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Possibilities to Optimize Low Voltage Network Investments in Rural Areas

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Declaration:
Hereby I declare that this doctoral thesis, my original investigation and achievement, submitted for the doctoral degree at Tallinn University of Technology has not been submitted for any academic degree.

Tiit Hõbejõgi ……………….

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TIIT HÕBEJÕGI

TTÜ KIRJASTUS

TABLE OF CONTENTS

LIST OF ORIGINAL PUBLICATIONS

The present doctoral thesis is based on the following publications, which are referred to in the text using Roman numbers I-III:

[I] Ots, M.; Hamburg, A.; Mere, T.; Hõbejõgi, T.; Kisel. E (2016). Impact of price regulation methodology on the managerial decisions of the electricity distribution network company. IEEE ENERGYCON 2016.

[II] Laanetu, M.; Hõbejõgi, T. (2013). Network Quality Indicators and Overview of Longterm Load Forecasting Models. In: 13th International Symposium "Topical problems in the field of electrical and power engineering" : doctoral school of energy and geotechnology. II : in memoriam of professor Juhan Laugis : Pärnu, Estonia, January 14-19, 2013: (Toim.) Zakis, J. Tallinn: Elektrijam, 192 - 196.

[III] Hõbejõgi, T.; Reinberg, A.; Last, K.; Laanetu, M.; Mere, T.; Valtin, J.; Hamburg, A. (2014). Methodology for finding investment sites that can be refurbished from a nearby middle voltage line element instead of using the existing low voltage line corridor. Przeglad Elektrotechniczny, 10, 199 - 202.

[IV] Hõbejõgi, T.; Vill, K.; Valtin, J. (2015). 1 kV distribution system as a cost effective alternative to the middle voltage systems. Przeglad Elektrotechniczny, NR 2/2016.

Copies of publications I-IV are included in Appendix A.

Author's own contribution

The contribution by the author to the papers included in the thesis was as follows:

[I] Tiit Hõbejõgi was the corresponding author. He was responsible for the data collection and analyses.

[II] Tiit Hõbejõgi wrote the paper and was the corresponding author. He was responsible for the data collection and analyses.

[III] Tiit Hõbejõgi wrote the paper and was the main author. He was responsible for the literature overview, calculations and analyses.

[IV] Tiit Hõbejõgi wrote the paper and was the main author. He was responsible for the data collection, calculations and analyses.

INTRODUCTION

The lifespan of distribution networks' infrastructure is very long and investments extremely resource intensive. Even if the investments themselves are not financially feasible, most distribution networks have an obligation to provide a network connection to their customers. Therefore, it is essential to invest as efficiently as possible. Distribution networks are created over a long period of time and the principles that govern these investments can change. Because of that, the original configuration of the distribution network will not always be the most optimal and may become inefficient in providing electricity for nowadays needs. As the network already exists, there are certain restrictions and a perfect network cannot be easily constructed.

This thesis concentrates on how to optimally provide power for those low voltage customers, who are situated furthest from the existing substations and whose network refurbishment is the most expensive. Even though low voltage customers are the focus, both low and middle voltage network optimizations are taken into account, when finding the best solutions.

The current thesis includes a summary chapter and four appended published papers. In the summary chapter, the related author's publications, methods and results are described. The thesis purposes an example for each of the three principal opportunities (optimization of the network configuration, use of other voltage levels or use of other alternatives to the traditional network connection) for minimizing the total lifetime costs (investment and maintenance) for low voltage networks in the rural areas. Rural areas are in focus, because the number of customers there is small and the relative length of the network large. Therefore, large investments are not justified.

Chapter 1 *Current relevance* provides the reasons why this topic was chosen and is based on articles [I] and [II]. In Chapter 2 *Methodology*, examples for all three principal opportunities for network investment optimization are provided:

1. Optimizing existing network configuration;
2. Using 1 kV voltage level for certain network areas;
3. Using off-grid as an alternative to the traditional network connection.

The first opportunity considers the optimization of the existing network configuration. As mentioned above, distribution networks are built over a long period and therefore the resulting configuration is rarely optimal. This thesis provides a method, which helps network analysts to find the most favorable investment sites, by finding non-optimal middle voltage configurations that could be used to decrease underutilized low voltage network. By taking into account the surrounding middle voltage network, this method can find investment sites where renovation costs can be much lower than simple algorithms using only low voltage network would suggest. The objective of this method is to find parts of long low voltage feeds that can be refurbished by building a new substation area from a nearby middle voltage line element (MVLE). Ideally, we can then dismantle a large part of the low voltage line, thereby reducing underutilized network, its maintenance costs and increasing the overall network quality. Because every distribution network has its own principles (which materials and solutions should be used in different situations), only the methodology for finding these sites and not the actual solutions is provided. Although this methodology was initially designed for the Trimble Network Information System, it can also be applied to other information systems. This topic is covered in paper [III].

Secondly, if network configuration cannot be optimized, the distribution network should consider ways to optimize the investment itself. One of these ways is to use other voltage levels, e.g. 1 kV solutions to reduce the overall investment costs. This thesis debates using 1 kV power lines to refurbish the low-voltage feeders of those customers, who currently have a 0.4 kV solution, but are situated too far from the substation, to provide power according to nowadays' standards. In addition, an approach for finding potential investment sites is provided. This topic is covered in paper [IV].

Thirdly, the distribution network should consider other alternatives to the traditional power line construction. This thesis considers off-grid as an example of these alternatives. The meaning of the off-grid can be taken literally: the customer is situated outside the grid. In other words, they have no connection point and are instead connected directly to a power generator. For example, off-grid solutions to water systems can be completed using artesian wells. Power networks usually comprise of a small renewable power plant (e.g. solar battery or wind-mills), a storage battery, an inverter and a diesel generator [1]. Off-grid is not a new concept as there are many places, where providing the traditional connection is impossible (e.g. on small islands or in the mountains). This thesis provides a methodology for the distribution networks to analyze the financial feasibility of off-grid solutions as an alternative to the traditional power line construction. As a simplification, only solar power was considered as the source of renewable energy generation. The use of this optimization opportunity depends a lot on the customer's consumption needs: larger consumption needs means higher cost of the off-grid unit, making it less likely to be feasible.

In Chapter 3 *Results*, the results of testing all three of the opportunities in Elektrilevi OÜ is presented. Elektrilevi OÜ is Estonia's largest distribution network. It distributes power to about 500,000 customers with a total consumption of approximately 6.5 TWh as recorded in 2014. The company manages around 64,000 km of power lines and more than 24,000 substations. Although Elektrilevi OÜ has fifteen 1 kV substation areas that were built mostly in 2008, the use of the solution was discontinued in 2009. As of 2015, there is 1 off-grid test object under evaluation in Elektrilevi OÜ network.

In Chapter 4 *Discussion*, issues arisen during the study are analyzed and the critical assessment of the results is made. Also, further possible studies are provided, that need to be completed to further develop this topic.

The purpose of the thesis

The purpose of this thesis is to propose different possibilities for optimizing low voltage network investments in the rural areas, where the number of customers is small and the relative length of the network large, i.e. where large investments are not justified. The three principal opportunities provided are:

1. Optimizing existing network configuration;
2. Using 1 kV voltage level for certain network areas;
3. Using off-grid as an alternative to the traditional network connection.

The more specific goals of the applicant's doctoral studies were:

1. Provide a methodology for finding possible investment sites where network optimization is possible;
2. Provide an approach for finding investment sites, where using a 1 kV solution would benefit the distribution network;
3. Analyze the positive and negative effects that using 1 kV solution has;
4. Provide a methodology for evaluation of off-grid as an alternative to the traditional network connection.

Contribution of the thesis

This thesis includes theoretical approaches, methodological and practical recommendations for optimization of the low voltage distribution network investments in the rural areas. The originality of the thesis consists in theoretical and practical results.

Theoretical originality of the thesis includes three methodological recommendations for minimizing the total investment cost into low voltage rural networks. Relevant risks to using off-grid solutions have also been presented.

Practical originality of the thesis includes results obtained through employing the proposed methodologies in Elektrilevi OÜ. The results can be used for determining the use of 1 kV and off-grid solutions in different distribution networks. Elektrilevi OÜ has used both the network optimization and off-grid methodology presented in this paper to choose suitable investment sites.

Acknowledgments

Many people have contributed during the years of carrying out my doctoral studies, who deserve to be acknowledged.

Firstly, I would like to express my gratitude to my supervisor Professor Juhan Valtin for the useful comments, remarks and engagement through the learning process of this doctoral thesis. Furthermore, I would like to thank all of the experts from Elektrilevi OÜ for contributing with their time, knowledge and expertise. Special thanks to Professor Arvi Hamburg for keeping the motivation high throughout the period.

