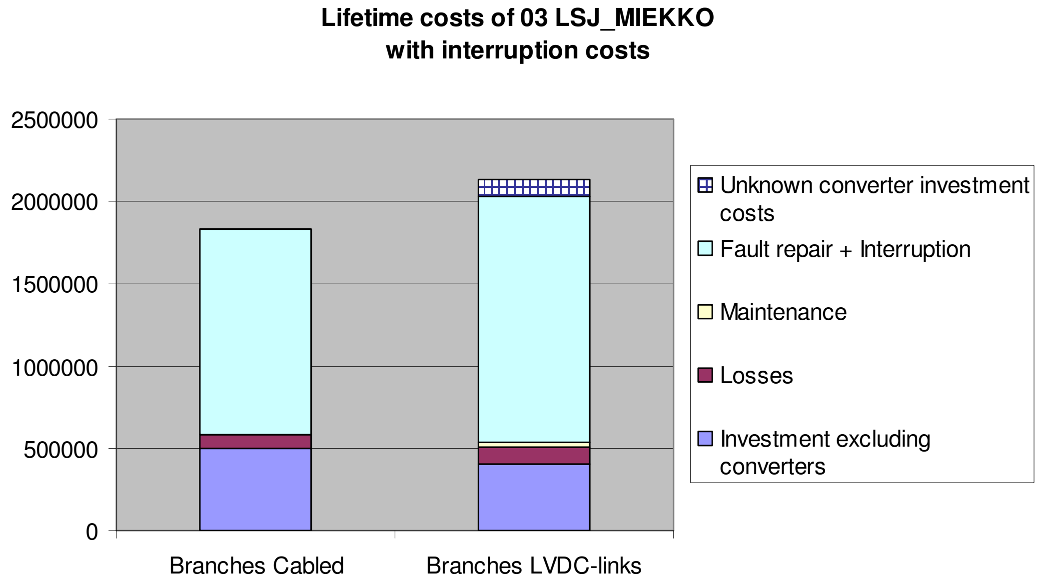

Figure 6.4. *The total lifetime costs of MV feeder 03 LSJ_MIEKKO with interruption-costs when the 4 % interest rate is noticed.*

Like Tables 6.3 and 6.4 and figures 6.3 and 6.4 can be seen the interruption costs play a significant role in the whole lifetime costs on both MV-feeders. The share of interruption and fault repair cost is roughly half of the total lifetime costs on both MV feeders. The difference between interruption-costs of LVDC and cabling is about 150 000 € during the whole lifetime of the MV-feeders. The huge difference between the investment costs and the interruption costs is explained by the fact that the investment costs are calculated only for 13 branch line where as the interruption costs are calculated for the whole MV feeder.

When comparing the lifetime costs with each other, the cabling of the branch lines is the best solution in long run even though the investment costs are significantly higher than the LVDC-links. The LVDC-links need to develop a whole lot more to become a commonly used technology in the distribution networks. The losses of the LVDC-links form mostly on the converters and transformers so the efficiency of the converters needs to be at least the same as the present distribution transformers or even higher because of the bigger number of needed components. If the efficiency ratio of the LVDC-links transformers and converters was 0,98, it would decrease the loss costs on both MV-feeders roughly by half.

The reliability of the converters needs to develop also or the reliability studies of the converters should be more specific and done in more similar circumstances to the distribution network environment than the reliability data collected from the industrial use of converters. As already mentioned the number of faults correlate directly to the fault repair costs, so the only way to reduce them is to increase the MTBF value of the converters. Even the improvement from approximately MTBF 3 years to 8 years would be enough. Only with 5 years improvement in MTBF value, the fault repair work costs of LVDC-links would be less on MV feeder 03 LSJ_MIEKKO and almost the same on the other MV feeder.

The higher maintenance costs of LVDC-links than cabled branch lines are almost unavoidable unless the power electronic components develop somewhat and the lifetimes of ELKOs, fans and air filters increase with several years. With the present components and technology the higher maintenance costs of LVDC-links just needs to be accepted.

