**LAPPEENRANTA UNIVERSITY OF TECHNOLOGY**
**LUT School of Technology**
Degree Program in Electrical Engineering

*Esa Äärynen*

# STRATEGIC PLANNING OF MAJOR DISTURBANCE PROOF NETWORK

Examiners: Professor Jarmo Partanen
Associate Professor Jukka Lassila

Supervisor: M.Sc.(Tech) Jarmo Saarinen

## ABSTRACT

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**Strategic planning of major disturbance proof network**

2014

Master's thesis.

64 p., 13 figures, 10 tables, 2 appendixes

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In the 2000's Finland suffered from storms that caused long outages in electricity distribution, longest up to two weeks. These major disturbances increased the importance of supply security. In 2013 new Electricity Market Act was announced. It defined maximum duration for outages, 6 h for city plan areas and 36 h for other areas.

The aim for this work is to determine required major disturbance proof level for a study area and find tools for prioritizing overhead lines for cabling renovation to improve supply security. Three prioritization methods were chosen to be studied: A: prioritization line sections by customer outage costs they cause, B: maximizing customers major disturbance proof network and C: minimizing excavation costs in medium voltage network.

Profitability calculations showed that prioritization method A was the most profitable and C had the weakest profitability. The prioritization method C drove renovation into unreasonable locations in the study area in reliability point of view. Therefore universal rule prioritization methods couldn't be made from the prioritization methods. This led to the conclusion that every renewing area need to be evaluated in a case by case basis.

**TIIVISTELMÄ**

Lappeenrannan teknillinen yliopisto
Teknillinen tiedekunta
Sähkötekniikan koulutusohjelma

Esa Äärynen

**Suurhäiriövarman sähkönjakeluverkon strateginen suunnittelu**

2014

Diplomityö

64 p., 13 kuvaa, 10 taulukkoa, 2 liitettä

Tarkastajat: professori Jarmo Partanen.
Tutkijaopettaja Jukka Lassila

Työn ohjaaja: DI Jarmo Saarinen

Suuret myrskyt ovat koetelleet Suomea ja sähkön jakeluverkojen toimitusvarmuutta 2000-luvulla. Myrskyt aiheuttivat pitkä, jopa kahden viikon pituisia sähkökatkoja. Tämä nosti toimitusvarmuuden vaatimukset uudelle tasolle. Edelliset syyt johtivat uuteen sähkömarkkinalakiin, jossa määriteltiin asemakaava-alueelle 6 h ja muualle 36 h suurimmiksi sallituiksi keskeytysajoiksi, koskien kaikkia asiakkaita vuoteen 2029 mennessä.

Työn tavoitteena on määrittää vaadittava suurhäiriövarmuus taso tutkittavalle alueelle sekä löytää uusia työkaluja toimitusvarmuusinvestointien priorisoinnille. Toimitusvarmuus-investointien kohdistamiselle valittiin kolme priorisointi menetelmää. A: johto-osien priorisointi niiden aiheuttaman keskeytyskustannuksen perusteella, B: suurhäiriövarman verkon piirissä olevien asiakkaiden maksimointi sekä C: kaivukustannusten minimointi.

Kannattavuuslaskennan perusteella menetelmä A oli kannattavin ja C vähiten kannattava menetelmä. C:n priorisointi menetelmä johti tutkimusalueella luotettavuuden sekä käyttävyyden kannalta kannattamattomiin saneeraus kohteisiin. Tämän vuoksi tuloksia ei voi pitää yleispätevinä ja priorisointimenetelmien kannattavuus on arvioitava tapauskohtaisesti.

## PREFACE

This work was made for Caruna oy and it deals with modern-day challenges in developing electricity distribution network. I want to thank my supervisor Jarmo Saarinen for allowing me to make my master's thesis and guiding me on the way. A great thanks also to my colleagues who gave me valuable guidance.

A special thanks goes to my family and parents. I appreciate all the support you gave me during my studies.

My best friends also deserve gratitude for making my study times awesome and unforgettable.

Espoo 20.11.2014

Esa Äärynen

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# TERMS AND DEFINITIONS

## Symbols

| | |
|---|---|
| $Cd$ | Average cost of liability |
| $Ce$ | Reasonable return on equity |
| $Ct$ | Annual cash flow |
| $D$ | Amount of liability |
| $DP$ | Premium for lack of liquidity |
| $E$ | Amount of equity |
| $l$ | Length |
| $N$ | Number |
| $r$ | Reasonable rate of return |
| $Rr$ | Risk-free interest rate |
| $t$ | Time |
| $T$ | Lifetime |
| $\beta$ | Beta |
| $\varepsilon$ | Annuity |
| $\lambda$ | Fault frequency |
| $\Delta$ | Delta |

## Abbreviations

| | |
|---|---|
| *ATOTEX* | Allowed total operational expenditure |
| *CAIDI* | Customer Average Interruption Duration Index |
| *COC* | Customer outage costs |
| *DMS* | Distribution Management System |
| *DSO* | Distribution System Operator |
| *EMA* | Electricity Market Authority |
| *LV* | Low Voltage |
| *MDPR* | Major Disturbance Proof Rate |
| *MV* | Medium Voltage |

| | |
|---|---|
| *NIS* | Network Information System |
| *NPV* | Net present value |
| *RNA* | Reliability based Network Analysis |
| *RAV* | Regulated asset value |
| *RRC* | Reasonable return on capital |
| *RV* | Repurchase value |
| *SAIDI* | System Average Interruption Duration Index |
| *SAIFI* | System Average Interruption Frequency Index |
| *TOTEX* | Total operational expenditure |
| *TSA* | Thematic Spatial Analysis |
| *WACC* | Weighted Average Cost of Capital |

# 1. INTRODUCTION

Electricity distribution networks in Finland are mostly constructed in the rural areas between 60's and 90's. At that time electricity distribution networks were mainly built as overhead lines in forest. Average lifetime being from 40 to 60 years there is a great need for renovation. In the beginning of 2000's normal state reliability became significant driver for renovation investments. Nowadays supply security has become an important factor on electricity distribution network development.

In the 2000's there were a lot of storms in Finland that caused major disturbances to electricity distribution networks. Storms like Tapani and Hannu in 2011 caused outages for hundreds of thousands of customers. Longest outages lasted over two weeks. After that the Ministry of Employment and the Economy started a statement for improving supply security of electricity distribution networks.

Due the statement, changes was made in the Electricity Market Act. These changes consider maximum outage times and customer compensation payments. More important maximum outage times for one continuous electricity distribution interruption were defined to be six hours for city plan areas and 36 hours for rural areas. DSOs need to fulfill these maximum outage limits so that 50 % of customers are in scope of the outage limits in year 2020, 75 % in 2024 and 100 5 of customers in 2028.

For city plan areas the outage limit in practice means full scale cabling. For rural areas the 36 h outage limit gives more opportunities on network development. Targets set in the electricity market act creates a very tight schedule of 15 years for investments to develop network with improved supply security. This generates massive financial pressure for the DSOs and at the same time causes premature reinvestments on electricity distribution network.

This master's thesis is made on behalf of Caruna Oy. Caruna is the largest distribution system operator from 81 DSOs in Finland. Caruna was founded in the spring of 2014 before that if was a part of the Fortum group. Caruna holds 20 % market share of Finland's

local electricity distribution with 640 000 customers and 79 000 kilometers long network in South, Southwest and Western Finland as well as Joensuu, Koillismaa and Satakunta.

Electricity market act takes a stand on outage times in a major disturbance. There are two main ways to limit outage times in a major disturbance. These are improving fault fixing organization and renewing distribution network with weather proof network techniques. This work focuses on studying effects of network renovation with underground cables in medium voltage network.

Carunas network comprises largely from rural areas. This means that Caruna has a lot of network that need to fulfill the 36 hour. The new electricity market act gives DSOs the freedom to decide how they will develop their network to meet the outage limits. Therefore analysis need to be made concerning present state of the network and the level of supply security that correspond to outage limits in the electricity market act. Other important task is to determine most suitable locations for reinvestments on electricity distribution network.

In this work the study of supply security and effects of large scale cabling are located in Satakunta. The study area represents typical environment for Carunas network. The aim of this work is to determine needed level of supply security in the study area and to create tools for network reinvestment prioritization. This work focuses on supply security and financial effects of network investments. Therefore technical approach to network investments is left to minimum.

The level of supply security can be described with the rate of major disturbance proof network. In this work the needed major disturbance rate is determined from information gathered from Tapani storm. The needed major disturbance proof rate is determined for both MV and LV networks. Study of different prioritization methods for renovation location focuses on medium voltage network. The impacts on network and reliability are compared between different prioritization methods.

Network renovations are calculated as an onetime investment. Differences in investment profitability and effects to allowed revenue between prioritization methods are studied using same principles that are used in the regulation model. This way effects of regulation can be taken into account.

# 2. ELECTRICITY MARKET ACT

Our society is changing all the time to be more and more dependent on electricity. Long outages on electricity supply can be very harmful for many households and businesses. Therefore distribution system operators have to develop their grid to match their customer requirements on distribution reliability and supply security. Because distribution system operators work on a monopoly position on their own area, legislation needs to be updated so that DSOs will continue to improve and develop their networks.

Resent storms for example Tapani (winter 2011), Asta (summer 2010) and Veera (summer 2010) caused major disturbances that lasted for hundreds of hours, have raised governments interest in the supply security. In August of 2013 electricity market act was updated. The update concerned supply security, maximum allowed outage times and customer compensation payments. This chapter holds information about the new electricity market act and its impacts to electricity distribution business.

## 2.1 Allowed interruptions

In 2012 Finnish authorities were in a situation where they decided that something needs to be done concerning legislation and supply security. Therefore the new Finnish Electricity market act has requirements for maximal duration of outages in city plan and rural areas. In city plan areas maximum duration for an interruption is six hours and in rural areas 36 hours. (Finnish Electricity Market Act 588/2013)

There is a 15-year transition period to fulfill electricity market acts requirements. DSOs have until the end of 2028 to improve supply security on their distribution systems to meet time limits that the new electricity market act sets. There are two steps in the transition period before end of the year 2028. These steps contain following days and targets. (Finnish Electricity Market Act 588/2013)

31.12.2019: Requirements for maximum interruption durations of 6 and 36 hours need to be fulfilled for 50 % of customers.

31.12.2023: Requirements for maximum interruption durations of 6 and 36 hours need to be fulfilled for 75 % of customers.

31.12.2028: Requirements for maximum interruption durations of 6 and 36 hours need to be fulfilled for 100 % of customers. (Finnish Electricity Market Act 588/2013)

Finnish Energy Market Authority (EMA) may grand extra time for DSOs to reach the required supply security limits for 75 % and 100%. To get extra time DSOs development actions have to involve substantial amounts of underground cabling at both MV and LV level. For the extra time also a great amount of the renovated network is not yet at the end of its techno-economic life time. The deadline of 75 % can be postponed to 31.12.2025 and deadline of 100% can be postponed to 31.12.2036. If DSOs need the postponement, they have to submit an application by 31.12.2017. Finnish Energy Market Authority evaluates and approves the application for postponement. (Finnish Electricity Market Act 588/2013)

Electricity Market Act also states that all DSOs have to prepare a development plan concerning their distribution network. The plan must contain actions that DSOs are going to make to their distribution network that improve reliability and leads to the required supply security level. The development plan must be updated once in every two years. First time to submit the development plan to the Finnish Electricity Market Authority (EMA) is at the end of June of 2014. (Finnish Electricity Market Act 588/2013)

### 2.2 Customer compensation payments

In Finland like in many other countries, customers are entitled to get compensation if there is a long continuous interruption in electricity supply. In Finland these compensations have been paid since 2003. Customer compensation also works as an incentive for the DSOs to improve reliability and supply security in their distribution network. (Finnish Electricity Market Act 386/1995)

In Finland these customer compensation payments have been divided to four levels. Minimal compensation came if interruption time in electricity supply was more than 12 hour but less than 24 hours and it enabled customer to have 10 % compensation from its

yearly fee. Next level justified for 25 % from yearly distribution fee, when interruption time was between 24 and 72 hours. Third level was 50 % from yearly distribution fee with interruption time between 72 and 120 hours. Customer could get 100 % compensation from its electricity distribution fee if the interruption lasted minimum of 120 hours. Customer compensation payments were set so that maximum compensation for one customer was 700 €. (Finnish Electricity Market Act 386/1995)

In the new Electricity Market Act (588/2013), two levels were added to previous compensation levels and maximum amount of customer compensation payments were raised. New customer compensation levels are 150 % of electricity distribution fee for interruption time between 192 and 288 hours and 200 % of electricity distribution fee when interruption time has been at least 288 hours. The maximum amount for customer compensation payment have been raised from 700 € to 2 000 €. (Finnish Electricity Market Act 588/2013)

There is a transition period also for the maximum amount of customer compensation payments. If an interruption, that enables customer to get compensation, occurs before 01.01.2016 the maximum compensation is 1 000 €. The other date in this transition period is 01.01.2018 and maximum compensation for interruptions before that date is 1 500 €. (Finnish Electricity Market Act 588/2013)

# 3. REGULATION

In Finland electricity distribution has been a regulated business since 1995. It is operated by distribution system operators (DSO). DSOs work monopolies inside their own distribution area. Due a monopoly position of DSOs don't have benefits that open competition would offer. Regulation ensures that customers are treated equally, DSOs operate effectively and electricity distribution tariffs stay reasonable. Regulation is operated by Finnish Electricity Market Authority. (Partanen et al. 2012)

Regulation methods were reformed at beginning of the year 2005. Regulation started to operate in four year periods, first one being at 2005-2007. Current regulation period is the third one. This work handles current regulation periods methodology. The regulatory has a great effect on how the investments that lead to major disturbance proof network should be done and allocated.

## 3.1 Regulation model

The economic regulation consist of many components. These components constitute the regulatory model that is used to control DSOs allowed revenue and distribution tariffs. Therefore the regulation model is very complex and it can be difficult to determinate final benefits of different investments. (EMA 2011)

Basically the regulatory model is used to calculate realized adjusted profit. If the actual revenue is higher than allowed revenue, it tells that the DSOs electricity distribution tariffs has been too high. Therefore they have to return the surplus revenue in the next regulatory period by lowering their tariffs. On the other hand, if actual revenue is less than realized adjusted profit, DSOs are allowed to collect that deficit in the next regulatory period.