Secondly, Tallinn University of Technology and the Doctoral School of Energy and Geotechnology II are gratefully acknowledged for financial support.

Finally, I appreciate the support from my family, friends and especially my wife Helen, who have been understanding and supporting throughout entire process.

LIST OF SYMBOLS

MVLE	Middle Voltage Line Element	
Crit_Dist	If the distance between the substation and connection point is less than Crit_Dist, then this connection point is excluded from the calculations	m
Max_Dist	Maximum distance between connection point and middle voltage line element	m
$P_1(x_1;y_1)$	Coordinates of the starting point of the middle voltage line element	
$P_2(x_2;y_2)$	Coordinates of the ending point of the middle voltage line element	
$P_3(x_3;y_3)$	Coordinates of the connection point	
u	*R*atio, that represents the relative distance between *P* and P_1	
U_n	Nominal line-to-line voltage of the network	V
z_f	Feeder total impedance on the temperature 20^0	Ω
$z_{tk}^{(1)}$	Transformer impedance during one-phase fault	Ω
l	Feeder length	km
z_j	Cable impedance per kilometer	Ω/km
I_l	Load current of the feeder	A
NPV	Net present value	€
C_t	Net cash flow during the period	€
C_0	Initial investment	€
r	Discount rate	
t	Period number	
T	Number of time periods	
C_{0P}	The initial cost of building a power line	€
C_{mv}	Unit cost of building a middle voltage line	€/km
L_{mv}	Length of the middle voltage line	km
C_{lv}	Unit cost of building a low-voltage line	€/km
L_{lv}	Length of the low-voltage line	km
C_S	Unit cost of the substation	€
n_S	Number of substations	
C_{Sw}	Cost of the switching to connect to an existing network or substation	€
E_{Pt}	net expense for the power line alternative for period t	€
E_{MOHL}	Base unit cost for the overhead power line maintenance	€/km
E_{IOHL}	Base unit cost for the overhead power line inspection	€/km
E_{MS}	Base unit cost for substation maintenance	€
E_{IS}	Base unit cost for substation inspection	€
E_D	Base unit cost for deforestation	€/km
E_{EL}	Unit cost for energy loss	€/kWh
L_D	Length of deforestation area for period t	km

W_{EL}	Average energy loss for period t	kWh
CPI	Average change in the consumer price index.	
C_{OO}	The initial cost of building an off-grid solution	€
C_{RG}	Unit cost of the renewable generator	€/kW
C_B	Unit cost of battery bank	€/kW
C_G	Unit cost of the diesel generator	€
C_{IU}	Unit cost of the inverter	€/kW
P	Power consumption of the customer	kW
C_{In}	Installation and other costs €	€
I_{Pt}	Net income for the power line alternative for period t	€
V_t	The amount of electricity consumed for period t	kWh
I_N	Base unit price of network service	€/kWh
THI	Average change in consumer price index	
E_O	Net expense for the off-grid alternative	€
V_{AD}	Average fuel consumption for the diesel generator	l/kWh
E_F	Base cost of the diesel fuel	€/l
i_d	Yearly increase in the diesel price	
E_{Dr}	Base cost for driving to the site	€
V_f	Size of the fuel tank	l
C_{Pt}	Net cash flow of the power line alternative during the period t	€
R_1	The risk of the customer leaving and canceling his/her contract	
R_2	The risk of some of the technology becoming obsolete	
R_3	The risk of vandalism	
R_4	The risk regarding the quality of construction	
C_{Ot}	Net cash flow of the off-grid alternative during the period t	€
R_5	The risk of increased expenses due to small scale integration of the off-grid alternative	
NPV_P	Net present value for the power line alternative	€
NPV_O	Net present value for the off-grid alternative	€

1. CURRENT RELEVANCE

Electricity distribution network companies' activities and managerial decisions depend substantially on the applied regulatory methodology, as described in [I]. However, reduction of costs and the increase of network reliability is always the focus point for all regulatory methodologies.

Figure 1 gives an example about Elektrilevi OÜ. According to a 2013 study by Tallinn University of Technology, about 58% of the power lines is situated in the rural area and is used by only 13% of total customers, who consume only 5% of the total energy [2, 3]. The average number of customers in urban-core is 133 per line kilometer, while the same number in rural areas is only 2.6.

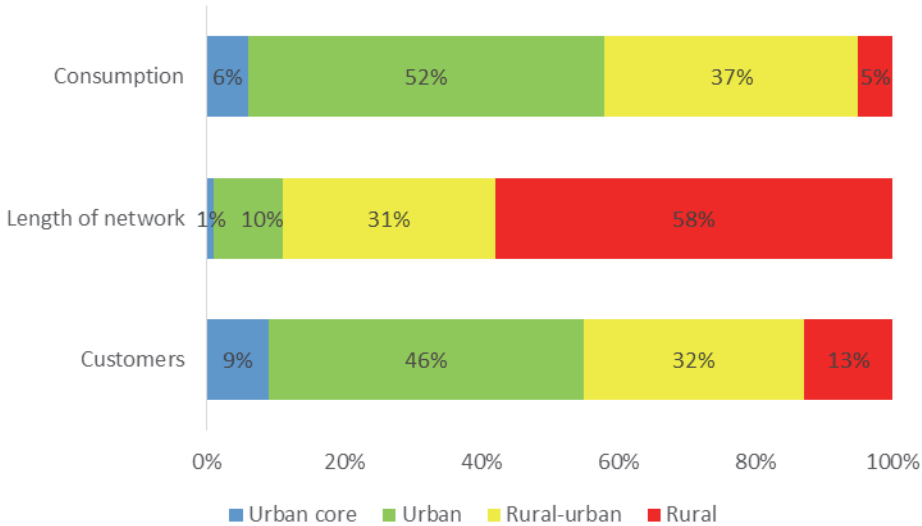

Figure 1 Customers, network length and consumption according to network areas

The price for network service however does not depend on the customer's geographic location. Therefore, in order to provide the same quality of connection to all of its customers, the distribution network would have to focus most of their investments to only a small fraction of the customers who provide only a marginal part of the income. Also, using any of the most used long-term load forecasting methods described in [II] (trend analysis, end-use modeling or econometric modeling [4, 5]) on rural network areas will most likely result in a negative load trend. However, as most of the network is situated in the rural area, most costs and network interruptions also occur there. Therefore, in order to meet the cost and reliability demands put on by the regulator, distribution networks need to optimize their investments in the rural areas.

To conclude, the current relevance of the thesis is related to the constant pressure on distribution networks to reduce costs and increase network reliability as well as their obligation to provide a network connection to all customers. Using the methodology provided in this thesis, distribution networks can optimize their investments in rural areas.

2. METHODOLOGY

This chapter provides an overview of previous studies (Chapter 2.1.) and proposes three distinct methodologies for network investment optimization:

1. Optimizing existing network configuration (Chapter 2.2.);
2. Using 1 kV voltage level for certain network areas (Chapter 2.3.);
3. Using off-grid as an alternative to the traditional network connection (Chapter 2.4.).

The methods provided in this chapter complement each other, but can also be applied separately. These methods work best in distribution networks that cover rural areas, where the number of customers is small and the relative length of the network large, i.e. where large investments are not justified.

2.1. Overview of previous studies

As of the writing of this thesis, there are already many studies that have discussed topics similar to this work.

Firstly, previous studies on the optimization of network investments have:

- Discussed problems of simulation models for modernization of regional LV and MV distribution networks and showed a computational algorithm for the needs for the network modernization [6].
- Discussed various methods of economic analysis of cross-country power networks and presented a modified variant of the annual cost method and the costs of cross-country network unreliability [7].
- Presented a method based on evolutionary strategies [8] and dynamic programming optimization [9] for designing distribution networks.
- Discussed the mixed-integer programming and the evolutionary programming methods of distribution network system planning [10].

The method for optimizing existing network configuration discussed in Chapter 2.2. is also designed for optimal solutions in the investments for the regional LV and MV distribution networks, but uses an approach previously overlooked. To conclude, previous studies have mostly concentrated on middle or high voltage networks, not low voltage.

Secondly, there is also some previous research on 1 kV systems. 1 kV low-voltage systems became popular at the start of this century. Suur-Savon Sähko OY, a Finnish distribution network [11], built the first 1 kV system known to the authors in 2001. Because of that, Lappeenranta University of Technology did most of the research on the technical and economic evaluation of 1 kV systems in distribution networks in 2003-2007. There are several master's thesis and at least one PhD thesis on this topic [12, 13, 14].