The biggest source of expense is the investment cost which is somewhat smaller for the LVDC-links than the cabling investment, but still it is too high. The double number of transformers on LVDC-links forms almost 30 % of the total investment cost and on cabled branch lines the share of transformers is only about 10 %. The savings on investment costs would be 15 % on LVDC-links if the galvanic isolation transformer were left out. The investment cost of converters is not calculated in the total investment costs because there was not available any reliable estimates for it.

If all the improvements suggested in the paragraphs before were done to the LVDC-links, it would become a very interesting option to the cabling of the branch lines when looking from a network company's point of view. With the suggested improvements the total lifetime costs of LVDC-links would be less than cabling's lifetime costs. Even with the required replacement investment of the converters after 20 years the LVDC-links lifetime costs would be less.

In the following Tables 6.5 and 6.6 are presented the total lifetime costs for both MV feeders when the suggested improvements are taken into account also the 4 % interest rate is noticed. The suggested improvements:

- Efficiency ratio of the LVDC links: 0,98
- MTBF of converters: 8 years
- The number of transformers halved

The replacement cost of the converters around year 20 of the observation period is still left out due to the lack of knowledge about the prices of the converters.

Table 6.5. *The lifetime costs of MV feeder 11 KST_KIVIJÄRVI when the interest rate is 4 % and the improvements are done on LVDC-links.*

Type	Branches cabled	LVDC
Investment	561 603 €	346 748 € *
Losses	21 240 €	40 250 €
Maintenance	7 149 €	21 546 € **
Fault repair	69 170 € ***	97 677 € ***
Sum	**659 163 €**	**506 222 €**

* Excluding power electronics investment costs

** Excluding maintenance material costs

*** Excluding fault repair material costs

The costs presented in Table 6.5 are in illustrated in column chart form in figure 6.5. In the column chart below are only illustrated the lifetime costs of cabling of the branch lines and LVDC-links.

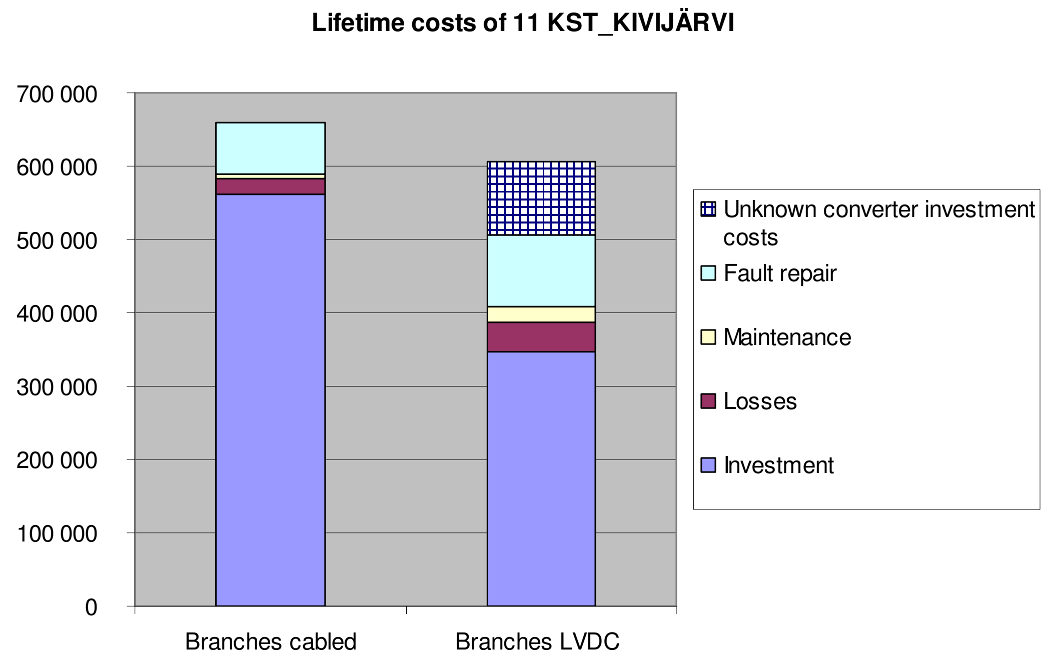

Figure 6.5. *The lifetime costs of MV feeder 11 KST_KIVIJÄRVI when the interest rate is 4 % and the improvements are done on LVDC-links.*