In the current regulation model there are four main elements that effect the realized adjusted profit. These are efficiency benchmarking, quality bonus, allowed depreciations and reasonable return on capital. In addition to these, a new incentive, called the security of

supply incentive, has been taken into use due the new Electricity Market Act. (EMA 2011) The Finnish regulatory model for years 2012-2015 is presented in figure 3.1.

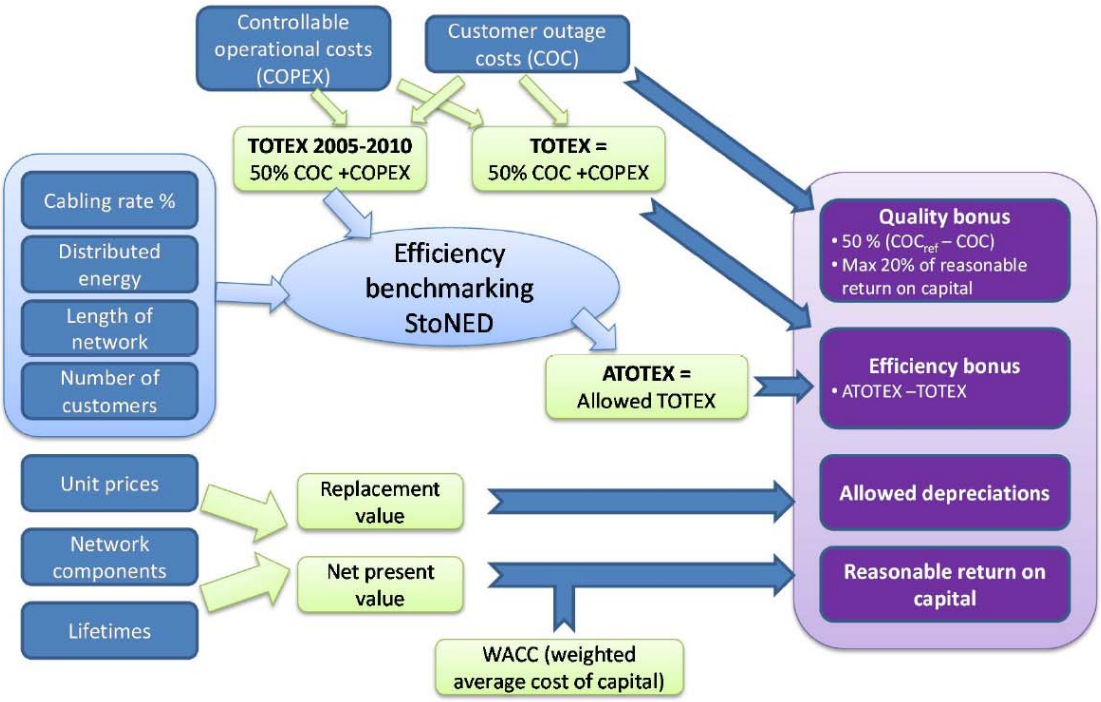


Figure 3.1 Outline of the Finnish regulatory model for years 2012 -2015. (Haakana 2013)

### *3.1.1 Quality bonus*

Customer outage costs (COC) are used to determinate DSOs quality bonuses. Quality bonus can also work as a sanction, depending on how DSOs COC have developed compared to the reference $COC_{ref}$ level. $COC_{ref}$ is a calculated average of COC from years 2005-2010, the same COC is also used as a parameter in efficiency benchmarking. However, will the DSO get quality bonus or sanction is dependent whether the outcome of $COC_{ref}$-COC is positive or negative. Positive value will lead to bonus and negative value to sanction. (sähkömarkkinapruju) (EMA 2011)

As customer outage costs also effect efficiency benchmarking, only 50% of COC is taken account into quality bonus. Quality bonus can only effect to DSOs profit for maximum 20 % of reasonable return on capital, that is defined later. The effect of quality bonus is described in Figure x at right top corner. (EMA 2011)

Customer outage cost consists of the amount of unannounced interruptions and their length, amounts of high-speed auto reclosing and delayed auto reclosing, announced work interruptions and its length. There is also prices for each of these interruptions. These prices are in the form of €/kW and €/kWh. So the average power of customers and energy that will not be supplied has a significant effect to the COC.

The COC is calculated with actual interruption data in the next way for year t in the value of year k. (EMA 2011)

$$COC_{t,k} = \frac{W_t}{8760}(c_u \cdot n_u + c_a \cdot n_a + c_u \cdot d_{ud} + c_a \cdot d_{ad} + c_{hr} \cdot n_{hr} + c_{dr} \cdot n_{dr}) \cdot \frac{CDI_{k-1}}{CDI_{2004}} \tag{3.1}$$

where $W_t$ = distributed energy at year t (kWh)

$c_u$ = cost of unannounced distribution interruption (€/kW)

$c_a$ = cost of announced distribution interruption (€/kW)

$c_{ud}$ = cost of unannounced distribution interruption duration (€/kWh)

$c_{ad}$ = cost of announced distribution interruption duration (€/kWh)

$c_{hr}$ = cost of high speed auto reclosing (€/kW)

$c_{dr}$ = cost of delayed auto reclosing (€/kW)

$CDI_{k-1}$ = consumer price index in year k-1

$CDI_{2004}$ = consumer price index in year 2004

The reference $COC_{ref}$ is fixed so that it corresponds to the energy that the DSOs have delivered to their customers on the year under review. This way it is possible to eliminate changes in the annual delivered energy, that is used to calculate average power. $COC_{ref}$ is calculated in the following way. (EMA 2011)

$$COC_{ref,k} = \frac{\sum_{t=2005}^{2010}\left[COC_{t,k}\cdot\left(\frac{W_k}{W_t}\right)\right]}{6} \tag{3.2}$$

In the quality incentive key figures regarding outages, for example number, duration and COC, are reported to the Energy Market Authority. Parameters for the calculation of customer outage cost are set by EMA. These parameters are prices for different kind of outages. The prices used for calculation of COC are presented in monetary value in table 3.1. (EMA 2011)

Table 3.1 The prices set by the Energy Market Authority for DSOs to calculate customer outage costs in electricity distribution. The prices are in 2005 monetary value. (EMA 2011)

| Unexpected outage | | Planned outage | | Time-delayed autorecloser | High-speed autorecloser |
|---|---|---|---|---|---|
| $h_{E,unexp}$ | $h_{W,unexp}$ | $h_{E,plann}$ | $h_{W,plann}$ | $h_{AJK}$ | $h_{PJK}$ |
| €/kWh | €/kW | €/kWh | €/kW | €/kW | €/kW |
| 11.0 | 1.1 | 6.8 | 0.5 | 1.1 | 0.55 |

### *3.1.2 Efficiency bonus*

EMA defines efficiency targets for the electricity distribution industry and for every DSO. The efficiency targets for distribution industry steers DSOs to improve efficiency by the common trend of the industry. This general efficiency target is 2,06 % per year for the current regulation period. The company-specific targets steers inefficient companies to improve their own efficiency. In the regulatory model efficiency benchmarking uses a StoNED-model (Stochastic Non-smooth Envelopment of Data) to determinate company specific efficiency requirement. Average $TOTEX_{05\text{-}10}$, network length, cabling rate, distributed energy and the amount of customers are taken into account in the efficiency requirement along with the general efficiency target. Efficiency requirement is used to calculate allowed total operational costs ATOTEX (EMA 2011)

Simplistically the company-specific efficiency targets are determined by comparing ATOTEX with total operational costs TOTEX. Operational costs consist of controllable costs like maintenance and 50 % of customer outage costs. (EMA 2011)

In this work, to simplify calculations, efficiency bonus is calculated the next way

$$\text{Efficiency bonus} = 0{,}5 \cdot \Delta COC + \Delta ATOTEX \tag{3.3}$$

where ΔCOC is change in customer outage costs

ΔATOTEX is change in allowed total operational costs, such as fault fixing and maintenance costs.

### *3.1.3 Straight line depreciations*

In the regulation model regulatory straight line depreciations are used as investment inducement for the DSOs. Intention for this is to get DSOs to develop their network and to invest sufficiently. The allowed depreciations are calculated as straight-line depreciations in the regulatory model. Repurchase value works as a basis for straight-line depreciations. Regulatory repurchase values for network components in can be seen in appendix X. These depreciations are calculated for every single network component the next way. (EMA 2011)

$$Depreciation = \frac{RV}{Lifetime} \tag{3.4}$$

Where $RV$ = Repurchase value.

As seen in the equation (3.4), the lifetime of network components plays also a great role in regulatory straight line depreciation. If the lifetime for a network component is long the regulatory straight line depreciations are smaller and vice versa. In the Finnish regulation the lifetimes of network components, for example overhead lines, cables and transformers vary between 25 - 50 years.

### *3.1.4 Reasonable return on capital*

In the Finnish regulatory model, a great deal of DSOs allowed revenue comes from reasonable return on capital (RRC). Reasonable return on capital is calculated in the model the method of Weighted Average Cost of Capital (WACC). Other factor that influences the RRC is regulated asset value (RAV). Net present value can be calculated in the regulation model by using age, lifetime and repurchase value of network in the flowing way. (EMA 2011)

$$RAV = \left(1 - \frac{Age}{Lifetime}\right) * RV, \tag{3.5}$$

Where $RV$ = Repurchase value.

WACC that is used in the regulatory model is calculated by using a fixed amount of equity 70 % and liability 30 % for the DSO. WACC calculation is shown in equation (3.6).(EMA 2011)

$$WACC = C_{\mathrm{E}} * \frac{E}{D+E} + C_{\mathrm{D}} * (1 - t) * \frac{D}{D+E}, \tag{3.6}$$

where $C_{\mathrm{E}}$ = reasonable return on equity

$C_{\mathrm{D}}$ = average cost of liability

$t$ = tax rate

$E$ = amount of equity

$D$ = amount of liability

Reasonable return on equity is determined by Capital Asset Pricing Model (CAP).

$$C_{\mathrm{E}} = R_{\mathrm{r}} + \beta_{\mathrm{E}}(R_{\mathrm{M}} - R_{\mathrm{r}}), \tag{3.7}$$

where $R_{\mathrm{r}}$ = risk-free interest rate

$\beta_{\mathrm{E}}$ = beta of equity

$R_{\mathrm{M}}$ = average return on markets

$R_M$-$R_r$ = risk premium of markets

Average cost of liability can be calculated as presented in equation (3.8).

$$C_D = R_r + DP \tag{3.8}$$

where $DP$ = Premium for lack of liquidity.

The regulatory model also determines parameters which are applied in the calculation of a reasonable rate of return. The parameters applied in calculation of reasonable rate of return are presented in table 3.2.

Table 3.2 The parameters used to calculate weighted average cost of capital (WACC) in the third regulatory period of the Finnish regulatory model. (EMA 2011)

| Parameter | Value to be applied (those subject corporation tax) | Value to be applied (others) |
|---|---|---|
| Real risk-free rate | Interest of 10-year Finnish government bond (average of May in the previous year) deducted by the inflation component | Interest of 10-year Finnish government bond (average of May in the previous year) deducted by the inflation component |
| Inflation component *(deducted from nominal risk-free rate)* | 1 % | 1 % |
| Beta of asset | 0,4 | 0,4 |
| Beta of equity | 0,527 | 0,571 |
| Market risk premium | 5,00 % | 5,00 % |
| Premium for lack of liquidity | 0,50 % | 0,50 % |
| Capital structure *(liability/equity)* | 30 / 70 | 30 / 70 |
| Tax rate | 24,50 % | 0 % |
| Cost of interest-bearing dept | real riskf-free rate + riskpremium of dept 1.0% | real riskf-free rate + riskpremium of dept 1.0% |

After WACC and regulatory asset value has been determined, reasonable return on network capital can be simply calculated by multiplying WACC and RAV. (EMA 2011)

$$RRC = WACC * RAV \tag{3.9}$$

As seen from equation (3.9), the net present value of network has a significant effect on RRC. By reinvesting on the oldest parts of their network, DSOs can decrease the age of their network and thereby increase the net present value. With greater net present value of electricity distribution network DSOs can collect more revenue. On the other hand premature reinvestments cause loss of RAV and revenue to the DSO.

### *3.1.5 Security of supply incentive*

Security of supply incentive is a new incentive that was taken into use due the new Electricity Market Act. This incentive takes into account early replacement investments and new maintenance, which means preventative measures to improve security of electricity supply. (EMA 2013)

The net present value of demolished network in early replacement investments due improving of the security of supply is taken into account in the calculation of the realized adjusted profit. Regulated asset value from early replacement investments that improve supply security will be accepted as a write-down when calculating realized adjusted profit. The write-down on regulated asset value is possible in case of 20 kV overhead lines, pole mounted secondary substations, disconnectors in overhead line network, disconnection substations and 0,4 kV overhead lines. The RAV-write-down value is calculated separately for each component. The write-down can be implemented only once for the demolition year of each component. The regulated asset value is calculated as shown in equation (3.5). (EMA 2013)

Costs of new maintenance/preventative actions taken into order to improve security of supply will be will be take into account when realized adjusted profit is calculated. Costs that are to be included into the security of supply incentive are

- improving the management of side forest treatment to a MV line corridor,

- costs of developing systems used to communicate with the authorities and customers and

- costs of maintaining systems used to communicate with the authorities and customers.

These costs will be taken into account in the efficiency bonus. In the efficiency bonus the previously mentioned costs will not be deducted when calculating the actual annual efficiency costs. (EMA 2013)

The effect of security of supply incentive can be calculated by summarizing NPV-write-down value and costs of new maintenance/preventative actions taken into order to improve supply security of supply. The sum is reduced from companies actual profit. During the third regulatory period for the years 2014 and 2015, the security of supply incentive will be applied for the regulation of reasonable pricing. (EMA 2013)

# 4. STRATEGIC PLANNING

Strategic planning is an important part of electricity distribution business. It determines guidelines for network planning and therefore has an significant impact on the electricity distribution business. In this work strategic planning focuses on supply security and renovation strategies. A target level for major disturbance proof networks is needed due the new electricity market act and the development plan it requires. After target level for major disturbance proof network is determined, it is important to find the best way how that target will be reached. For this a decision of renewing techniques and renewing strategies need to be decided.