Most of the research done on 1 kV systems studies the benefits of refurbishing short low-loaded 20 kV overhead power lines that are underutilized, with 1 kV systems. Some studies also evaluate the financial feasibility of the 1 kV systems compared to other alternatives for increasing network reliability [15, 16, 17, 18].

Few articles on the topic have been published after 2009. However, some interest has resurfaced in the Swedish network company Vattenfall Eldistribution AB. An article by D. Söderberg and H. Engdahl studies the possibility of using 1 kV systems for providing power for electric vehicle charging stations and households in the rural areas. This topic is important because the growing use of electrical cars and the ever higher quality standards for household applications increases the pressure on the distribution networks [19]. In his 2013 article [20], D. Söderberg analyses the necessary parameters for transformers operating in the 1 kV system.

To conclude, the previous research on 1 kV systems concentrates on how to use it to optimize middle voltage network, while this paper evaluates its use in low voltage areas.

Thirdly, the research on distributed generation and off-grid units is mostly divided into two. Most of the research done this far has focused on how to integrate distributed generation units into the network. Some of the examples are:

- Intelligent control of a grid-connected wind-photovoltaic hybrid power systems [21].
- The future of low voltage networks: Moving from passive to active [22].
- Optimal PV–FC hybrid system operation considering reliability [23].

In addition, there is a lot of research on the effectiveness of the off-grid solutions. Some examples of these studies are:

- Reliability and management of isolated smart-grid with dual mode in remote places: Application in the scope of great energetic needs [24].
- Study on stand-alone power supply options for an isolated community [25].

However, there seems to be no study on how to use off-grid solutions to optimize the investments of the distribution network itself, which is the main topic of the third methodology provided in this paper. The main reason for this might be that currently most distribution networks are forbidden to generate electrical power, except to cover their electricity losses.

2.2. Optimizing existing network configuration

This method helps network analysts find the most favourable investment sites, by finding non-optimal middle voltage configurations that can be effectively used to decrease underutilized low voltage low voltage network. By taking into account the surrounding middle voltage network, this method can find investment sites where renovation costs can be much lower than simple algorithms using only low voltage network would suggest. The objective of this method is to find parts of long low voltage feeds that can be refurbished by building a new substation area from a nearby middle voltage line element (MVLE). Ideally, we can then dismantle a large part of the low voltage line, thereby reducing underutilized network and increasing the overall network quality.

The overall optimization process is depicted in Figure 2 (starting with yellow and ending with blue).

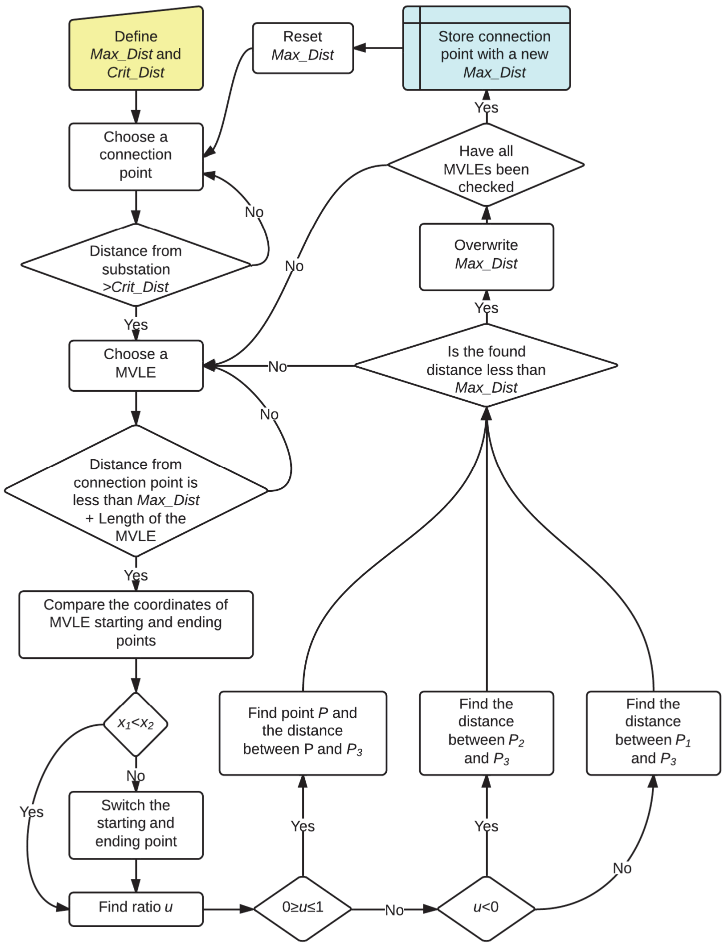

Figure 2 Schema depicting the overall process

Firstly, we exclude all connection points that are closer to their subsequent substation than the critical distance *Crit_Dist*, using the length of the existing low voltage line.

Secondly, we find those connection points, where the closest MVLE is closer than desired distance *Max_Dist*. MVLE can be any middle voltage cable or overhead line part, which begins (and ends) with a pole, switchboard or a turning point for a cable line.

Thirdly, we need to include some background information for suitable connection points: *x* and *y* coordinates (latitude and longitude), connection point ID-code (used to distinguish different connection), size of the main fuse, yearly electrical energy consumption, name of the substation and the feeder.

Fourthly, we find the shortest distance between the connection points and the nearest MVLEs, using connection point coordinates and the start and end coordinates of the MVLEs. Finding the distances of all the MVLEs from all the connection points would be too resource consuming. To counter this problem, we compare the coordinates of connection point $P_3(x_3;y_3)$ and MVLE starting point $P_1(x_1;y_1)$. We only calculate the exact distance if the distance is less than the sum of our desired distance *Max_Dist* and the length of the MVLE. We use this sum because the closest part of the MVLE can just as well be the ending point.

We find this distance using the theory of distance between a point and a straight [26]. This straight passes through the starting point $P_1(x_1;y_1)$ and ending point $P_2(x_2;y_2)$ of our MVLE. Perpendicular for straight P_1P_2, that passes through $P_3(x_3;y_3)$ (the connection point), intersects with the straight passing through MVLE P_1P_2 in point $P(x;y)$ (Figures 3 and 4). The positioning of point P can be calculated using formula 2.2.1.

$$P = P_1 + u \cdot (P_2 - P_1), \qquad 2.2.1$$

where

u – ratio, that represents the relative distance between P and P_1.

If point P is situated on straight P_1P_2, then the distance between P_1P_2 and P_3 equals the distance between P and P_3 and $0 \leq u \leq 1$ [26]. The dot product of two orthogonal vectors equals to zero, therefore:

$$(P_3 - P) \cdot (P_2 - P_1) = 0, \qquad 2.2.2$$

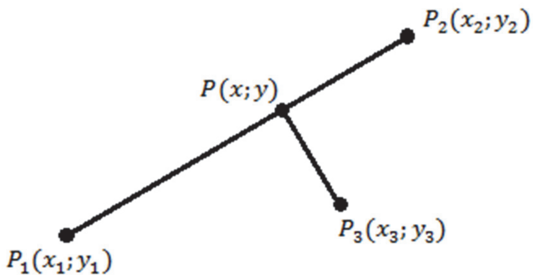

Figure 3 Distance between P3 and P1P2 if 0≤u≤1

We replace P using formula 2.2.1:

$$\left[P_3 - P_1 - u \cdot \left(P_2 - P_1\right)\right] \cdot \left(P_2 - P_1\right) = 0, \qquad 2.2.3$$

Using formula 1.2.3, we can find ration u (formula 2.2.4):

$$u = \frac{\left(x_3 - x_2\right) \cdot \left(x_2 - x_1\right) + \left(y_3 - y_2\right) \cdot \left(y_2 - y_1\right)}{\left(x_2 - x_1\right)^2 + \left(y_2 - y_1\right)^2}, \qquad 2.2.4$$

We can find the coordinates $(x;y)$ for point P by replacing u in formula 2.2.1 (formula 2.2.5).

$$\begin{aligned} x &= x_1 + u \cdot \left(x_2 - x_1\right) \\ y &= y_1 + u \cdot \left(y_2 - y_1\right)' \end{aligned} \qquad 2.2.5$$

Because MVLE are parts with a definite length, then we also need to consider situations where point P is situated outside MVLE and u<0 or u>1.

Figure 4 depicts a line with a MVLE part P_1P_2. The distance between the straight passing through MVLE part P_1P_2 and our connection point P_3 is not the same as the distance between MVLE P_1P_2 and connection point P_3. In this case, the distance we are looking for is either the distance between P_1 and P_3 or P_2 ja P_3.