The total lifetime costs of MV feeder 03 LSJ_MIEKKO when all the improvements are done to the LVDC-links and the interest rate of 4 % is noticed.

Table 6.6. *The lifetime costs of MV feeder 03 LSJ_MIEKKO when the interest rate is 4 % and the improvements are done on LVDC-links.*

Type	**Branches cabled**	**Branches LVDC**
Investment	493 858 €	348 114 € *
Losses	85 218 €	66 388 €
Maintenance	7 149 €	21 566 € **
Fault repair	62 761 € ***	71 353 € ***
Sum	**648 986 €**	**507 422 €**

* Excluding power electronics investment costs
** Excluding maintenance material costs
*** Excluding fault repair material costs

The lifetime costs presented in Table 6.6 are illustrated as column chart in figure 6.6.

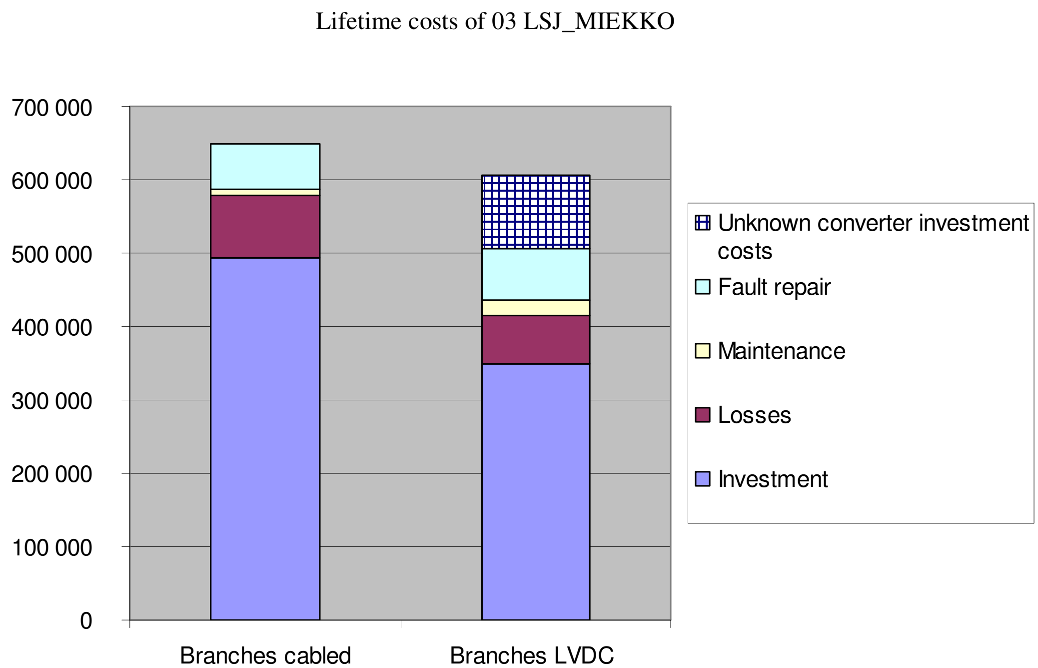

Figure 6.6. *The lifetime costs of MV feeder 03 LSJ_MIEKKO when the interest rate is 4 % and the improvements are done on LVDC-links.*

Like the tables and figures above show the expense difference in lifetime costs of LVDC-links and cabled branch lines is 152 941 € on the MV feeder 11 KST_KIVIJRÄVI and 145 744 € on the 03 LSJ_MIEKKO. This means that the investment and replacement cost of converters, the fault repair material costs and maintenance material costs of the LVDC-links during the whole 40 years lifetime needs to be less than the expense difference and then the whole lifetime costs of LVDC links would be less than the cabled branch lines.