## 4.1 Supply security analysis

Supply security analysis is one of the most important phases on strategic planning. It is a way to determine how an electricity distribution network will survive from a major disturbance situation. Supply security analysis gives an answer to how much overhead lines in forest need to be renewed to meet targets set in the electricity market act. In general, how much cabling is needed to survive from a storm with electricity distribution disturbances under 36 hours.

Supply security analysis focuses on an earlier major disturbance that have occurred in a distribution area. A good understanding of major disturbance is needed for the analysis. Therefore studying of earlier major disturbances is necessary. For the analysis information of fault fixing organization and network is needed.

### *4.1.1 Definition of major disturbance*

There is no exact definition for a major disturbance in electricity distribution. However, it is possible to divide disturbances to major disturbance and normal state disturbance. A normal state disturbance can occur due a single fault that causes an outage that includes for example from hundred up to few thousand customers and lasts maximum of few hours. A major disturbance can be discussed for example when a storm causes several simultaneous faults to distribution system. (Verho, P. et. al, 2010)

One definition of major disturbance is that *A major disturbance is a situation where more than 20 % of DSO's customers are without electricity or 110 kV line, 110/20 kV substation or main transformer fails for several hours*. (Järventausta et al., 2005) Another definition for major disturbance is based on the consequences and not on the grid. *Major disturbance on electricity supply is a long-term and/or wide outage that causes the fire and rescue service or another public operator to take action to minimize personal injuries and property damages.* (Verho, P. et. al, 2010)

Major disturbances can also be divided into three different classes depending on the damages that they cause and the probability for their appearance. Class I major disturbance causes outage that lasts in total around 48 hours and it appears once in five years. Next class of major disturbance, class II, level is defined so that it causes outage of 120 hours and frequency of its appearances is once in every 20 years. Damages from class III major disturbance are four times bigger than in class II major disturbance. Repairing faults from a class III major disturbance is estimated to last at least two weeks and it appears once in every 100 years. (Partanen et al., 2006)

To simplify classification of major disturbances that have been experienced earlier, it is possible to divide typical direct consequences into two classes: a long interruption in rural areas and a quite short but broad interruption at city areas. A base case for long interruption in rural area is a situation where a storm causes thousands of customers experience interruption that lasts more than 12 hours and hundreds of customers suffer interruption that lasts for few days. In city areas this could mean an interruption that one or two substations are without electricity for a little while. (Verho, P. et. al, 2010) Figure 4.1 demonstrates how broadness and the time of interruption effect to the seriousness of disturbance.

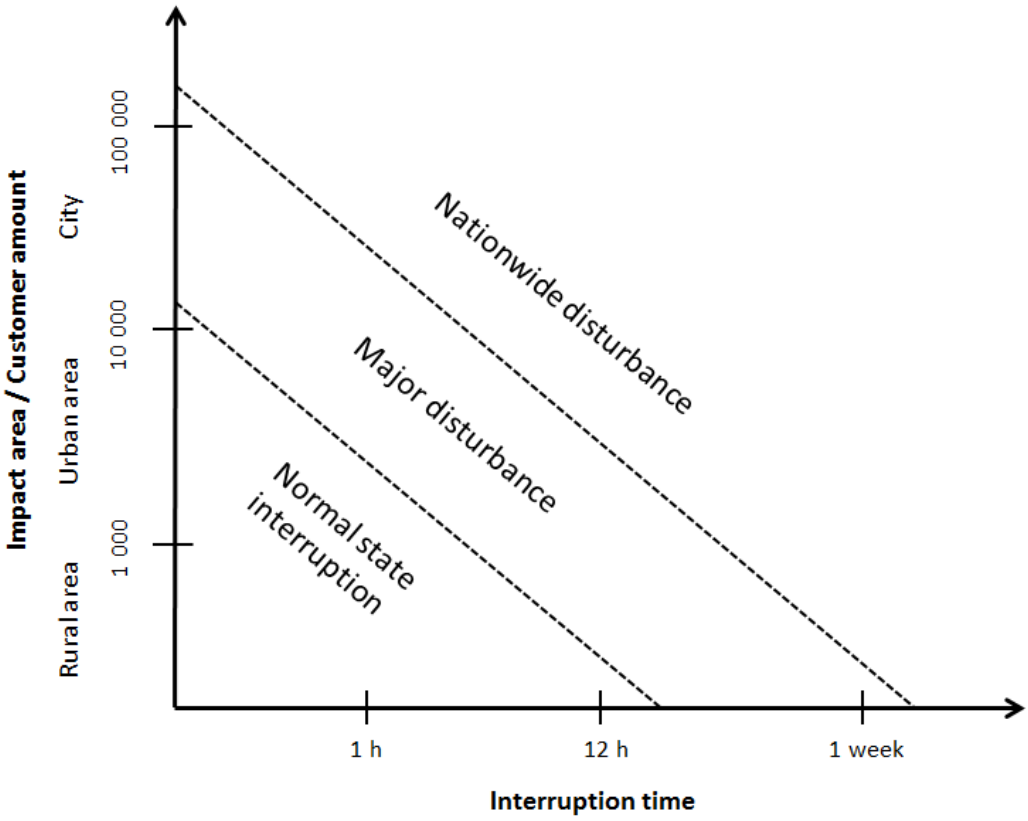


Figure 4.1 Seriousness of a disturbance compared to broadness and time of interruption (Verho, P. et. al, 2010)

### *4.1.2 Data to be applied in major disturbance modelling*

An important part of major disturbance modelling is the gathering of data from previous major disturbances. If DSO has never experienced a major disturbance, it can use major disturbance data from a similar DSOs network and disturbance experiences. In this case we have data from few different major disturbances in the study area.

The most crucial information for major disturbance modelling, can be divided into five different categories. These categories are MV and LV network information of the study area, fault data, customer data, fault repair organization and cost information. (Partanen et al., 2012)

From the study areas fault and customer information it is possible to constitute an understanding on the amount of customers without electricity and the duration of the disturbance. Fault repair organization tells us how much mechanics and other personnel have been available for fault clearance and how time consuming fault fixing is. Network information carries the most important role, for example cabling/weather proofing rates helps to sort out how large proportion and witch parts of MV and LV networks stays intact. When combining cost information to previously presented information, it is possible to get a good understanding about DSOs financial losses. (Partanen et al., 2012)

### *4.1.3 Mathematical modelling of major disturbance and required major-disturbance-proof rates*

Modelling of major disturbance helps to understand what actions need to take place to match the requirements for supply security in Electricity Market Act (588/2013). These actions can be for example cabling or increasing fault fixing capacity. Modelling can also be used when estimating financial costs of major disturbance. (Partanen et al., 2012)

When modelling major disturbance, it is essential to understand what are the most important factors that effects broadness and length of major disturbance. An example fault clearance curve of faults/customers without electricity in relation to time at major disturbance is shown in figure 4.2. There is also described the main principles that affect the shape of the fault clearance curve. In real major disturbance situations the development of customers without electricity is not always so straightforward. The fault clearance curve might have multiple peaks, which makes modelling more challenging. (Partanen et al., 2012)

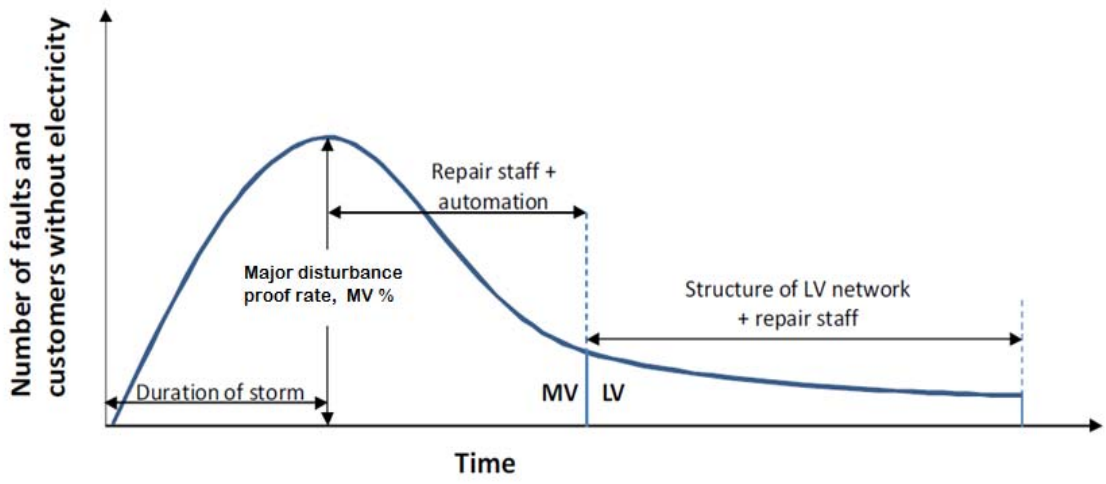


Figure 4.2 Customers without electricity and fault amounts in function of fault clearance time. Main principles that affect shape of the curve are also described. (applied from Lassila et al., 2013)

The highest point of fault clearance curve is the moment when fault amounts stop increasing. Duration of the storm and MV weatherproofing rate has the greatest effect for this point and it can be used as a starting point. By earlier statistics it takes from few hours to half a day to reach this point. After that MV fault clearance starts. MV fault clearance helps to restore electricity supply to most customers due large effect that one MV fault can have. Therefore it is important to know when all of the MV faults have been cleared and how much it has taken persons and person hours to fix these faults. After all MV faults have been cleared, fault fixing capacity can be focused to LV faults. (Partanen et al., 2012)

As mentioned before, major disturbance modelling is based on statistical data from earlier major disturbances. This means that the outcome will tell the level of preparedness that should have been in the earlier major disturbance to be able to clear all faults in 36 hours. In the upper edge of figure 4.3 is demonstrated the input data for modelling and at the lower edge is the outcome. (Partanen et al., 2012)

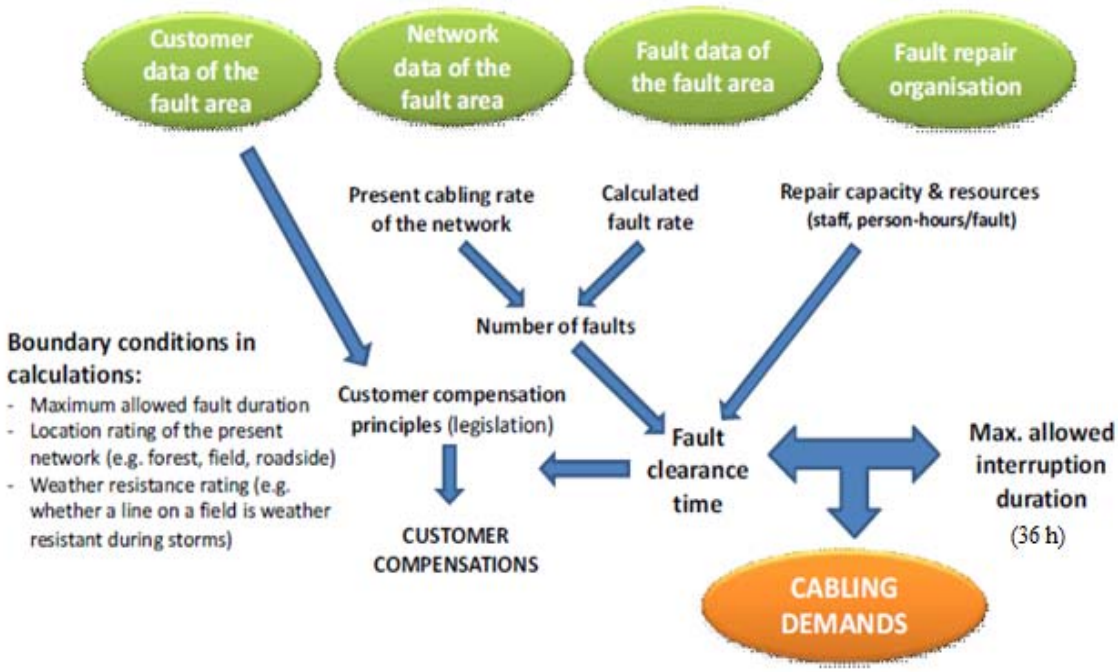


Figure 4.3 Data for major disturbance modelling and how they can be used in supply security analysis. (Lassila et al., 2013)

As figure 4.3 presents, customer data doesn't have any affect to fault clearance time, but it is needed to determine customer outage costs and standard customer compensation payments. Outage times of customers together with network structure from previous storms can be used to evaluate the amount of customers that would not have experienced an outage if weatherproofing rates were higher. Network data of the fault area helps to understand how present structure of the network effect fault amounts and customers without electricity. Major disturbance proof rates for MV and LV network tells length of the network that is safe from the storms. When major disturbance proofing rates grow fault amounts drop and therefore fault clearance times can be decreased. Fault data of the fault area contains information about fault amounts and progression of fault clearance. Fault repair organization gives the used manpower and working hours of personnel. (Partanen et al., 2012)

The required major-disturbance-proof rates (MPDR) can be determined by using information about fault repair organization, fault data and network. These fault information can be collected from worst major disturbance that has occurred in the study area. The required MDPR can be calculated the next way (Haakana, 2013)

$$MDPR = 1 - \frac{t_{\text{Allowed}}}{t_{\text{fr}}} * \frac{N}{\lambda * l} \tag{4.1}$$

Where $t_{\text{Allowed}}$ = Maximum allowed interruption duration [h]

$t_{\text{fr}}$ = Fault repair time [h/fault]

$N$ = Number of resources

$\lambda$ = fault rate [faults/ km]

$l$ = length of network vulnerable to major disturbance [km]

The equation (4.1) might seem trivial for the purpose it is for, due low amount of variables. Determination of these variables requires a profound analysis of major disturbance data. Estimation of required MDPR levels can be carried out by calculating extreme values first. For example minimum MDPR for MV network is calculated assuming that LV network has 100 % MDPR-level and all fault repair capacity can be addressed to MV network and vice versa. Points between these extreme values can be determined by drawing a line between extreme values when MV and LV major-disturbance-proof rates are located in y- and x-axis. (Haakana, 2013)

### 4.2 Network reliability

Normal state reliability can be measured in many ways. One indicator is customer outage costs used in the regulatory model. However, there are also other indicator that helps to understand network reliability in a different way. To understand the message different reliability indicators it knowledge of fault isolation and fixing process is needed. Fault isolation process and different reliability indicators are presented next.