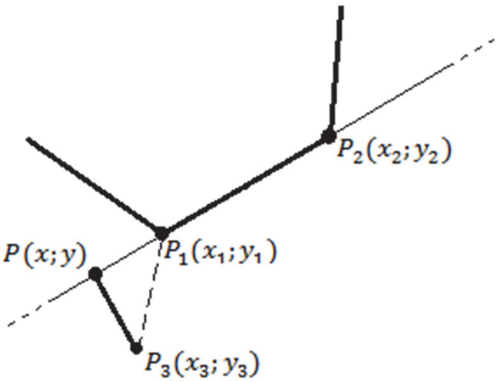

Figure 4 Distance between P3 and P1P2 if u<0

The distance between P_1 and P_3 can be found with formula 2.2.6 [26].

$$P_1P_3 = \sqrt{(x_3 - x_1)^2 + (y_3 - y_1)^2}\ , \qquad 2.2.5$$

where

$P_1(x_1;y_1)$ – MVLE starting point;

$P_3(x_3;y_3)$ – connection point.

In order to find out our current situation, we evaluate the corresponding u ratio. If $0 \geq u \leq 1$, then point P is situated on MVLE part P_1P_2 and the distance we are looking for is PP_3. If u<0, then we have to find the distance between P_1 (MVLE starting point) and P_3 (connection point). If u>1, then we have to find the distance between P_2 (MVLE ending point) and P_3 (connection point).

This method only works if the x-coordinate of the starting point P_1 of MVLE is smaller than the x-coordinate of the ending point of MVLE ($x_1<x_2$). If this is not the case, we need to switch the coordinates of our starting and ending points before using the method. Also for the same reasons if $x_1=x_2$ and $y_1<y_2$, then we have to switch the y-coordinates of our starting and ending points before using the method.

2.3. Using 1 kV solutions in the rural areas

If configuration cannot be optimized (Chapter 2.2.), large investments are needed. This chapter debates on the use of 1 kV system as a cost-effective investment solution in the rural areas and provides an approach for finding potential investment sites. This chapter uses Elektrilevi OÜ's network standards.

Because 1 kV solutions are not standard in Elektrilevi OÜ, building a completely new power line will most likely be just as expensive if not more than building a middle voltage power line. Therefore, only those feeders, where the existing poles can be used will be under evaluation. In order to calculate the maximum length of these feeders, AMKA-type aerial bundled cable will be used. The standard dimensions and resistances for AMKA are known [27]. Increasing the cross-section of the cable, the weight also increases, meaning that the existing poles may also need replacement, increasing the investment costs.

One of the restricting factors of the length of the feeder is the tripping time of a fuse situated on the start of the feeder. In Elektrilevi OÜ, usually gG-type fuses are used for feeder overcurrent and short-circuit protection in MV/LV substations. According to the standard IEC 60364-4-41, the maximum allowable tripping time during one-phase fault is 5 seconds. Minimum one-phase short-circuit current (in temperature 40^0 C and a coefficient for voltage 0.95 as stated in the standard IEC 60909-0) can be calculated according to equation 2.3.1:

$$I_k^{(1)} = \frac{0{,}95U_n}{\sqrt{3}\left(2{,}16z_f + z_{tk}^{(1)}\right)}, \qquad 2.3.1$$

where

U_n – nominal line-to-line voltage of the network (V);

z_f – feeder total impedance on the temperature 20^0 (Ω);

$z_{tk}^{(1)}$ – transformer impedance during one-phase fault (Ω).

As the standard IEC 60269 states minimum short-circuit current for gG-type fuses and cable impedances per kilometer are known, the maximum length l of the feeder in km-s can be calculated according to equation 2.3.2:

$$l = \frac{1}{2{,}16z_j}\left(\frac{U_n}{\sqrt{3}I_{kmax}^{(1)}} - z_{tk}^{(1)}\right), \qquad 2.3.2$$

where

l – feeder length (km);

z_j – cable impedance per kilometer (Ω/km).

Transformer impedances during one-phase fault for Yzn vector group transformers mostly used in ELV network are presented in [28]. Another important restriction is the maximum allowable voltage drop along the feeder at nominal load. In ELV, the maximum admissible voltage drop used for designing and construction of new power lines is 5%.

In practical calculations, the equation 2.3.3 is used for estimating the maximum voltage drop $\Delta u_{\%}$ of a feeder:

$$\Delta u_{\%} = \frac{\sqrt{3}I_l z_j l}{10U_n}, \qquad 2.3.3$$

where

I_l – load current of the feeder (A);

U_n – nominal line-to-line voltage of the system (kV).

As the maximum admissible voltage drop 5% is known, the length of the feeder can be calculated using equation 2.3.4:

$$l = \frac{50U_n}{\sqrt{3}I_l z_j}, \qquad 2.3.4$$

Maximum admissible feeder length is determined by stricter criterion of both as described above. Using this method, it is possible to calculate the maximum length of the feeder (Figure 5).

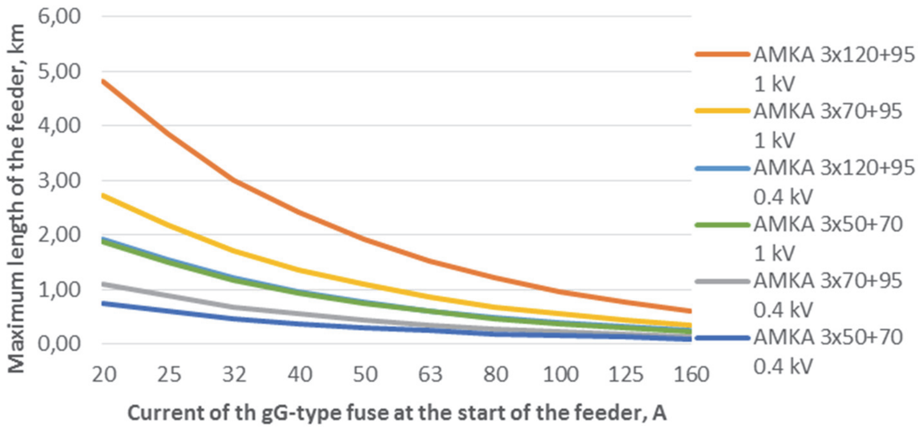

Figure 5 Maximum length of the feeder depending on nominal current of the fuse and dimensions of the aerial cable

It appears that using AMKA 3x120+95 on 0.4 kV has approximately the same restrictions as using AMKA 3x50+70 on 1 kV. Therefore, only AMKA 3x70+95 on 1 kV and AMKA 3x120+95 on 1 kV will be used in the evaluation.

To calculate the financial benefits of using 1 kV systems, we use the net present value (NPV) method, which is used in capital budgeting to analyze the profitability of an investment or project. NPV can be calculated by using equation 2.3.5:

$$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_0, \qquad 2.3.5$$

where
NPV – Net present value (€);
C_t – Net cash flow during the period (€);
C_0 – initial investment (€);
r – discount rate;
t - period number;
T – number of time periods.

The initial investment depends on the length of the power lines and number of substations used and can be calculated using equation 2.3.6:

$$C_{0P} = C_{mv} \times L_{mv} + C_{lv} \times L_{lv} + C_S \times n_S + C_{Sw}, \qquad 2.3.6$$

where
C_{0P} – the initial cost of building a power line (€);
C_{mv} – unit cost of building a middle voltage line (€/km);
L_{mv} – length of the middle voltage line (km);
C_{lv} – unit cost of building a low-voltage line (€/km);
L_{lv} – length of the low-voltage line (km);
C_S – unit cost of the substation (€);

n_S – number of substations;
C_{Sw} – cost of the switching to connect to an existing network or substation (€).

Net income does not differ regardless of the solution provided to the customer. Therefore, net cash flows equal net expense that can be calculated using equation 2.3.7.

$$E_{Pt} = \big((E_{MOHL} + E_{IOHL}) \times L_{lv} + (E_{MS} + +E_{IS}) \times n_s + E_D \times L_D + E_{EL} \times W_{EL}\big) \times (1 + CPI)^t, \quad 2.3.7$$

where
E_{MOHL} – base unit cost for the overhead power line maintenance (€/km);
E_{IOHL} – base unit cost for the overhead power line inspection (€/km);
E_{MS} – base unit cost for substation maintenance (€);
E_{IS} – base unit cost for substation inspection (€);
E_D – base unit cost for deforestation (€/km);
E_{EL} – unit cost for energy loss (€/kWh);
L_D – length of deforestation area for period t (km);
W_{EL} – average energy loss for period t (kWh);
CPI – average change in the consumer price index.

The alternative that provides the higher NPV is financially more feasible. The useful lifetime of power lines is 40 years in the calculations of this thesis.