7 CONCLUSIONS

Like mentioned before, there are still many uncertain things when applying LVDC-systems as a part of distribution networks. The biggest issue is the reliability of the converters in distribution networks. There they are very exposed to different weather phenomena. The LVDC-systems has a small positive impact on the reliability of the whole MV feeder as they form their own protection area. In practise this means that if a fault occurs in the network after the rectifier it will not affect anywhere else in the MV feeder. The other quite large issue is what will be the true efficiency ratio of the LVDC-systems as a part of the distribution network. The efficiency ratio has huge impact on what are the true loss costs of the LVDC-systems.

The LVDC-systems have some great advantages when compared with the 20 kV cabling. These advantages are the most related to the quality of distribution. With LVDC-systems it is possible to remove all the quick autoreclosures from the customers. The quick changes in voltage can also be removed and the range of change in voltage can be kept in the very low level and the difference between phase voltages can be kept near zero as well. The frequency of the supply can be kept very steadily in 50 Hz with the converters.

The LVDC-systems enable the connection of DG and energy storages to the distribution networks much more easily than 20 kV cabled AC networks. This opportunity is a good one when the smart grids are going to generalize. The other thing on LVDC-systems that supports the idea of smart grids is the possibility to use it as an island network when there is DG or energy storages attached to it.

Before LVDC-systems are going to become general, all the issues mentioned in the text earlier needs to be solved. Although it seems at the moment that LVDC-systems are still more expensive to invest in than 20 kV cabled branch lines, the prices of power electronics are constantly decreasing. Also the energy efficiency of the power electronic equipment keeps improving. The most challenging thing to improve on the LVDC-systems is how to solve the galvanic isolation between customers and the feeding network without the galvanic isolation transformer. Also there is the open question how much the LVDC-systems are going to need maintenance during their lifetime and what will be the actual lifetime of the converters in distribution network usage. At the moment, the expected lifetime of diode and thyristor converters is 15-20 years and for IGBT converters it is only 5-10 years where as the lifetime of 20 kV cabled network is 40 years or even more.

The improvement for the LVDC system does not need to be very big so it will become more affordable to invest in than the 20 kV cabling in the branch lines. Only with the following improvements

- Efficiency ratio of the LVDC links: 0,98
- MTBF of converters: 8 years
- The number of transformers halved,

the lifetime costs of the LVDC-links for both MV feeders 11 KST_KIVIJÄRVI and 03 LSJ_MIEKO will be less than for 20 kV cabling. With these improvements, the power electronic converters and components' investment costs can be done twice during the 40-year observation-period and it will be still less than the lifetime costs of the 20 kV cabling.

As an outcome of the calculations presented in the previous chapters can be stated that the time for LVDC systems is not quite yet. As the improvement that needs to be done to make the LVDC systems beneficial are not impossible to solve the time for this technology will be in somewhere in the near future.

REFERENCES

Energy Market Authorities. 2012. The unit prices.

IEC 60644-1. 2002. Insulation coordination for equipment within low-voltage systems – Part 1: Principles, requirements and tests. Edition 1:1992 consolidated with amendments 1:2000 and 2:2002. International Electrotechnical Commission, Geneve, Sveitsi.

Hakala Tomi. 2012. The utilization potential of LVDC distribution in the LNI distribution network. Bachelor’s Thesis. Tampere University of Technology. 34 p.

Kaipia Tero. 2011. Power Electronics in Electricity Distribution and LVDC – proof of concepts. Presentation in Cleen Summit 7.4.2011

Kaipia, T., Salonen, P., Lassila, J., Partanen, J. 2006. Possibilities of low voltage DC distribution system. NORDAC conference 08/2006, Stockholm.