### *4.2.1 Fault isolation process*

When calculating reliability of electricity distribution network, it is essential to know how fault fixing/isolation process works. This way it is possible to estimate how long fault isolation and fault fixing takes time. Fault isolation times and the impact area of a fault are needed when calculating COC. Knowing the fault isolation process helps to determinate outage times for customers in substation m depending on location of where the fault occurs. figure 4.4 represents fault isolation process.

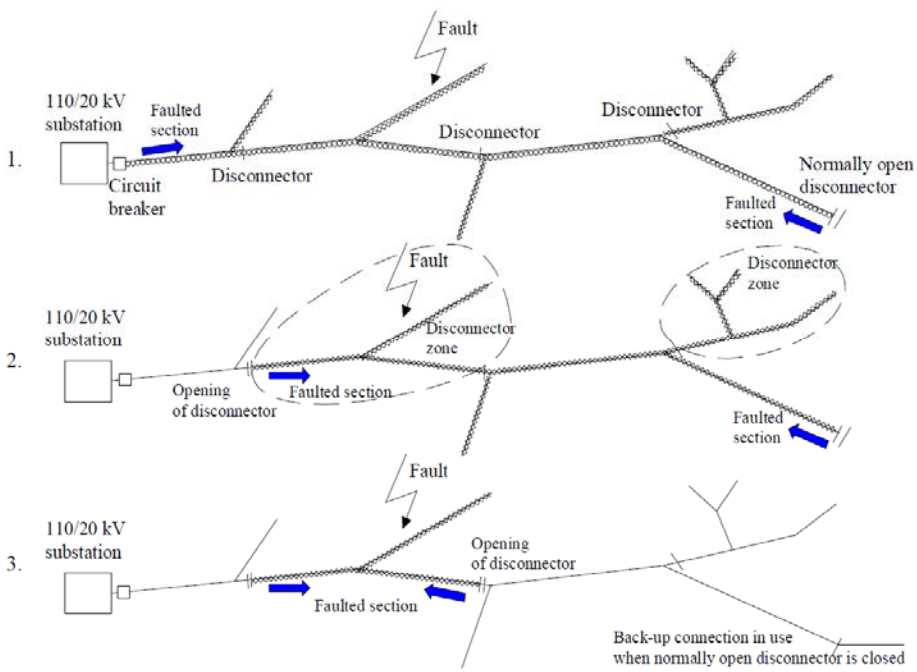


Figure 4.4 Fault isolation process in three steps. (Haakana, 2013)

First step when a fault occurs, is that the feeders circuit breaker opens. At this point the whole feeder is without electricity. Second step is to start opening disconnectors to isolate the fault into a smaller area. Third step is fault fixing. At this moment the fault is isolated into one disconnector zone and electricity distribution is restored to healthy disconnector zones. The fault isolation time depends mostly on the type and amount of disconnectors. Remote controlled disconnectors decrease fault isolation time due shorter control time than with manually controlled disconnectors.

### *4.2.2 Reliability indicators*

Nowadays the reliability of distribution network is a significant factor when considering renewing old OH-network. This can be seen also in COC that is used in the regulation model. Other way to measure reliability of distribution network is to use indicators defined in standard IEE 1366-2001 and are used globally. These indicators are SAIFI, SAIDI and CAIDI. Normally these are used to calculate reliability at normal state, but they are also suitable for examination of major disturbance, especially SAIDI and CAIDI. SAIFI describes average number of interruptions experienced by customers in a certain period of time. On the other hand SAIDI represents average duration of interruptions that customers experience over certain time period. CAIDI depicts the average duration of interruptions over a certain period of time. (Partanen et al., 2006) Definitions of these indicators are

SAIFI system average interruption frequency index

$$SAIFI = \frac{\sum c \cdot n_j}{N} \tag{4.2}$$

SAIDI system average interruption duration index

$$SAIDI = \frac{\sum i \cdot \sum c \cdot t_{ij}}{N} \tag{4.3}$$

CAIDI customer average interruption duration index

$$CAIDI = \frac{\sum i \cdot \sum c \cdot t_{ij}}{\sum c \cdot n_j} = \frac{SAIDI}{SAIFI} \tag{4.4}$$

Where $c$ = Number of customers effected by the interruption

$i$ = Number of interruptions in a certain time period

$N$ = Number of customers

$n_j$ = Number of interruptions experienced by customer j

$t_{ij}$ = Interruption duration i of customer j

(Partanen et al., 2006)

## 4.3 Network development

When improving reliability and supply security, a decision has to be made about network technologies that are going to be used. Supply security and allowed interruption times are main driver when choosing renewing techniques. When renewing techniques are decided question of when and where should the network be renewed first. To answer this question some very in-depth analysis need to made of present state of the network. Investment and profitability calculations can be used to help determine which parts should be renewed first to for best revenue. Different ways to improve reliability supply security as well as how to determine the most profitable way of doing it, is discussed next.

### *4.3.1 Techniques to improve reliability and supply security*

When renewing electricity distribution network, DSOs have many different technological options that can be used to improve reliability. These are network automation, moving lines to roadsides, replacing overhead lines with covered conductor overhead lines or air cables, underground cabling and replacing vulnerable MV branch lines with low consumption by 1 000 V system. When developing network it is possible to use only one technique like cabling, but usually it has been techno-economically sensible to use an optimal combination of more than one technique. Most important network techniques and their effect on reliability and supply security on major disturbance situations with  are presented in table 4.1.

Table 4.1 Possible network techniques to reduce long outages. ↗↗ = substantial effect/fast implementation (1-5 a), ↗ = moderate effect/average speed implementation (5-15 a), - = no effect/very time consuming implementation (15-40 a). (Partanen et al., 2012)

| Technique | Effect on normal state reliability | Effect on broadness and length of disturbances | Time consumption of implementation |
|---|---|---|---|
| Network automation | ↗↗ | - | ↗↗ |
| Simple, low-cost primary substation | ↗↗ | ↗ | ↗↗ |
| Overhead lines in present location | - | - | ↗ |
| Overhead lines in roadsides | ↗↗ | ↗ | ↗ |
| Covered conductors | ↗↗ | - | ↗ |
| Aerial cables | ↗↗ | ↗ | ↗ |
| 1 000 V system, cabling | ↗↗ | ↗↗ | - |
| Cabling of MV network | ↗↗ | ↗↗ | - |
| Cabling of LV network | ↗ | ↗↗ | - |

Network automation is a good way to improve normal state reliability and to decrease customer outage costs. With remote control disconnectors it is possible to decrease fault clearance time due shorter fault isolation times. Other good way to improve reliability is to use switching stations. This how one feeder can be divided into several protection zones. When using switching stations customers upstream from the station don't suffer outages caused by faults downstream from the switching station. Only problem with network automation is that it doesn't reduce the amount of faults, it only reduces the impact area of a fault. (Partanen et al., 2006)

New primary substations helps to create also more protection zones via new and shorter feeders. These help to improve reliability and supply security, by placing new primary substations into areas where feeders are long and there are only few feasible backup connections. When building simple, low cost primary substations, areas with low

consumption can also become feasible alternatives for placement of primary substations. (Partanen et al., 2006)

One option to improve reliability is moving lines from forest to road sides. This way fault amounts and fault fixing times at normal state can be decreased. Fault rates decrease because there are trees only on the other side of the overhead line. Fault fixing times decrease due easier location of faults and easier accessing to faulted lines. When building to roadsides length of the network stays about the same. Consumption is usually placed close to infrastructure, especially roads. This means that it is possible to decrease the amount of branch lines. However, due to trees on the other side of overhead lines at roadsides, it is not possible to build secure distribution for major disturbance situations with this technique. (Partanen et al., 2006)

Covered conductors improves normal state reliability by preventing high-speed and delayed auto reclosings. These auto reclosings are prevented by isolating cover over the line that protects the line from tree branches. It doesn't decrease the amount of faults especially at major disturbance situations, because falling tree will cause a fault also with this line type. However, in northern Finland this helps to protect against heavy snow loads and disturbances cause by them. Covered conductor lines are approximately 30 % more expensive than normal overhead lines. (Lakervi et al. 2008)

Underground cabling is the best way to protect distribution network from faults caused by weather like thunder and trees falling over conductors. The greatest improvement in reliability and supply security with cabling can be achieved by replacing overhead lines in forest with cables. Underground cables have 50-80 % less faults at normal state than overhead lines. At major disturbance situations cabling is one of the most important ways to improve supply security. Underground cables also have lower maintenance costs than overhead or covered conductor lines. Only downside in cabling is that it is expensive and time consuming. Cabling costs can be decreased by developing underground cables and ploughing techniques. (Partanen et al., 2006)

Reliability and supply security can also be improved with operational actions. For example tree clearing reduces reclosings and helps to protect against snow load effectively. Increasing fault fixing capacity helps to decrease outage times especially in major disturbance.

### *4.3.2 Investment calculations*

Investment calculations are used when deciding between different network renewing or investing options. Usually decisions are based on profitability. Nowadays one of the most important factors in renewing network is reliability. So as said the investment profitability calculations should be based on life-cycle costs of the options to be compared. Usually renewing has been focused on old and mechanically poor network that is at the end of its lifetime. Due the new Electricity Market Act some network have to be renewed before it is at the end of its lifetime. Therefore regulated asset value of demolished network should be also taken into account. A simplified example of investment profitability calculations could be to compare investment costs, savings in COC, maintenance costs and reasonable return on capital from this investment. The next inequality shows a simple way how to estimate investment profitability.

$$Investment\ cost < \Delta COC + \Delta M + \Delta RRC + \Delta TOTEX + \Delta Depreciation + S \quad (4.5)$$

Where $\Delta COC$ = change on customer outage costs

$\Delta M$ = change on maintenance and fault fixing costs

$\Delta RRC$ = change on reasonable return on capital

ΔATOTEX = change on allowed total operational expenditure

S = security supply incentive

If investment cost is smaller than net present values of savings it causes then the investment is profitable and vice versa. Because COC, M and RRC can be referred as annual income and investment cost as one-time cost, they have to be made equivalent. This can be done by

using net present value for annul costs and summing them or by using annuity of investment. This net present value is not the same as used in the regulation model. In this case net present value tells how much all of the coming income or savings would be worth today. It can be calculated the next way

$$NPV_{\mathrm{a}} = \sum_{T=0}^{N} \frac{C_t}{(1+r)^T} \tag{4.6}$$

Where $NPV_{\mathrm{a}}$ = net present value

$r$ = interest rate

$T$ = review period

$C_t$ = annual cash flow

When a large investment has long-term effects, can annuity be used to modify investment costs to be equivalent with yearly costs. Multiplying annuity with investment cost provides the annual amount of money that is needed to cover the cost of capital and interests. Annuity can be calculated in the following way.

$$\varepsilon = \frac{r/100}{1-\frac{1}{(1+r/100)^T}} \tag{4.7}$$

Where ε = annuity

### 4.4 Renewing strategies

After network renewing techniques have been decided next question is how are they to be implemented. For the implementation of chosen renewing techniques should be created a strategy to follow. Because the new Electricity Market Act allows interruptions with 36 h max interruption time in rural areas, networks weatherproofing rate doesn't have to be 100%. This means that a share of the overhead line network can be left exposed to trees that can fall over these lines. Big question is that witch of these line sections that are vulnerable to faults caused by weather should be renewed. There's many ways to prioritize line sections that can or cannot be left vulnerable to falling trees.

### *4.4.1 Cabling strategies*

This chapter presents cabling strategies that have been studied earlier in literature. These strategies are full-scale underground cabling, underground cabling with rolling technique, cabling of the oldest parts of the feeder, cabling of the most unreliable line sections and the combination of underground cabling and network automation.

Full-scale underground cabling is not common way of renewing network in rural areas. This is mostly due the fact that underground cabling has been significantly more expensive than building overhead lines. In rural areas the amount of MV lines per customer is much higher than in urban areas due a widespread customer base. This is one reason why it has been uneconomical to use full-scale underground cabling as a renewing technique in rural areas. In reliability and supply security point of view, full-scale cabling is the best solution because of its low fault rates. This means that even severe weather conditions would not cause interruptions on electricity supply. (Haakana et. al, 2009)

Underground cabling with rolling technique is carried out starting from the beginning of the feeder and proceeding to the end of the feeder. Usually customer density is higher close to primary substations than in the end of the feeder. This way customers at the beginning of the feeder benefit first from cabling. Therefore rolling technique helps to meet the requirements of the new Electricity Market Acts for years 2019 and 2023 easier (50 % and 75 % of customers have to be secured). A moveable switchgear can be placed into the intersection of underground cable and old overhead network. Moveable switchgear eliminates the effect of faults in overhead network from cable network. (Haakana et. al, 2009)

For aged feeders that have poor reliability, cabling of the oldest part of the network can be a suitable solution for renewing strategy. When renewing focuses on line sections that are at the end of their lifetime, increase the feeders net present value is fast. As net present value of the network increases also reasonable return on capital also increases. These old line sections should also be located in forests, otherwise reliability benefits would be relatively

modest. But when old fault prone line section are cabled, reliability improves in the whole feeder. (Haakana et. al, 2009)

One cabling strategy is cabling of the most unreliable line sections. Here renewing focuses on line sections that are located in forests or that are otherwise fault prone. Cabling of the most unreliable line sections improves reliability for the whole feeder due reduction of fault amounts. If these investments can be allocated to old overhead lines, benefits of this strategy will also become greater. Feeders that have good reliability at the beginning and poorer at the end of the feeder are great targets for this strategy. Some challenges may occur due lines to be renewed can be located widely along the network. If renewing actions takes place at short line sections with long distances between them, cabling becomes more difficult and expensive. Therefore its sensible to determine line sections to be renovated so that they are located close to each other. When renewing can be targeted on longer continuous line paths, cabling becomes more economical. (Haakana et. al, 2009)

Combination of cabling and network automation is a strategy that is feasible for feeders that supply electricity to both urban and rural areas. Network automation, switchgears and remote controlled disconnectors, helps to improve normal state reliability. When using cabling and automation together it is possible to build weatherproof cable network to urban areas and overhead network in rural areas inside the same feeder. This way one feeder can be split into smaller protection zones and faults in the rural area network don't affect the cable network in urban area. When network automation is used cabling amounts can be left smaller to reach same reliability improvements than in earlier mentioned cabling strategies. This means smaller investments costs and more profitable investments. (Haakana et. al, 2009)

### *4.4.2 Prioritization methods for renewed line sections*

Thou literature presents many different cabling strategies, this works focuses on three different prioritization methods to determine whether line section can be left vulnerable to trees or not. These methods of prioritization are maximizing the amount of customers that

the cabling makes major disturbance proof, cabling line sections that cause most customer outage costs and minimizing excavation costs for medium voltage cabling.