2.4. Off-grid as an alternative to the traditional network connection

In addition to finding the best alternative for the traditional power line construction, the distribution network should also consider other alternatives. This chapter concentrates on off-grid, as a long-term alternative to the power line construction. Net present value (equation 2.3.5) is again the best method for evaluation between power line construction and off-grid.

The formula to calculate the initial cost for the power line construction is already presented (equation 2.3.6). The initial cost of building the off-grid alternative is based on the power consumption needs of the customer and can be calculated using equation 2.4.1. The average lifetime of the off-grid unit is approximated to 20 years, which is half of the useful lifetime of the power lines. Therefore, to compare the two alternatives, two cycles of the off-grid alternative will be compared to one cycle of the power line construction.

$$C_{0O} = (C_{RG} + C_B + C_G + C_{IU}) \times P + C_{In}, \quad 2.4.1$$

where
C_{0O} – the initial cost of building an off-grid solution (€);
C_{RG} – unit cost of the renewable generator (€/kW);
C_B – unit cost of battery bank (€/kW);
C_G – unit cost of the diesel generator (€);
C_{IU} – unit cost of the inverter (€/kW);
P – power consumption of the customer (kW);
C_{In} – installation and other costs (€).

The first part of the net cash flows is net income. The Estonian pricing model is used in this paper. The customer pays a total energy price consisting of three parts: price for generating the electricity, price for the network service and the renewable energy fee and excise [29].

In case of the power line alternative, the distribution network receives all three parts of the total energy price but has to pay for the generation of electricity to a third party who actually generated it and the renewable energy fee to the state. Therefore, for the power line alternative, the net income for a certain period equals the price of network service for that period (equation 2.4.2). We assume that the average price increase follows the changes in consumer price index.

$$I_{Pt} = V_t \times I_N \times (1 + THI)^t, \qquad 2.4.2$$

where

I_{Pt} – net income for the power line alternative for period t (€);
V_t – the amount of electricity consumed for period t (kWh);
I_N – base unit price of network service (€/kWh);
THI – average change in consumer price index.

Because the off-grid alternative generates the electricity on the spot, the distribution network can retain the price of generating the electricity, assuming that it can make the necessary changes in the regulation. In addition, since part of the energy generated is renewable, the distribution network is eligible to receive the renewable energy subsidy [30]. The change in the price for generating the electricity can be estimated using the Electricity Nordic DSFuture prices [31]. The renewable energy subsidy is constant in the calculations used in this paper, as it is extremely difficult to predict its trend. Equation 2.4.3 shows the net income calculation for the off-grid alternative.

$$I_{Ot} = (I_E \times (1 + i_e)^t + I_N \times (1 + THI)^t + I_R \times (1 - V_G)) \times V_t, \qquad 2.4.3$$

where

I_{Ot} – net income for the off-grid alternative for period t (€);
I_E – base unit price of generating the electricity (€/kWh);
i_e – yearly increase in the electricity price;
I_R – renewable energy subsidy unit price (€/kWh);
V_G – percentage of energy generated with the diesel generator.

The net expense is the second part of the net cash flows. Because the middle voltage power lines use underground cables, it has no maintenance or inspection costs. Low voltage power lines and substations, however, have to be periodically inspected and maintained. In Estonia, the typical period for maintenance and inspection is five years. If the power lines pass through a forested area, there is also a deforestation cost, which is also periodic and as a simplification occurs every five years. On the 40th year there is no periodic cost, as the power line should be either dismantled or refurbished at the end of its useful lifetime. The change in the periodic costs follows the construction cost index. Equation 2.3.7 shows the net expense for the power line alternative.

Solar panels need very little maintenance and only need to be cleaned a couple of times a year (especially in case of heavy snows). Nowadays battery banks and generators also need very little maintenance and what little is needed can be completed during the refueling process. Because of the routine refueling, there is also no need for additional inspections and the inspection cost for off-grid alternative can be approximated to zero.

There are four factors affecting the refueling cost: power generated through the diesel generator, average fuel consumption, the cost of the fuel and the cost of transportation to the site. Crude Oil Brent Future Prices should be used as a reference for diesel fuel price changes. The price increase for the future prices is fixed on 0.6 % each month for the last three years presented [32]. Therefore, an average yearly increase of 7.4 % in the price of diesel fuel will be used. This change is also very similar to the average change in the Brent Crude Oil prices for the past 45 years [33]. Equation 2.4.4 shows the net expense for the off-grid alternative.

$$E_O = V_G \times V_t \times V_{AD} \times (E_F \times (1 + i_d)^t + \frac{E_{Dr}}{V_f} \times (1 + THI)^t), \qquad 2.4.4$$

where
E_O – net expense for the off-grid alternative (€);
V_{AD} – average fuel consumption for the diesel generator (l/kWh);
E_F – base cost of the diesel fuel (€/l);
i_d – yearly increase in the diesel price;
E_{Dr} – base cost for driving to the site (€);
V_f – size of the fuel tank (l).

As off-grid is fundamentally different from the traditional power line construction, some additional risks should be taken into account for calculating NPV for either alternative.

There are a total of four risks identified by the authors, that affect the power line construction alternative: the risk of the customer leaving and canceling his/her contract, the risk of some of the technology becoming obsolete, the risk of vandalism and the risk regarding the quality of construction. The first two affect the net income only, because the power lines cannot be dismantled and used in other places. The last two can be mitigated through insurance, which is a periodic cost that is based on the initial cost of the power lines. The added risk will adjust the net cash flows for the power line construction, resulting in equation 2.4.5:

$$C_{Pt} = \frac{1}{(1+r)^t} \times (\frac{V_t \times I_N \times (1+THI)^t}{(1+R_1+R_2)^t} - \big((E_{MOHL} + E_{IOHL}) \times L_{lv} + (E_{MS} + E_{IS}) \times n_s + E_D \times L_D\big) \times (1 + CCI)^t - (C_{mv} \times L_{mv} + C_{lv} \times L_{lv} + C_S \times n_S + C_{Sw}) \times (R_3 + R_4)), \qquad 2.4.5$$

where
C_{Pt} – net cash flow of the power line alternative during the period t (€);
R_1 – the risk of the customer leaving and canceling his/her contract;
R_2 – the risk of some of the technology becoming obsolete;
R_3 – the risk of vandalism;
R_4 – the risk regarding the quality of construction.

The off-grid alternative has the same risks as the power line alternative, but the first two affect both the net income and the net expense, as the system can be dismantled and installed for other customers. In addition, the added risk of increased expenses due to small scale integration will adjust the net cash flow for the off-grid alternative, resulting in equation 2.4.6.

$$C_{Ot} = \frac{1}{(1+r)^t \times (1+R_1+R_2)^t} \times ((I_E \times (1+i_e)^t + I_N \times (1+THI)^t + I_R \times (1-V_G)) \times V_t - V_G \times V_t \times V_{AD} \times (E_F \times (1+i_d)^t + \frac{E_{Dr}}{V_f} \times (1+THI)^t) \times (1+R_5) - ((C_{SB}+C_B+C_G+C_{IU}) \times P + C_{In}) \times (R_3+R_4)), \qquad 2.4.6$$

where

C_{Ot} – net cash flow of the off-grid alternative during the period t (€);

R_5 – the risk of increased expenses due to small scale integration of the off-grid alternative.

Using the aforementioned equations the finalized equation for calculating the NPV for the power line alternative is presented in equation 2.4.7:

$$NPV_P = \sum_{t=1}^{T} \frac{1}{(1+r)^t} \times (\frac{V_t \times I_N \times (1+THI)^t}{(1+R_1+R_2)^t} - \big((E_{MOHL}+E_{IOHL}) \times L_{lv} + (E_{MS}+E_{IS}) \times n_s + E_D \times L_D\big) \times (1+CCI)^t - (C_{mv} \times L_{mv} + C_{lv} \times L_{lv} + C_S \times n_S + C_{Sw}) \times (R_3+R_4)) - (C_{mv} \times L_{mv} + C_{lv} \times L_{lv} + C_S \times n_S), \qquad 2.4.7$$

where

NPV_P – net present value for the power line alternative (€).

Using the aforementioned equations the finalized equation for calculating the NPV for the off-grid is presented in equation 2.4.8:

$$NPV_O = \sum_{t=1}^{T} \frac{1}{(1+r)^t \times (1+R_1+R_2)^t} \times ((I_E \times (1+i_e)^t + I_N \times (1+THI)^t + I_R \times (1-V_G)) \times V_t - V_G \times V_t \times V_{AD} \times (E_F \times (1+i_d)^t + \frac{E_{Dr}}{V_f} \times (1+THI)^t) \times (1+R_5) - ((C_{SB}+C_B+C_G+C_{IU}) \times P + C_{In}) \times (R_3+R_4)) - ((C_{SB}+C_B+C_G+C_{IU}) \times P + C_{In}), \qquad 2.4.8$$

where

NPV_O – net present value for the off-grid alternative (€).