Komsi, Reijo. 2011a. Power Electronics in Electricity Distribution and LVDC – proof of concepts. Presentation in Cleen Summit 7.4.2011

Komsi, Reijo. 2011b. Follow-up report of the ABB ACS800 island converter.

Lakervi, E., Holmes, E.J. 1995. Electricity distribution network design. London. Peter Peregrinus. 325 p.

Lakervi, E., Partanen, J., 2009. Sähkönjakelutekniikka. Helsinki. Otatieto Helsinki University Press, 2009 Hakapaino

Lappeenranta University of Technology. 2007. Tasasähköjakelujärjestelmän toiminnalliset kriteerit ja sähköturvallisuustarkastelu. Report. Lappeenranta. Department of Electricity engineering. 77 p.

Lappeenranta University of Technology. 2010. Tehoelektroniikka sähkönjakelussa – Pienjännitteinen tasasähkönjakelu. Final report. Lappeenranta. Department of Electricity engineering. 170 p.

Lähdeaho, Tommi. 2011. Manager of Electrical plannig, LNI Verkko Oy. Tampere. Interview 13.08.2011.

Marquet, D., Foucault, O., Acheen, J., Turc, J.F., Szpek, M., Brunarie, J. 2011. Pre roll-out field test of 400 VDC power supply: The new alliance of Edison and Tesla towards energy efficiency. Telecommunications Energy Conference (INTELEC), 2011 IEEE 33rd International, Amsterdam, Netherlands. 9.-13.10.2011

Mohan, N., Undeland, T., Robbins, W., 2003. Power Electronics, Converters, Applications and Design. John Wiley & Sons, 2003. 802 p.

Mäkinen, Antti. 2010. Sähköverkon häiriöt ja sähkön laatu. Opintomoniste. Tampere. Department of Electricity Engineering. 55 p.

Niiranen, J., Komsi, R., Routimo, M., Lähdeaho T., Antila S. 2010. Experiences from a Back-to-Back Converter fed Village Microgrid. Innovative Smart Grid Technologies Conference Europe (ISGT Europe), Gothenburg, 11.-13.10.2010.

Partanen, J., Pyrhönen, J., Silventoinen, P., Niemelä, M., Lindh, T., Kaipia, T., Salonen, P., Nuutinen, P., Peltoniemi, P., Lassila, J. 2008. Tehoelektroniikka sähkönjakelussa. Report of Part 1/2. Lappeenranta University of Technology, Department of Electricity Engineering. 96 p., 12 appendixes.

Rekola, Jenni. 2009. Kolmitasoiset suuntaajat tasasähkönjakelussa. Master's Thesis. Tampere University of Technology. 82 p.

Rodriguez J., Jih-Sheng Lai, Fang Zheng Peng. 2002. Multilevel Invert-ers: A Survey of Topologies, Controls and Applications. IEEE Transactions on Industrial Electronics. Vol. 49, Issue 4. Aug 2002. p. 724-738.

Salonen, Pasi. 2006. Exploitation possibilities of DC in electricity distribution. Master's thesis. Lappeenranta University of Technology. 86 p., 5 appendixes.

SFS-EN 50160. 2008. Yleisen jakeluverkon jakelujännitteen ominaisuudet. Helsinki, Suomen Standardoimisliitto SFS ry.

SFS-6000-1. 2007. Pienjännitesähköasennukset. Helsinki, Suomen Standardoimisliitto SFS ry. 58p.

Tekla. 2011. Tekla NIS – Luotettavuuslaskenta ja Verkko-omaisuuden hallinta. Toiminnallinen määrittely. [Unpublished material]. LNI Verkko Oy.

Vornanen Tuomo. 2009. PSCAD simulation of electricity distribution networks with power electronics. Master's Thesis. Tampere University of Technology. 86 p.