Maximizing the amount of major disturbance proof customers doesn't mean underground cabling with a rolling technique because overhead lines in open areas are also perceived as major disturbance proof lines. Using this prioritization method the peak of customers without electricity in major disturbance should decrease heavily.

There are many factors that effects the COC value for a line section. For example amount of customers, their yearly energy, fault frequency of line section and network topology are all connected to COC of the line section. This means that line sections that have most customers or that are most vulnerable to faults may not be the ones to be cabled.

When building cable network excavation condition imposes a large amount of investment costs. If investment costs are to be minimized, cabling will focus on areas where excavation conditions are relatively easy. In rural areas this means that cabling would be avoided in rocky areas, due more expensive excavation costs.

Securing main lines from falling trees improves supply security and raises major-disturbance-proof rate. Branch lines that are vulnerable to falling trees in the beginning of a feeder are also important to be secured by cabling or network automation. If these branch lines malfunction the whole feeder will also suffer from outages.

### 4.5 Network planning tools

Nowadays there are many programs and software that are used for network planning and that enforce strategic planning. Also some softwares meant for distribution management are useful for strategic planning. Distribution management system (DMS), network information system (NIS) and its properties used in this work are introduced next.

### *4.5.1 Distribution management system*

ABB DMS 600 is a geographical distribution network management system that is used in Caruna. The DMS 600 workstation enables operative persons of utilities to monitor and operate their electricity distribution network. The program has functions like network topology management, operational simulations, fault location, switching planning and outage data management among many other functions. The outage data management function is used in this work. (ABB 2012)

The outage data management is more suitable for normal state outage data management than major disturbance situations. For example it is not possible to get data of fault amounts in major disturbance situations. The amount of feeders and customers that suffer from disturbance can be determinate from the outage data. Thou exact fault amount of major disturbance is not available anywhere, the outage data management allows to examine fault clearance times. From DMS reporting service it's possible to get data of the amount of customers without electricity in function of time. From this data it's possible to determine how fault isolation and clearance advanced in the reference storm.

### *4.5.2 Network information system*

Trimble NIS is used for analysis to find line sections corresponding to chosen development strategies. Network information system also known as NIS is the most substantial planning tool for electricity distribution network. Network information system is used for example network analysis, network planning, long term planning, maintenance planning and documentation. Information about electricity distribution network is saved in to a database. The data in NIS is in component level. Network information system retrieves information from the database and it uses graphical interface. This way network simulation is easy and users can see the network on a map as it is located. The graphical interface enables easy planning and calculating electrical values for old and added network. (Lakervi et. al, 2008)

Caruna Oy uses Trimble NIS network information system, which enables versatile analysis and calculation. Trimble NIS includes among other thing customer data, maintenance information of components, location and environment information of components together

with fault data imported from distribution management system. In addition to electrical calculations Trimble NIS is able to simulate network reliability and it can be used for advanced analysis. Thematic spatial analysis tool (TSA) can combine data from external sources to network data and that enables a wide range of advanced analysis. Trimble NIS enables diverse analysis considering current state of the network.

### *4.5.3 Reliability based network analysis*

In this work reliability calculations are made by Trimble NIS RNA calculation witch is a tool for reliability based network analysis. Trimble NIS RNA-tool is based on the LuoVa report. The goal on LuoVa-project was to create a calculation tool that simulates distribution network reliability. (Verho et. al, 2005)

The RNA-tool calculates reliability on component level. Parameters for every component croup can be set separately. These parameters determine fault frequencies and fault repairing times caused by various reasons. There are 177 parameters that the RNA-tool uses for reliability calculations of MV network. Fault frequency parameters can be set uniquely for different king of environments. These fault frequencies represents average values for the concerned environment type. This way environment factors can be taken into account. For example fault frequencies can be set depending on density of forest. Trimble NIS RNA tool does very advanced simulation for normal state reliability. However, it is not suitable for major disturbance modelling. (Trimble NIS, 2011)

In this work the RNA tool is used to calculate changes that investments make to normal state reliability. RNA parameters are set so that RNA calculation results correspond to real life reliability indicators. Fault amounts, SAIFI, SAIDI, CAIDI and customer outage costs are used to calibrate RNA parameters.

# 5. IMPLEMENTING PRIORITIZATION METHODS

Three different renovation location prioritization methods were chosen for the approach to overhead line renovation. These methods are prioritization by customer outage costs, maximizing customers in major disturbance proof network and minimizing excavation costs in medium voltage network renovation. This chapter presents methodologies used to locate overhead lines in forest by different prioritization methods.

In this work Trimble NIS is used for implementing different prioritization methods. It has various features that helps to create tools for these prioritization methods. Most important for this work are thematic spatial analysis, reliability based network analysis and background maps.

## 5.1 Prioritization by customer outage costs

In this prioritization method line sections that cause the most customer outage costs are chosen to be renewed. With Trimble NIS and its NRA calculation it is possible to calculate COC that line sections cause. The RNA calculation gives normally results on a feeder level. From calculation results that RNA saves to the database it is possible to sort out how much different line sections cause customer outage costs. For the analysis it is calculated how much a line section causes COC per meter. To visualize COC that line sections cause a function in Trimble NIS called thematic spatial analysis (TSA) need to be used. With thematic spatial analysis it is possible to color line sections by the amount of COC per meter that they cause as shown in figure 5.1.

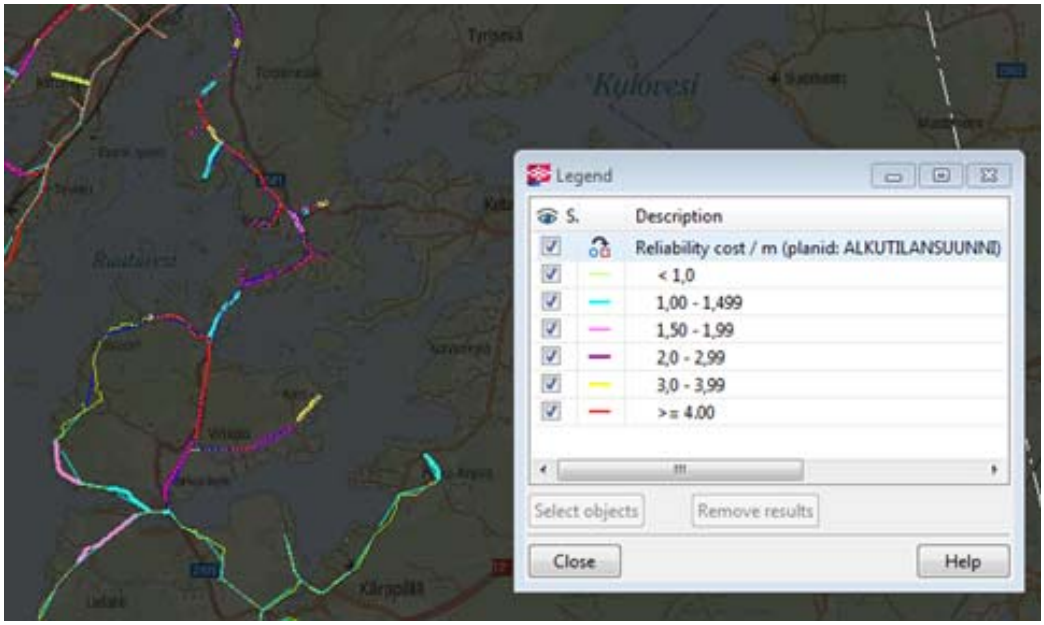


Figure 5.1 Line sections colored by the amount that they customer outage costs per meter. The figure shows coloring in six different scales. Green being line sections that cause the least COC and red line sections that cause the most COC.

As seen in figure 5.1, after building a thematic spatial analysis from RNA calculation results, it is very easy to see which line sections are to be selected for renovation first. Red line sections cause most COC, therefore they are cabled first then yellow, purple etc. until the needed amount of overhead lines in forest are renewed with cables.

## 5.2 Maximizing customers in major disturbance proof network

For this prioritization method a very straight forward approach can be used. There are two factors that effects the selection of renewed line sections with this method. First one is the forest factor and secondly secondary substations customer amounts. For secondary substation and its customers to be major disturbance proof, means that the network that is feeding them need to be in open area or cable. Fully cabled feeding to a secondary substation that can be classified as major disturbance proof is not necessary. To find the right places for cabling customer amounts of secondary substations are colored to the network topology as in figure 5.2.

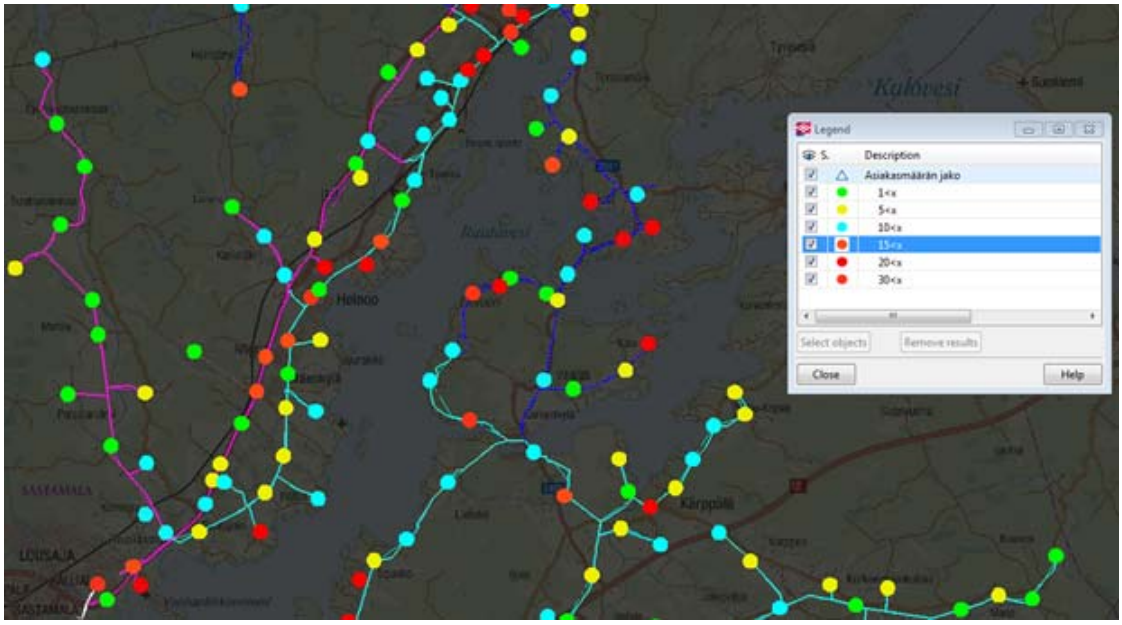


Figure 5.2 Secondary substations highlighted in the network according to customer amounts.

After secondary substations with most customers has been located, every overhead line of medium voltage network that is in forest between main substation and these secondary substations need to be renewed with underground cables. This starts with areas that have the greatest customer density and continues downwards from there until the needed amount of overhead lines in forest have been renewed.

### 5.3 Minimizing excavation costs in medium voltage network

In this prioritization method the focus is in studying effects of minimizing excavation costs in medium voltage network. Excavation costs are calculated with a background map that shows excavation conditions. Excavation conditions of this background map are made to be corresponding with EMAs definitions for excavation condition classes. Corine land cover data works as a basis for the excavation condition background map. Normal, hard and very hard excavation costs that are based on building density are also included in the excavation condition background map. Figure 5.3 presents an example of the excavation condition background map and forest information in the same view with the network.

Figure 5.3 Excavation condition on the background map. Forest information is colored on top of the network topology.

In the figure 5.3 green, yellow and orange blocks on top of the network describe forest. Orange and yellow blocks represents denser forest than green blocks. In the back ground map green color corresponds easy excavation condition, light brown represents normal excavation condition and red shows where excavation condition is difficult.

Renewed line sections are located by cross referencing excavation condition background map, network topology and forest data. In this case environment information of overhead lines is colored on top of network topology to find out which line sections are located in forest. After this is done in the network information system, long continuous line sections are found to be renewed. Lines selected for renovation are in the picture colored with the forest information blocks and the background map shows green around these lines. When excavation costs are minimized, long continuous cabling routes helps to lower the unit costs of excavation.

# 6 SUPPLY SECURITY IN THE STUDY NETWORK

The new Electricity Market Act obligates DSOs to improve their network so that the 36 h outage limit won't be exceeded in major disturbance. This section focuses on examining supply security of electricity distribution network in the study area. The current state of the network is defined first. Information about the reference storm is also needed together with network topology for the supply security analysis. Required major disturbance proof rate in the study network for the 36 h outage limit in the Electricity Market Act will come out as a result from the supply security analysis.

## 6.1 Basic information about network

The study area represents typical rural electricity distribution network that Caruna has. The study area consists from feeding areas of two primary substations. In the study area the medium voltage network close to the end of its lifetime, the average age is roughly 29 years. Table 6.1 presents basic information of the analyzed network.

Table 6.1 Basic information about the analyzed network.

| Medium voltage | |
|---|---|
| Overhead lines [km] | 472 |
| Forest rate [%] | 32 % |
| Underground cables [km] | 37 |
| Average age | 34 |
| **Disconnectors** | |
| Remote controlled [pcs] | 27 |
| Manual [pcs] | 194 |
| **Low voltage** | |
| LV overhead lines [km] | 769 |
| Forest rate [%] | 29 % |
| Underground cables [km] | 312 |
| Average age | 37 |
| Customers [pcs] | 9300 |

As table 6.1 shows forest rates are not so high as typically in Finland. In the study area there are lot of agricultural activity. The analyzed network has also three city plan areas. City plan areas are not in the scope of this work. The medium voltage network of the study area is presented in figure 6.1.