Again, the alternative that provides the higher NPV is financially more feasible.

3. RESULTS

All three of the methods were tested in Elektrilevi OÜ distribution network and the results are provided in this chapter. These result provide an overview of the potential of these methods, as the costs used in the calculations present the price level in Estonia at the time of the writing of this thesis.

3.1 Optimizing existing network configuration

The query that supports the methodology was written in SQL query language and the query was run in Oracle SQL Developer software. Oracle SQL Developer is a free integrated development environment that simplifies the development and management of Oracle Database [34].

3.1.1. Testing the methodology

In order to reduce the sample size, the following restrictions were used:

- *Crit_Dist* = 1500 m;
- *Max_Dist* = 100 m.

Using these restrictions, a total of 92 connection points were found on a total of 78 feeders. The location of these connection points is shown in Figure 6 (connection points which are located close to each other are displayed as a single dot). This sample size was considered optimal for an initial testing on the basis of expert judgment, taking into account the budget size reserved to test the methodology. In order to increase the sample size, we should start with increasing the *Max_Dist* component as the increase in the solution cost would be rather insignificant.

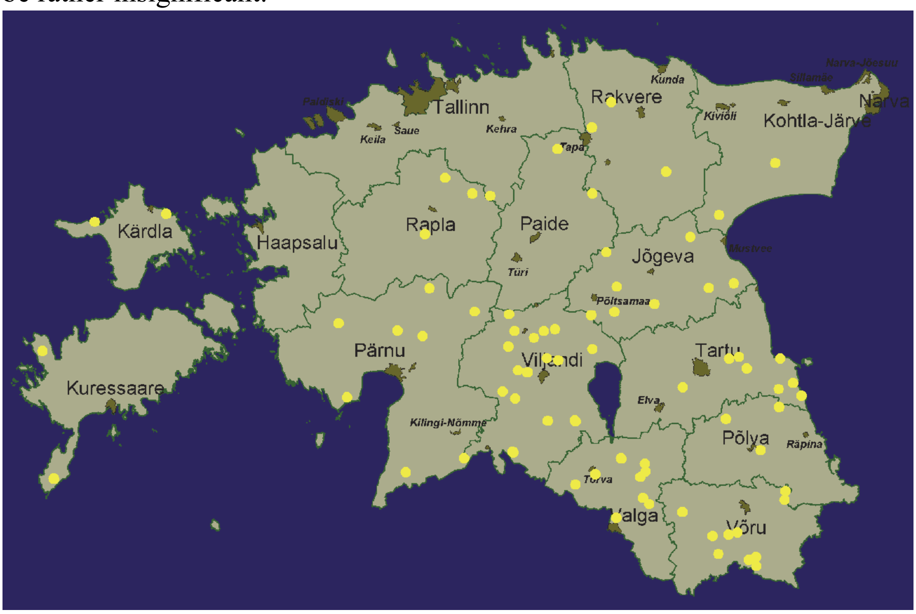

Figure 6 Connection points found by applying the proposed Methodology

Figure 6 shows that the majority of the connection points found are located in the south-eastern region. Generally, this is in rural region where consumption is rather fading and, therefore, large-scale investment does not have perspective. Therefore, it is necessary to invest optimally, which this methodology strongly supports.

All found feeders were further examined to ensure that:

- Investment is sensible;
- There is no error in the data;
- They not currently being refurbished.

Investment is considered not sensible, if there is currently no valid network contract or the last year's electrical consumption was 0 kWh. It is not clear whether the consumption in these connection points will recover or if the connection point vanishes completely (e.g. with the old homestead). Five feeders were left out because of zero consumption. Also, after completing finalized investment solutions, five feeders were considered without long-term perspective because of changing MV network.

After further examination, 47 solutions were sketched to refurbish a total of 48 feeders. Two feeders are being refurbished with a single solution because they were located side by side. The diagram of found feeder's distribution is shown in Figure 7.

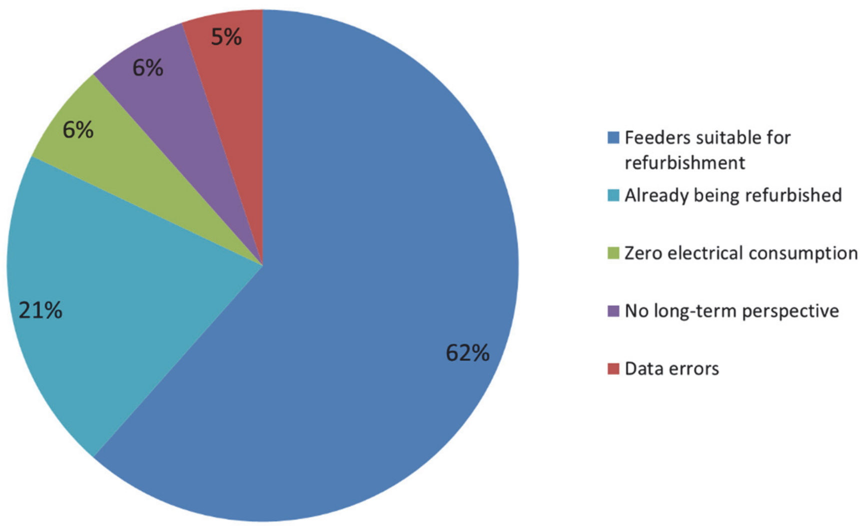

Figure 7 Distribution of feeders found by the methodology

To refurbish all of the 48 feeders, Elektrilevi OÜ would need to install approximately 30 km of low voltage line, 2.3 km of middle voltage line and 42 substations. By this refurbishment, they can also dismantle approximately 33 km of underutilized low-voltage network, which prevents ca 200 failures a year and resolves voltage quality problems for 102 connection points.

3.1.2. The benefits of the methodology

This methodology helps to find the optimal investment sites, which using algorithms that calculate the cost for solutions along the existing LV line corridor appear to be too expensive.

To illustrate this Figure 8 describe the same network area with and without knowing the middle voltage network configuration. In this chapter (3.1.2.) middle voltage lines are indicated in red and low voltage lines in green, blue line indicates the new middle voltage network and black lines indicate dismantled low voltage network. Because the existing low voltage line is too long for providing proper voltage quality, it is assumed that a new substation is required to refurbish the whole low voltage area.

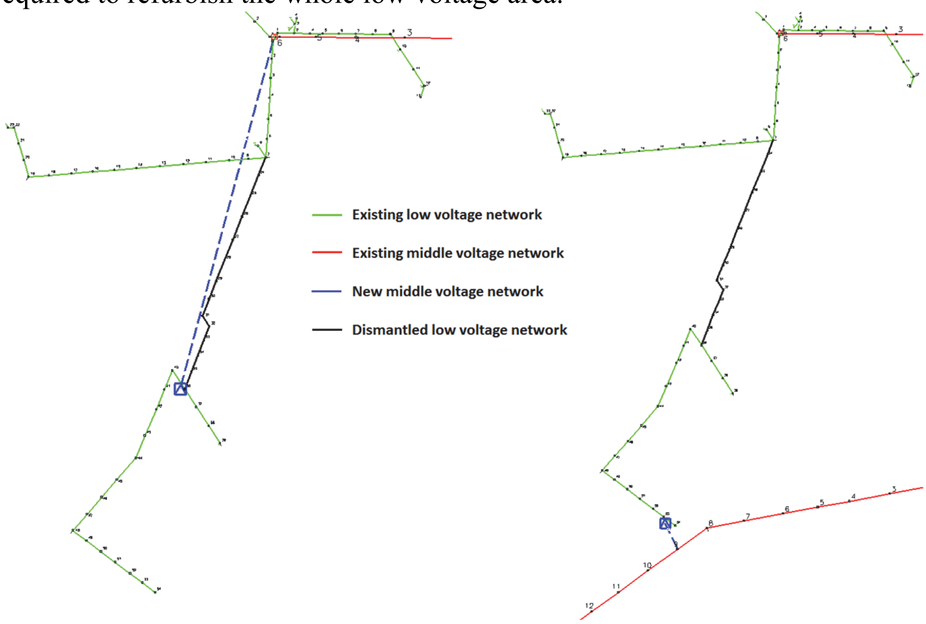

Figure 8 Example of a low voltage feed with and without knowing middle voltage network configuration

Standardized simple solutions are based only on the existing low voltage feeder (left picture on figure 8). However, our proposed method is able to detect the nearby MV line, which will clearly result in a more feasible solution. The cost difference between the standardized solutions and our new proposed solution is determined by the cost of length difference of old and new cable line. More accurate cost calculations will help the planner to find more favourable investment sites.