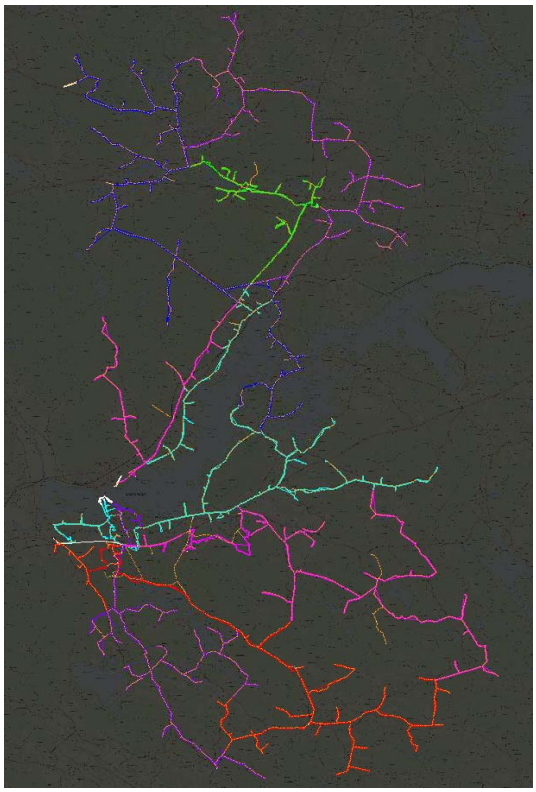

Figure 6.1 Medium voltage network of the study area. Network topology is colored on a feeder level.

The analyzed network has long feeders as seen in figure 6.1 longest feeder up to 65 km. Long feeders are usually harder to manage in fault situations than short feeders. The study network has also a lot of branch lines. This means if a fault occurs in the beginning of a branch line, the whole branch will suffer from outage until the fault is fixed. Great amount of branch lines makes fault location also harder because it gives more possibilities for the fault location calculation.

## 6.2 Supply security analysis

Supply security analysis is based on earlier storm due the fact that it is difficult to predict due the reason that there is no other fact based information available to base the analysis on. The data from earlier major disturbances is quite limited. This is because the systems that are meant to gather information from normal state disturbance situation. Total fault fixing time for medium voltage network could be fetched from DMS. To get accurate medium voltage network fault fixing time for the study area, simulation for previous fault situations was used. This way it was possible to calculate fault fixing time for medium voltage network in a precisely designated area.

Fault fixing time for low voltage network was more challenging task. At the time of the reference storm automatic meter reading from smart meters wasn't fully operational so there is no low voltage network interruption data available. The fault fixing time for LV network was determined from a work flow control system called Care Center (CaCe). From CaCe it's possible to sort out assignments that restore electricity distribution for customers in low voltage network. For example assignments that didn't lead to restoration of electricity distribution like tree clearing without interruption, were left out from this analysis. When assignments that restore distribution are listed and summarized cumulatively it's possible to calculate when low voltage fault fixing started and when it ended. This gives a fare estimate of the time that it took to fix all faults in the low voltage network.

Forest rate for medium and low voltage overhead line networks was determined using data from the Finnish Forest Research Institute, Metla. Metla provides forest data with spatial information. The forest data used in this work is consist of 20 m times 20 m sized rasters that holds information about the location and average height of trees inside the raster. The raster data is based to a laser scanning of Finnish forestry that was made in the year 2011. This makes it easy to determine forest rates when the coordinates of electricity distribution network is known.

Information about the amount of fitters that were working at the time of the reference storm is also needed. With the information about fitters, forest rate, fault fixing times and time that it takes to fix one fault it is possible to calculate an estimation about the amount of individual faults. Table 6.2 presents data of Tapani storm in the study area.

Table 6.2 Information from major disturbance

| | Total fault fixing times in Major disturbance [h] | Amount of fitters | Working hours per fault | Lines in forest [km] | Calculated fault frequency in major disturbance for lines in forest [1/km] |
|---|---|---|---|---|---|
| MV network | 120 | 10 | 12 | 161 | 0,62 |
| LV network | 77 | 10 | 9,6 | 315 | 0,25 |

With information from table 6.2 it is possible to calculate required major disturbance proof rate. Major disturbance proof rates can be obtained using the equation (4.1). As mentioned in chapter 4.1.3, when calculating major disturbance proof rate for medium voltage network the MDPR for low voltage network is assumed to be 100% and vice versa. Using this method $MDPR_{LV}$ and $MDPR_{MV}$ will get the following values

$$MDPR_{\mathrm{MV}} = 1 - \frac{36\ \mathrm{h}}{12\frac{\mathrm{h}}{\mathrm{fault}}} * \frac{10}{0{,}62\frac{1}{\mathrm{km}} * 161\ \mathrm{km}} = 70\ \%$$

When $MDPR_{\mathrm{LV}} = 100\%$

And the same for low voltage network.

$$MDPR_{\mathrm{LV}} = 1 - \frac{36\ \mathrm{h}}{9{,}6\frac{\mathrm{h}}{\mathrm{fault}}} * \frac{10}{0{,}25\frac{1}{\mathrm{km}} * 315\ \mathrm{km}} = 53\ \%$$

When $MDPR_{\mathrm{MV}} = 100\%$

This is a very straight-forward way to determine extreme MDPR values. With these extreme MDPR values it is possible to determine the minimum MDPR level for both MV

and LV network. The minimum level can be determined by drawing a straight line between points (53%,100%) and (100%,70%) as shown in figure 6.2.

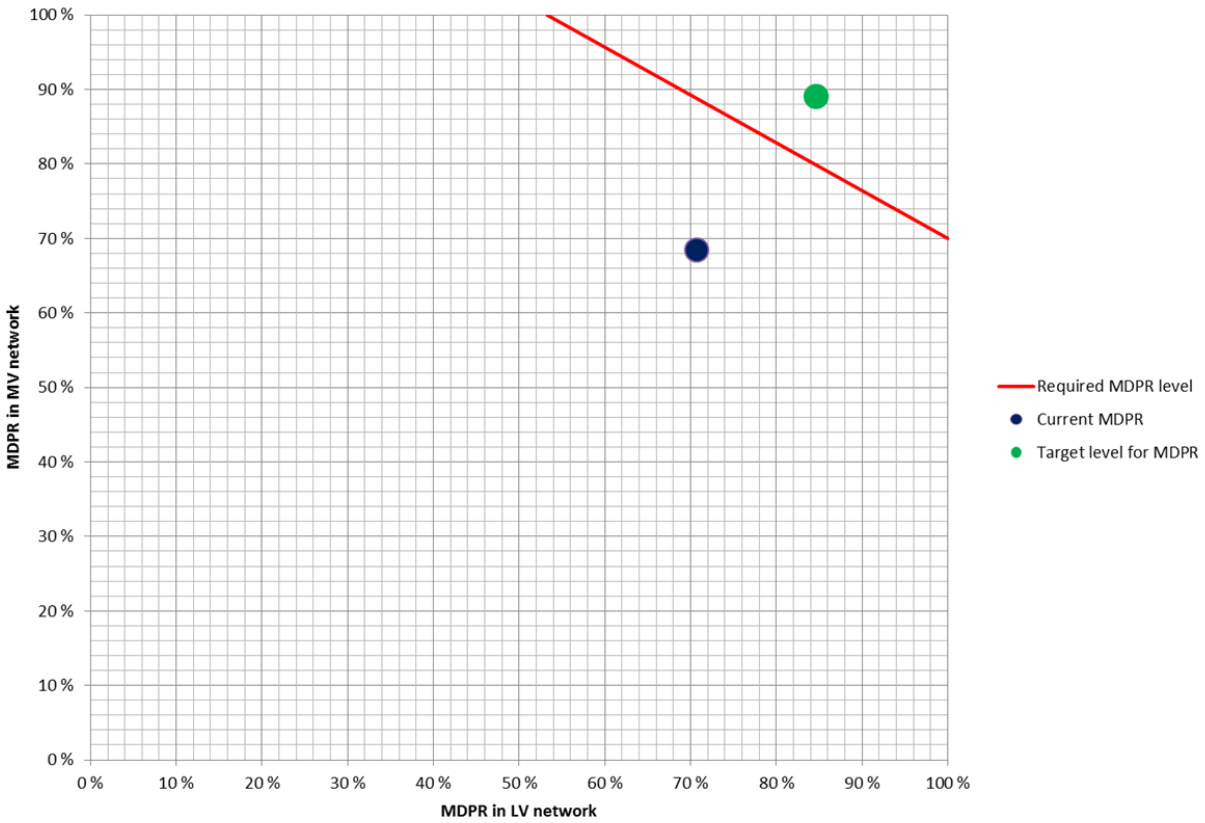


Figure 6.2 Required MDPR level to meet the outage limits of the new electricity market act. Balls represent study areas present state and target level for MDPR.

In figure 6.2 area above the red line can be referred as safe zone. When major disturbance rates for MV and LV network cross above the red line, the network fulfills outage limits set in the new electricity market act, assuming that the storm has the same intensity as the reference storm. Target for major disturbance proof rate level is chosen to be 89 % for MV network and 85 % for LV network. The target for MDPR level is chosen to be few percentage points higher what the minimum level requires to prevent crossing of the 36 hour outage time set in the electricity market act if a storm would be stronger than the reference storm. Another case would be timing of the storm if the storm starts in the middle of the night, the start of full-scale fault fixing would be delayed. Raising MDPR level for

21 percentage units MV network and 14 percentage units for LV network will mean a significant amount of cabling. With this target 105 km of MV overhead lines located in forest need to be renewed and for LV network there will be a 150 km renewal need for overhead lines in forest.

The required MDPR level can be affected so that it would not be as high as it is now. One way is to increase the amount of fitters in the study area. When there are more fitters, faults can be fixed faster and therefore required cabling amounts would be smaller. For example with 14 fitters results for required MDPR levels be the following: $MDPR_{\mathrm{MV}}$ = 58% and $MDPR_{\mathrm{LV}}$ = 35%, when the other is assumed to be 100%. This would mean with the same principle as in the earlier calculations approximately 50 km cabling in medium voltage network and 55 km cabling in the low voltage network. In the MV network this is almost half of the cabling amount than with 10 fitters. For the low voltage network the cabling amount its one third from the amount with 10 fitters. This difference that four fitters bring in to the cabling amounts seems to be relatively high. This is caused by the small size of the study area and high rate for open areas in the study area. In a larger area with higher forest rate relative differences in cabling would not be so drastic. Increased amount of fitters decrease cabling amounts and therefore investment costs. On the other hand higher amount of fitters means increase in OPEX compared to the option with less fitters. Cabling amounts can also be decreased by enhancing fault location, isolation and fixing processes.

# 7. IMPACT OF NETWORK INVESTMENTS

Large cabling amounts has a great impact to electricity distribution network and in almost every key figure used in electricity distribution business. Therefore it is important to examine impacts of large-scale cabling strategies as versatile as possible. In this work these examinations are divided into three main categories, which are network structure, reliability and profitability of investments. This work focuses mainly on studying medium voltage network but investment costs of low voltage network are also taken into account in these calculation due its essential part in supply security.

There are three different kind cabling renovation strategies to be compared in this work. They are three different ways to prioritize cabling renovation should be located. A: prioritization by caused customer outage costs, B: maximizing the amount of customers in major disturbance proof network and C: minimizing excavation costs in MV network.

In the study area Caruna has some planned investments that needed to be taken into account in network planning for these three cabling renovation scenarios. These investment plans are focused on medium voltage network cabling and network automation. The cablings are mostly focused on cabling mainlines located in forest. In this work these investment plans are included in all three scenarios as a base case. The same base case is used as a basis for every scenario. Therefore it can be excluded from investment, reliability and profitability calculations. The base case contains renewing of medium voltage overhead lines located in forest for 35 km. This means that the amount left for cabling in MV network is 70 km. This is still a sufficient amount for comparing the three renovation methods presented previously.

## 7.1 Investments and network structure

Renewing amounts are approximately the same in every renewing scenario. Renewing scenarios differ from each other in renewing locations. This causes differences in investment excavation conditions and in the amount of renewed secondary substations.

Figure 7.1 presents renewing locations for the base case and three different renewing scenarios in the study network.

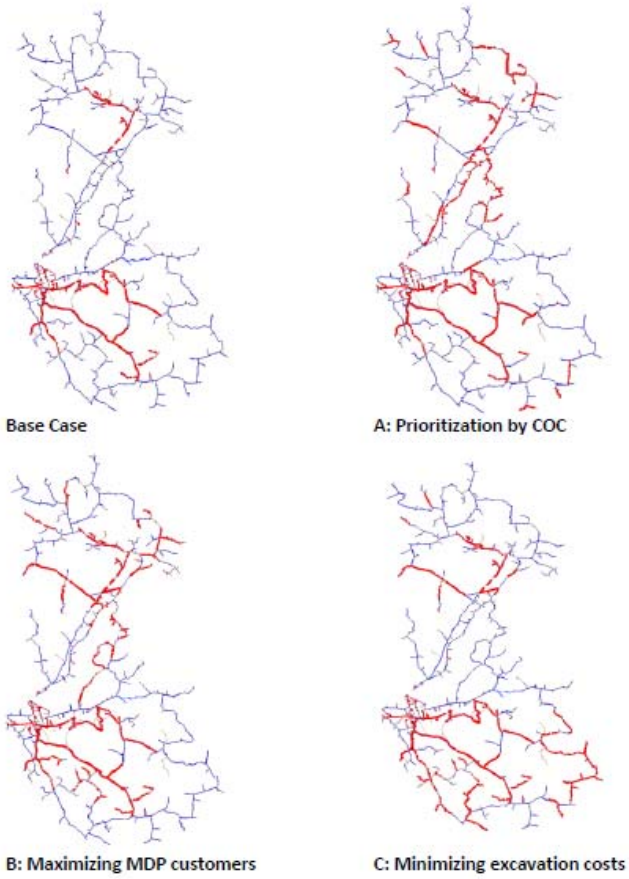


Figure 7.1 Renewing locations of renewing strategies. On top right corner in the base case which works as a basis for renewing scenarios. Cabling locations of renewing scenarios are added on top of the base case. Primary substations highlighted with red circles.