Figure 9 shows Mihkli substation feeder F3, one of the network sites found using the proposed methodology.

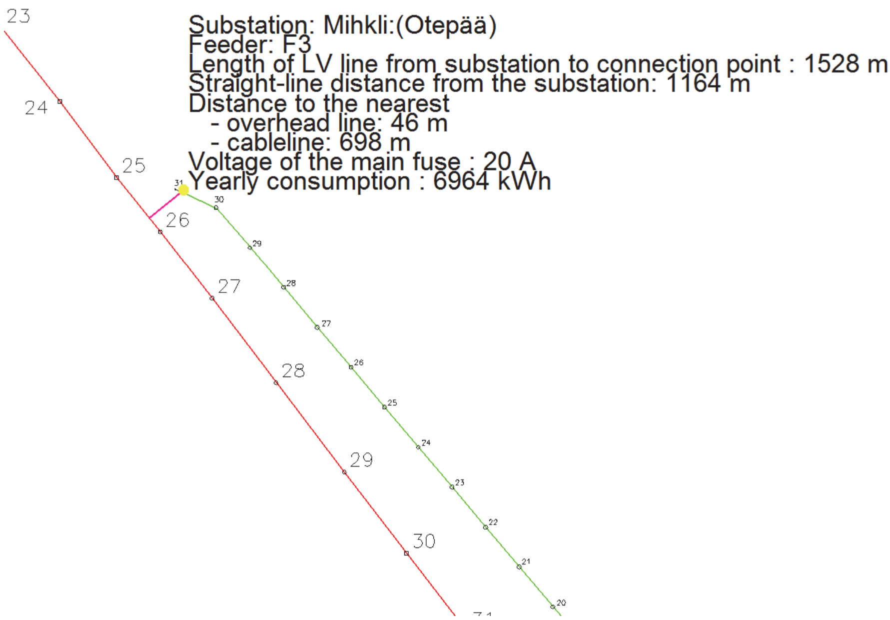

Figure 9 Example: Mihkli substation feeder 3

As seen on Figure 9, the closest middle voltage line (shown in red) is only a few dozen meters from the customer connection point, while the distance from the old substation along the existing low voltage line (shown in green) is more than 1,500 meters. Straight line distance from the nearest middle voltage line is marked in violet. As this client consumes electricity all year round, the refurbishment of the given project seems to be reasonable. However, the decision to go forward with any investment should always be done case by case and cannot be added to the methodology based on simple grounds.

3.2. Using 1 kV solutions in the rural areas

The testing of this approach was done mostly in MS Excel, the figures are made in Trimble NIS software.

3.2.1. Testing the approach

Using the approach provided in Chapter 2.3., all potential customers whose connection could be refurbished using 1 kV systems were located. Only customers who are located farther than 1 km from the substation were under evaluation. The total number of these customers was 7185. The energy consumption of 861 of those customers was zero during the past year and were therefore excluded from sample. From the remaining 6324 customers, only 461 can be refurbished using a 0.4 kV solution. 1877 customers are situated either too far from the substation or the nominal current of their feeder circuit breaker is too high even for 1 kV solution. The remaining 3986 (Table 1) is the total number of potential customers, whose power supply could be refurbished using 1 kV solution.

Table 1 Number of potential customers by cable type suitable for refurbishing

Type	No. of customers
AMKA 3x70+95 1 kV	1193
AMKA 3x120+95 1 kV	2793
TOTAL	3986

As there are often more than one customer on each feeder, the number of potential feeders should also be analyzed. Using the same criteria as for the customers, the resulting number of potential feeders suitable for refurbish using 1 kV system, is 2474 (Table 2).

Table 2 Number of potential feeders by cable type.

Type	No. of feeders
AMKA 3x70+95 1 kV	922
AMKA 3x120+95 1 kV	1552
TOTAL	2474

3.2.2. The potential benefit of using 1 kV solution

In order to show the possible benefits of using the 1 kV solution, the refurbishment of Holdre substation feeder 1 (Figure 10) was evaluated.

Figure 10 Holdre substation feeder 1

In all figures in this chapter (3.2), green represents existing 0.4 kV power lines, red existing 15 kV power lines or substations, blue represents new 1 kV lines and substations, purple represents new 15 kV lines and substations and black represents all dismounted lines and substations.

According to ELV network standards, new middle voltage underground power lines have to be built next to the roads. New middle voltage overhead power lines are not used as the total lifecycle costs are equal or greater than those of the underground cable lines. 1 kV overhead lines have the potential benefit of using existing poles, which cannot be used in middle voltage systems (they are too short).

The first alternative is to change the existing 0.4 kV power lines with an aerial bundled cable. However, because the distance from Holdre substation is 2335 m, this solution would not meet existing network standards.

The second alternative is to change the existing 0.4 kV power lines with an aerial bundled cable and use it on 1 kV, then add a new substation at the end of the feeder (Figure 11). Almost all existing poles have to be changed. In total, 2240 m of aerial bundled cable, one new substation and two transformers (15/1/0.4 kV and 1/0.4 kV) are needed. A total of 1460 m runs through a forested area. The initial investment cost for this solution is 52 263 €. In addition, the present value of the total lifetime expenses for this alternative is 22 645 €. Large expenses are mostly due to the deforestation costs. Therefore the total cost for the company is 74 908 €.

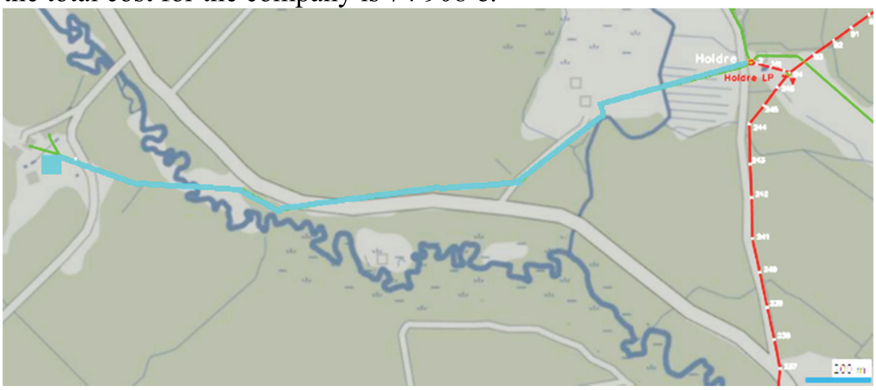

Figure 11 1 kV solution for Holdre substation feeder 1

The third alternative is to build a new middle voltage underground power line and a new substation area for the customers (Figure 12).

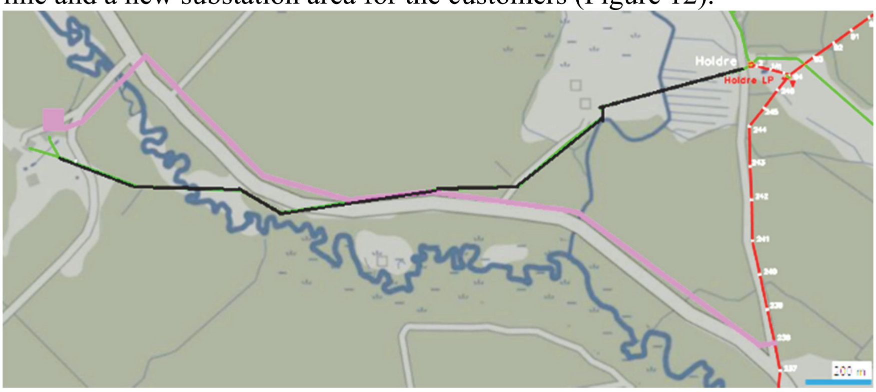

Figure 12 15 kV solution for Holdre substation feeder 1

The total length of a new middle voltage power line is 2624 m. In addition to the underground cable, middle voltage switching, one new substation and a transformer (15/0.4 kV) are needed. 0.4 kV power lines (except for the connection between customers) is dismounted. The initial investment cost for this alternative is 79 582 € and the present value of the lifetime costs for the company 4 576 €. Therefore the total cost for the company is 84 158 €.

The final results for either alternative are presented in Table 3.

Table 3 Initial investment and lifetime expenses of either alternative

Solution	Initial investment, €	Lifetime expenses, €	Total expenses, €
1 kV solution	52 263	22 645	74 908
15 kV solution	79 582	4 576	84 158
Difference	- 27 319	18 069	- 9 250

Therefore, using 1 kV solution would save ELV 9 250 € on the total lifetime expenses of this system. That is a significant 11 % of the total cost of the 15 kV solution that would be used at the time of writing this thesis.