The base case shows renewing locations for which the renewing scenarios are based on. From the figure 7.1 can be seen that renewing in scenario A is more scattered than scenarios B and C. Renewing in scenario B is focused closer to primary substations than in other scenarios. This shows that primary substations are located closer to where most of the consumption locates. Scenario C has long continuous renewing routes. Long continuous cabling routes help to decrease excavation costs. On the other hand, some feeders are almost fully cabled and others will be left without cabling renovation in scenario C.

### *7.1.1 Investments and removed network*

Main effect to network structure and investment cost when renovating electricity distribution network to enhance supply security is large amount of cabling. This means that Cabling rate will increase and pole-mounted substations are replaced with pad-mounted substations. Renewing amounts are approximately the same in every plan, therefore change in cabling rates are close to each other in every renewing strategy. Investment costs for different plans in regulator prices and in 2014 monetary value are presented in figure 7.2.

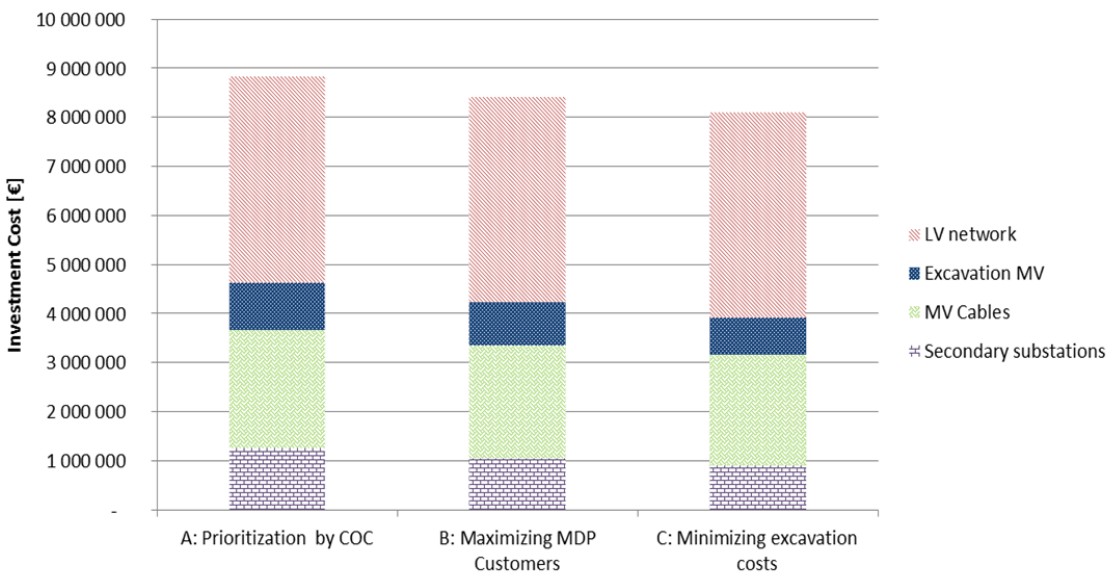


Figure 7.2 Investment costs for different renewing strategies with regulator prices in 2014 monetary value divided into major component groups.

As seen in figure 7.2 investment cost are greatest when renewed line sections are prioritized by COC they cause and lowest when excavation costs are minimized. This work focuses in studying MV network, therefore investment costs in low voltage network are calculated to be the same in every case. Main issues where investment costs differ according to renewing strategies are excavation condition, cross-sectional diameter of new cables and the amount and structure of secondary substations.

Excavation costs represents a great part of investment costs when building underground cable network. Different environments have different excavation price. Hard excavation

condition is considerably more expensive than easy excavation. Therefore it is important to study the effects of excavation conditions on investments. Excavation conditions of different cabling strategies are presented in table 7.1.

Table 7.1 Excavation conditions in different renewing strategies presented in EMA classes.

| EMA Class for excavation | A: Prioritization by COC | B: Maximizing MDPR Customers | C: Minimizing excavation costs |
|---|---|---|---|
| Easy | 85 % | 88 % | 100 % |
| Normal | 12 % | 11 % | - |
| Hard | 3 % | 1 % | - |

In case C excavation conditions are naturally 100% easy, due prioritization by excavation costs. In cases A and B easy excavation condition represent largest part of excavation conditions. Easy excavation condition is dominant because the study area and cabling are mostly placed in rural. In rural area excavation conditions are mostly easy. Cases A and B differ only little from each other. Case A has the more normal and hard excavation than case C. Normal excavation conditions comes from areas where there are residence close by or roads that need more attention. Hard excavation conditions are mostly caused by rocky areas. The prices for different excavation conditions are presented in appendix I.

To limit the scale of this work cross-sectional diameters of cables are not determined by electro technical dimensioning. Due the lack of site planning in this work, the cabling amounts are calculated to be 1,2 times longer than the existing network. Therefore cross-sectional diameters of new cables are determined by using the same or one step larger cross-sectional diameter what the renewed overhead line has. The spread of cross-sectional diameters of new cables in EMA classes for different renewing strategies are presented in table 7.2.

Table 7.2 Amount of installed underground cables in EMA classes for different renewing strategies.

| **Installed medium voltage cables** | | A: Prioritization by COC | B: Maximizing MDP Customers | C: Minimizing excavation costs |
|---|---|---|---|---|
| Under 70 underground cable | km | 61 | 67 | 76 |
| 95 - 120 underground cable | km | 16 | 11 | 6 |
| 150 - 185 underground cable | km | 10 | 8 | 5 |

When renewing overhead lines from forest with cabling strategies A and B there is need for more cables with larger cross-sectional diameter than with renewing strategy C as seen in table 7.2. The difference is caused by the locations where these cablings are done. Strategies A and B are more focused on areas where there are more customer than in the areas of strategy C. Therefore renewed lines in strategies A and B need to transfer more energy and larger diameter cables are more needed.

The amount of secondary substations to be renewed vary depending on the renewing strategy. In scenario A there were 86, in scenario B 71 and in scenario C 63 secondary substations to be renewed. Most of the substations are 2-polemounted substations and approximately one fourth are 1-polemounted substations in every scenario. Scenarios A and B also have 4-polemounted substations. Every 1-polemounted and 50% of 2-polemounted substations are replaced with satellite substations. The remaining substations are replaced by pad-mounted substations with disconnectors. More accurate information is shown in appendix I. Scenarios A and B have more substations for renewing because prioritization criteria in both scenarios are more customer-oriented. In addition, cabling in scenario C is located further from primary substations than in scenarios A and B.

In all three scenarios the amount of removed overhead lines is approximately the same. They differ from each other mainly in the cross-sectional diameter of overhead lines and the amount of renewed pole mounted secondary substations. Main interest in removed network is repurchase value and average age of removed network from which it is possible

to calculate RAV that is lost in premature renovation. Table 7.3 shows average age, RV and RAV in different scenarios.

Table 7.3 Key figures of removed network.

| | A: Prioritization by COC | B: Maximizing MDP Customers | C: Minimizing excavation costs |
|---|---|---|---|
| Average age [a] | 31 | 29 | 28 |
| RV [k€] | 3 473 | 3 374 | 3 326 |
| RAV [k€] | 781 | 928 | 998 |

The location of cabling in relation to consumption and customers has a great impact on investment cost. When renewing is located closer to primary substations, large amount if customers or consumption, more secondary substations are needed and cross-sectional diameter of cables need to be wider. This combined with excavation costs increases investment costs.

## 7.2 Reliability

Normal state reliability is nowadays an important part of electricity distribution business. Large amounts of cabling are meant to increase supply security, but they also increase normal state reliability. Therefore studying how different renewing strategies impact normal state reliability is important. Improved reliability has a positive effect also on revenue in the regulation model. Changes in reliability are compared against the base case described earlier in chapter 7.

Trimble NIS RNA-tool was used for reliability calculations. RNA calculation was made for every scenario so that the results represents normal state reliability after investments. Most important reliability indicators for base case and different scenarios are presented in table 7.4.

Table 7.4 Reliability indicators for the base case and different scenarios.

| | Base case | A: Prioritization by COC | B: Maximizing MDPR Customers | C: Minimizing excavation costs |
|---|---|---|---|---|
| Customers | 9 279 | 9 279 | 9 279 | 9 279 |
| Faults [per year] | 99 | 86 | 86 | 84 |
| Sum of time without electricity [min/a] | 17 516 | 15 470 | 15 385 | 15 017 |
| CAIDI | 1,43 | 1,37 | 1,44 | 1,44 |
| SAIDI | 7,01 | 5,78 | 6,05 | 6,48 |
| SAIFI | 4,89 | 4,20 | 4,21 | 4,50 |
| Energy not supplied [kWh] | 88 994 | 74 246 | 79 836 | 84 391 |
| COC [€] | 1 184 520 | 986 826 | 1 060 460 | 1 121 453 |

In reliability indicators SAIFI, SAIDI and CAIDI smaller values represents better reliability. Scenario C decreases most faults even tough renewing amounts are approximately the same in in every scenario. This can be explained by forest density. RNA parameters were set so that fault frequency is dependent on density of the forest that overhead line is located in. Scenario C has less faults per year than scenarios A and B because renewed overhead lines in scenario C were located in denser forest.

Even though fault frequency and sum of time without electricity are higher in scenario A, other reliability indicators in scenario A are better. Scenario A is naturally best on reducing COC, even though its fault amounts are higher than scenario in C. Customer outage cost consists of fault amounts, interruption times and average power of customers. From energy not supplied can be seen that average power together with outage time has a significant impact on customer outage cost.

Overhead lines that are renewed in scenario C were located more at the end of feeders than in scenarios A and B. More effecting reason for weaker reliability enhancements were caused by greater amount of network automation located before renewing investments in scenario C than in other scenarios. Therefore faults that scenario C removed would have not been experienced by so many customers than in other scenarios. In scenario C the north

side of the network was left almost without cabling. This is why in scenario C effects of cabling on reliability indicators are a lot smaller than scenarios A and B. Large amount of cablings in scenario A were located in long feeders. In long feeders cabling in the right places can decrease COC very efficiently.

### 7.3 Supply security in major disturbance

In major disturbance in supply security point of view all three scenarios have one thing in common. They all fulfill the 36 hour interruption time limit. However, final networks of all scenarios behaves differently in a major disturbance.

Scenario B maximizing MDP customers is good at fulfilling its main purpose. It decreases strongly the peak value of customers without electricity. It creates many major disturbance proof feeding points in to the network. Even without automation, in a major disturbance it is fast to restore electricity supply to these points and customers before them. If circuit breakers were to be added, customers before these points wouldn't experience any interruptions from major disturbance.

In scenario A prioritization by COC renewing was more scattered than in other scenarios. Scenario a holds weatherproof line sections that the feeding network contains line sections that are not weather proof due scattered cabling locations. In a major disturbance there would be a lot of network without electricity including weather proof structures. This slows down fault localization and increases fault fixing times.

As mentioned before, minimizing excavation costs creates long continuous cabling routes. Therefore some feeders are almost fully cabled and others are left out from cabling. In scenario C renewing focused mostly into the southern part of the network. This left the north side more exposed to falling trees than in other scenarios. This means that supply security spreads unevenly to the networks. On the plus side, in scenario C fault prone area is more compact than in other scenarios. This way faults that will occur in a major disturbance are closer to each other and fault fixing times decrease due shorter distances that fitters need to travel from fault location to another.

Scenario B has the most beneficial renewing strategy in the major disturbance point of view. It is the most efficient to secure customers from major disturbance. Even if scenario C creates few feeders that are almost fully weatherproof, it is not so effective to decrease the peak of customers without electricity as scenario A. In major disturbance scenario A would be the most difficult to control and it's not so sufficient to fix faults in scenario A due difficulties it creates for fault localization.

### 7.4 Profitability of investments

Improvements that these scenarios make to reliability and supply security are important for the customer point of view. For DSOs profitability of investments is also important. Profitable investments enables DSOs to develop electricity distribution network and collect revenue from the business. Investment profitability calculations are made as described in chapter 4.2.2. Some of the more complex factors and assumptions in profitability calculation are described more specifically.

Interest of 10-year Finnish government bond has been strongly decreasing over the past few years. This has also a great effect on regulator WACC witch was 3,03 % in the year 2014, when for example in year 2010 WACC was 5,26 %. On the other hand corporate tax rate has drop from 26% to 20% in the same time period, this increases regulated WACC. Due future uncertainties of 10-year Finnish government bond and other factors in regulated WACC, an average WACC of 4,56 % from years 2009 to 2014 is used to calculate reasonable return of capital.

RAV-write-down can be made from each scenario due the supply security incentive. This means that the differences in average age and NPV of removed network can be calculated as positive cash flow for the first year. Repurchase value of removed network is taken into account when change in regulatory straight-line depreciation is calculated.

Maintenance costs for overhead line network consists of scheduled inspections, maintenance and tree clearing. The most dominant part of those is tree clearing, which concerns only overhead lines in the forest. Maintenance costs for cable network are only a

fraction from overhead line network. There inspections and maintenance of substations and cable cabinets are the only costs. Changes in fault fixing costs are not so great as in maintenance or what decreased fault amounts in RNA results indicates. Fault fixing cost per fault is a lot higher in cable network than in overhead line network. The fault fixing cost per fault cancels some of the effects that decreased fault amounts make to total fault fixing costs.

In the fourth regulation period cabling rate effect allowed operational costs true efficiency incentive. Higher cabling rate allows DSOs to have higher ATOTEX. Due complexity of StoNED model used in regulation in the efficiency incentive, ΔATOTEX is calculated as a marginal value for the amount of over headlines replaced by cables. This way it is possible to determine how much ATOTEX changes from one kilometer of cabling. The marginal value of ΔATOTEX for the amount of over headlines replaced by cables is 1,05 k€/km/a. It is uncertain if cabling rate will be effecting ATOTEX in the future as it does in the current regulation period. Therefore the effect of ΔATOTEX is calculated only for four years forward. This represents the regulatory periods in a way that change in cabling rate effects efficiency incentive only for one regulatory period.

Change in customer outage cost is calculated from RNA results presented in table 7.4. In the third regulation period in the regulation model the reference level of customer outage costs ($COC_{ref}$) is calculated as an average from years 2005-2010. In the upcoming regulation period $COC_{ref}$ will be updated. Therefore, in the profitability calculations COC savings are calculated for the next four years which is the length of one regulatory period. This way the timing of these investments corresponding to regulatory periods is not taken into account. On the other hand, in customer perspective, differences in COC savings will be experienced for the whole life time of the network.

The profitability calculation is made using principle introduced in equation (4.5). Investment is calculated take place at year 2014, income and other costs or savings from year 2015 onwards. Lifetime of investment is 44 years. Required rate of return is

determined to be 6,5%. Table 7.5 presents results of profitability calculation discounted to 2014 present value.

Table 7.5 Present values of profitability calculation are discounted to 2014 monetary value. Required rate of return $r$ = 6,5 % and T = 44 a.

| | A: Prioritization by COC | B: Maximizing MDP Customers | C: Minimizing excavation costs |
|---|---|---|---|
| ΔRRC | 4 064 | 3 809 | 3 636 |
| Δdepreciation | 2 313 | 2 097 | 2 017 |
| ΔCOC | 677 | 425 | 216 |
| ΔM | 76 | 76 | 76 |
| ΔATOTEX | 262 | 258 | 263 |
| Security of supply incentive | 964 | 1 080 | 1 136 |
| Investment | -9 130 | -8 718 | -8 405 |
| **Free cash flow / NPV** | **-773** | **-974** | **-1 062** |

The overall profitability of all investments is weak. From the renewing strategies scenario A is the most profitable as shown in table 7.5. NPV tells if the investment is profitable and how profitable it is. When NPV is zero, the investment barely fulfills the profitability level that is set for it. With the required rate of return of 6,5 %, none of these scenarios fulfill profitability demands set for them.

Depreciations and reasonable return on capital have a great impact on profitability of investment, when absolute values are compared. They bring over 70 % of positive cash flow. However, both of them impacts to profitability of investment are the same in relation to investment costs in every scenario.

In the profitability calculation change customer outage cost is an important factor when differences between scenarios are reviewed. Scenario A has a significant advantage from ΔCOC compared to other scenarios.

Security of supply incentive has a great influence on investment profitability in these scenarios. Scenario C has the lowest average age of removed network. Therefore it benefits the most from security of supply incentive compared to other scenarios.

### *7.4.1 Sensitivity analysis*

The Finnish regulatory model has factors that are bounded to variables that cannot be controlled. One of these is WACC in reasonable return on capital. The regulatory model holds different kind incentives that are created control revenue that DSOs can collect. Some of them help to increase and some decrease revenue. For this work interesting incentives or factor in them are WACC, ATOTEX and Security of supply incentive.

The 36 h outage limit in Electricity Market Act causes premature renovation of overhead lines in many cases. When network is renewed before the end of its lifetime, DSO loses significant amount of RAV from the removed network. Security of supply incentive was created to compensate premature renewing investments due the new Electricity Market Act. Security of supply incentive lasts until 2015, but investments to improve security of supply lasts longer. Therefore it is important to evaluate how lack of security of supply incentive effects investment profitability.

WACC has been decreasing drastically over the past few years. Therefore it is good to calculate how different WACC values impact profitability. Figure 7.2 shows how WACC effects profitability of the three studied scenarios together with the lack of security of supply incentive and ATOTEX.

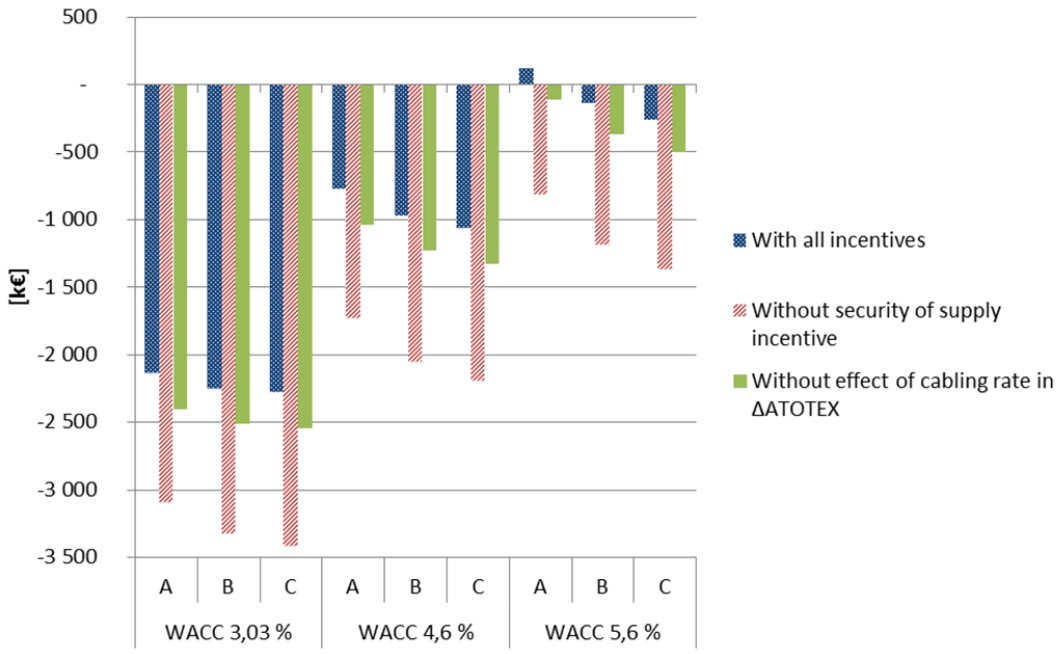


Figure 7.2 NPV of different scenarios with varied WACC and effects of security of supply incentive and change in ATOTEX.

As seen from figure 7.2 investment profitability is on a very poor level in most of the sensitivity scenarios. If WACC stays at the same level as it is in year 2012 WACC = 3,03%, profitability of these investments will decrease strongly. Reasonable return on capital is the most important source of income in the regulation model for DSOs. With WACC level of 5,6 % together with all the existing incentives only scenario A would fulfill the required rate of return that is set in these calculation. If WACC stays as low as it has been for the past years it these scenarios won't be enough profitable to meet required rate of return.

In the studied scenarios security of supply incentive has clearly a significant impact on the profitability as seen in figure 7.2. This is caused by the average age of network. When cabling amounts are as high as the new Electricity Market Act requires, there will be great amounts of network that needs to be renewed prematurely with significant amounts of RAV

left. Without the security of supply incentive premature reinvestments suffer great damage in profitability.

Cabling rate effects ATOTEX. ATOTEX with the effect of cabling rate improves profitability slightly but isn't sufficient to make expensive cabling investments profitable. The lack of ΔATOTEX clearly decreases investment profitability. However, ATOTEX incentive impact on profitability remains fairly constant between the network scenarios.

From the sensitivity analysis can be seen that incentives in the regulation model are very important factors in investment profitability. Without these or other incentives and the significantly higher WACC than current regulatory WACC level, it is impossible to make investment that have sufficient profitability. In addition to WACC, also the security of supply incentive has very significant impact on investment profitability and is crucial for investments that are made for fulfilling new legislative reliability requirements.

### 7.5 Outcome

Scenarios A and B are more profitable than scenario C and they renew network evenly enough between feeders. Scenario A would be chosen to be execution if profitability or normal state reliability were key priorities. But when supply security is in state scenario B would be the best choice for execution. Locations of renewing in scenario B are the most suitable for supply security. It's the most efficient way to reach all the steps required in the new Electricity Market Act.

The prioritization method in scenario C, minimizing excavation costs, drives renewing into unreasonable locations. Cabling behind circuit-breakers in the network doesn't give as good COC savings as cabling in network that doesn't have network automation. Even tough scenario C has the smallest investment cost and greatest security of supply incentive, pour COC savings makes it the worst renewing solution in the study area.

Customer outage costs are in such great role between different scenarios. The prioritization methods for renewing wouldn't cause similar results as this work in other areas due unreasonable renewing locations of scenario C. Therefore renewing methods need to be evaluated in a case by case basis.

# 8. SUMMARY

In Finland the electricity distribution network was built in the rural areas mainly in between 60's and 90's. At that time a lot of overhead lines were built into forest. Therefore in the early 2000's DSOs have mainly focused in normal state reliability when renewing electricity distribution network. Network automation, locating lines on road sides, underground cabling among other techniques have been used. Lately main focus has become supply security. From techniques to improve reliability cabling is the most effective to improve supply security. Due major storms situations in the early 2000's like Tapani and Hannu that caused long outages for customers, longest lasted up to two weeks

New Electricity Market Act was announced in 2013. It orders DSOs to develop their network to improve supply security. The new Electricity Market Act set maximum duration for outages in any situation even major disturbance. These outage limits are six hours for city plan areas and 36 hours for other areas. The new law also set a time table for development where all customers need to be inside maximum outage limitations by 31.12.2028. This causes full-scale cabling in city plan areas. In other areas DSOs have more options to develop their network.

To find out how much overhead lines need to be removed from forest, supply security analysis need to be made. Supply security analysis is based on earlier major disturbances. Main factors in supply security analysis are fault fixing times in major disturbance for MV and LV network, network structure, fault fixing capacity and forest rate of the studied area. In this work Tapani storm is used as a reference storm.

The study area for this work was chosen from Satakunta. It has long feeders that supply large rural area. There is a lot of agricultural activity. Therefore forest rates are not as high as usually in Finland. The study area holds 161 km of MV and 315 km of LV overhead line network in the forest. As a result from the supply security analysis 105 km of MV and 150 km LV overhead lines need to be removed from forest.

This work focused on studying the effects of medium voltage renovation. Main aim in this work was to find tools for prioritizing of overhead lines in MV network to be renewed. Three prioritization methods for choosing renewed line sections. A: prioritizing line sections by customer outage cost they cause, B: maximizing major disturbance proof customers and C: minimizing excavation costs in MV network.

Profitability calculations were made so that they follow calculation methods of the Finnish regulatory model. The results showed that incentives in the regulatory model are very crucial for investment profitability. Security of supply incentive stands out with the compensation of RAV from premature investments caused by the new Electricity Market Act. With current regulatory WACC levels it is impossible to make investments that have sufficient profitability level.

From the prioritization methods A was the most profitable and C had the weakest profitability. Scenario B created the most reasonable network structure in supply security point of view. In the study area customer outage costs made a great difference between different prioritization methods. Scenario C drove renewing into unreasonable locations behind network automation. That caused weaker increase of normal state reliability than in other scenarios. Therefore these prioritization methods need to be evaluated in a case by case basis.

For further studies two interesting topics stood up while making this work. First: How will the networks from these prioritization methods differ in costs and outage times caused by major disturbance? Secondly: How tree clearing and side forest treatment impact on supply security? This is a big question in areas that have problems with snow loads.

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APPENDIX I: Regulatory list prices with investing amounts

| Component Class | unit | unit price € | A: Prioritization by COC | B: Maximizing MDP Customers | C: Minimizing excavation costs |
|---|---|---|---|---|---|
| MV Cables | | | | | |
| Enintään 70 maakaapeli | km | 24520 | 61 | 67 | 76 |
| 95 - 120 maakaapeli | km | 32290 | 16 | 11 | 6 |
| 150 - 185 maakaapeli | km | 37940 | 10 | 8 | 5 |
| LV Cables | | | | | |
| Enintään 25 maakaapeli | km | 7840 | 28 | 28 | 28 |
| 35 - 50 maakaapeli | km | 8970 | 135 | 135 | 135 |
| 70 maakaapeli | km | 11720 | 32 | 32 | 32 |
| 95 - 120 maakaapeli | km | 12890 | 0 | 0 | 0 |
| | | | | | |
| 0,4 ja 20 kV maakaapelit (kaivu) | | | | | |
| Helppo | km | 10120 | 62 | 63 | 73 |
| Normaali | km | 23110 | 9 | 8 | 0 |
| Vaikea | km | 66000 | 2 | 1 | 0 |
| | | | | | |
| Secondary substations | | | | | |
| Kevyt puistomuuntamo | kpl | 9170 | 54 | 44 | 41 |
| Puistomuuntamo, ulkoa hoidettava | kpl | 24540 | 32 | 27 | 22 |
| | | | | | |
| Kaapelijakokaappi, enintään 400 A | kpl | 1390 | 293 | 293 | 293 |

APPENDIX II: Regulatory list prices with removed network

| Component Class | unit | unit price € | A: Prioritization by COC | B: Maximizing MDP Customers | C: Minimizing excavation costs |
|---|---|---|---|---|---|
| MV overhead lines | | | | | |
| Sparrow tai pienempi | km | 20760 | 31 | 33 | 42 |
| Raven | km | 24610 | 18 | 21 | 14 |
| Pigeon | km | 26570 | 14 | 9 | 5 |
| Al 132 tai suurempi | km | 29930 | 7 | 3 | 0 |
| Yleiskaapeli 70 tai pienempi | km | 46170 | 0 | 1 | 0 |
| Yleiskaapeli 95 tai suurempi | km | 48910 | 0 | 0 | 0 |
| Päällystetty avojohto 35 - 70 | km | 30020 | 2 | 1 | 7 |
| Päällystetty avojohto 95 tai suurempi | km | 32160 | 2 | 4 | 4 |
| Muut | km | 20760 | 0 | 0 | 0 |
| LV overhead lines | | | | | |
| AMKA 16 - 25 | km | 15480 | 13 | 13 | 13 |
| AMKA 35 - 50 | km | 16710 | 104 | 104 | 104 |
| AMKA 70 | km | 19480 | 24 | 24 | 24 |
| AMKA 120 | km | 22740 | 0 | 0 | 0 |
| Muut | km | 15480 | 8 | 8 | 8 |
| | | | | | |
| Secondary substations | | | | | |
| 1-pylväsmuuntamo | kpl | 5040 | 22 | 18 | 19 |
| 2-pylväsmuuntamo | kpl | 6700 | 63 | 51 | 43 |
| 4-pylväsmuuntamo | kpl | 7710 | 1 | 2 | 1 |