There are also other possible benefits. One of the first 1 kV distribution systems that was built in Estonia in 2007, is situated in North-Estonia near Tallinn in Harku parish. 1 kV system was chosen because distances were too long for standard 0.4 kV system and required voltage quality could not be guaranteed. Also, a new middle voltage overhead line could not be built, as Estonian Law of Electrical Safety stated that mass gathering events (for example sports competitions) are prohibited in the protection area of high-voltage (>1 kV line-to-line) overhead lines.

3.3. Potential benefits of using off-grid as an alternative to the traditional network connection

Using the methodology presented in Chapter 2.4., the connection alternatives for customer A on Elektrilevi OÜ's Villa substation feeder 2 are evaluated. Solutions for the customer will be evaluated as if the other customer's connection does not need any refurbishment (e.g. the consumption of the other customers is nonexistent). As a simplification the customers' yearly consumption and the initial cost for the second off-grid cycle (on the 20th year) do not change in time. The initial cost is affected by the discount rate in the NPV calculations.

On all figures in this chapter (3.3.), color red represents existing middle-voltage power lines and green epresents existing low-voltage power lines. Blue is used to represent new low-voltage power lines, while purple is used for new middle-voltage power lines. The red square represents the existing substation, while the purple square represents a new substation or a new off-grid solution (if there is no connecting middle-voltage power line). Brown line represents dismantled low-voltage power line.

The first alternative, to provide a connection point for this customer is using an off-grid solution and dismantling the low-voltage line between customer A and customer B, with a total length of 0.47 km (Figure 13).

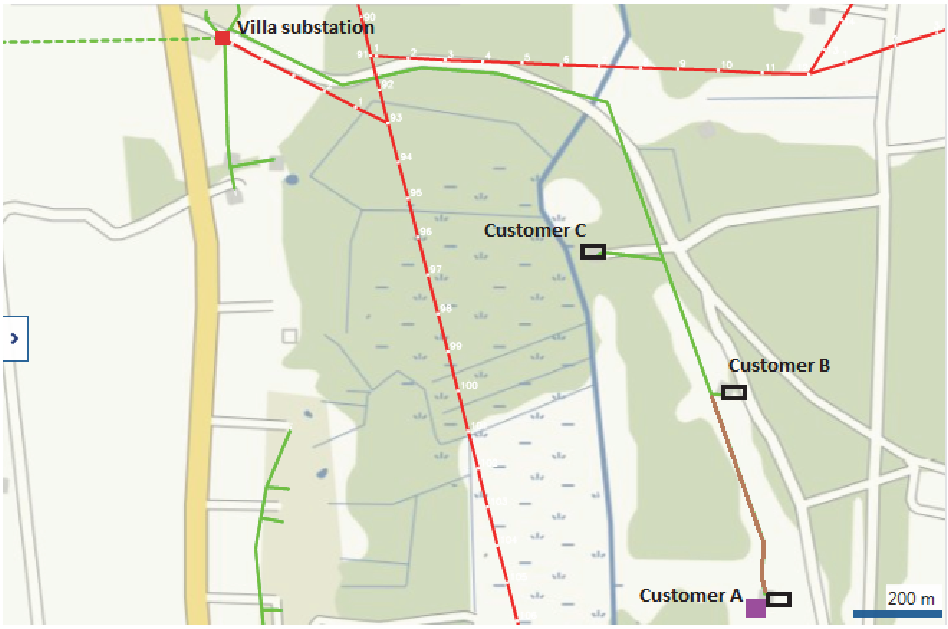

Figure 13 Off-grid alternative for customer A (Villa substation feeder 2)

Customer A is situated 2,065 km from the substation. The approximated figures used in the calculations are presented in Table 4. These figures have mostly been derived through the author's expert opinion. If a risk differs for either alternative, an additional index "*P*" (the power line alternative) or "*O*" (the off-grid alternative) is used.

Table 4 Approximated values used in the calculations

Figure	Value	Figure	Value	Figure	Value	Figure	Value
P	0.6	r	5.02%	E_{MOHL}	630	R_1	1.00%
V_t	300	C_{lv}	15000	E_{IOHL}	35	R_{2P}	3.30%
I_E	0..0296	C_{mv}	25000	E_{MS}	370	R_{2O}	0.00%
I_N	0..0364	C_S	10000	E_{IS}	40	R_3	0.00%
I_R	0..0537	C_{Sw}	5000	E_D	1200	R_{4P}	0.00%
V_{RG}	72.50%	C_{SB}	1152	E_F	1.25	R_{4O}	0.50%
THI	3.30%	C_B	1500	V_{AD}	0.303	R_5	0.00%
CCI	3.60%	C_G	308	V_G	27.50%	L_{lv}	0.47
i_d	7.40%	C_{Iu}	346	E_{Dr}	40.06	L_{mv}	0.93
i_e	2.70%	C_{In}	18058	V_f	150	n_s	1

The initial cost for the off-grid alternative is C_{01} = 20 042 €. Because in this paper the off-grid alternative has a useful lifetime of 20 years, a second investment on the 20th year is needed. The present value of this investment is 7 525 €, making the total investment cost 27 566 €.

The second alternative for customer A is to build a middle-voltage power line, a new substation to the area's load center and refurbishing the low-voltage line between customer A and customer B, with a total length of 0.47 km (Figure 14).

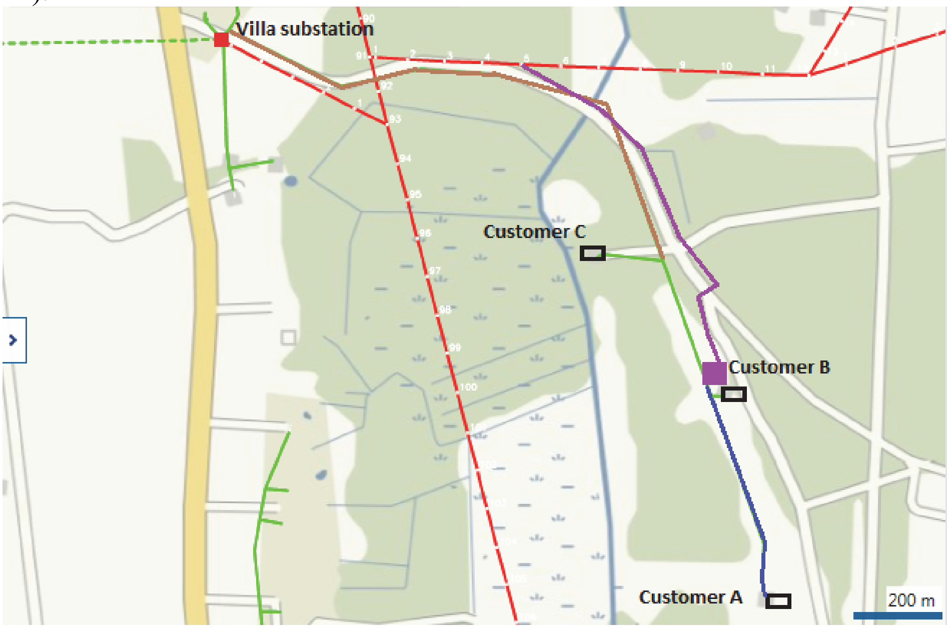

Figure 14 Power line alternative for customer A (Villa substation feeder 2)

The total length of the middle voltage power line depends on the distance of the existing power lines. Although there is an existing middle voltage power line situated relatively close to the load center, Elektrilevi's standards dictate that new cable lines (preferred method for building middle voltage power lines in this paper) have to be built along the roads, as it helps to decrease access problems and problems with the land owners. This is also necessary for future prospects, as the power line heading south will most likely also be refurbished as a cable line along the existing road during the useful lifetime of power line alternative. Therefore the total length of middle-voltage power lines for the second alternative is 0.93 km and the initial cost of the alternative C_{02} = 40 300 €.

There is no need for deforestation in the area that is refurbished. A total of 1.28 km of low-voltage power lines can be dismantled. As an additional benefit, the network reliability for customers B and C improves greatly. The distance between customer C and the new substation is almost three times shorter than the current one.

Even before NPV calculations, it is doubtful that the power line alternative can compete with the off-grid in this case, as the initial cost for the power line alternative is more than 30 % higher than the total investment cost of the off-grid alternative. The best way to evaluate the financial feasibility of both alternatives is to plot the discounted net cash flows on the same chart (Figure

15). As seen from the figure, neither alternative can provide a positive NPV. As one alternative has to be chosen, off-grid creates smaller losses and therefore should be chosen as the preferred alternative.

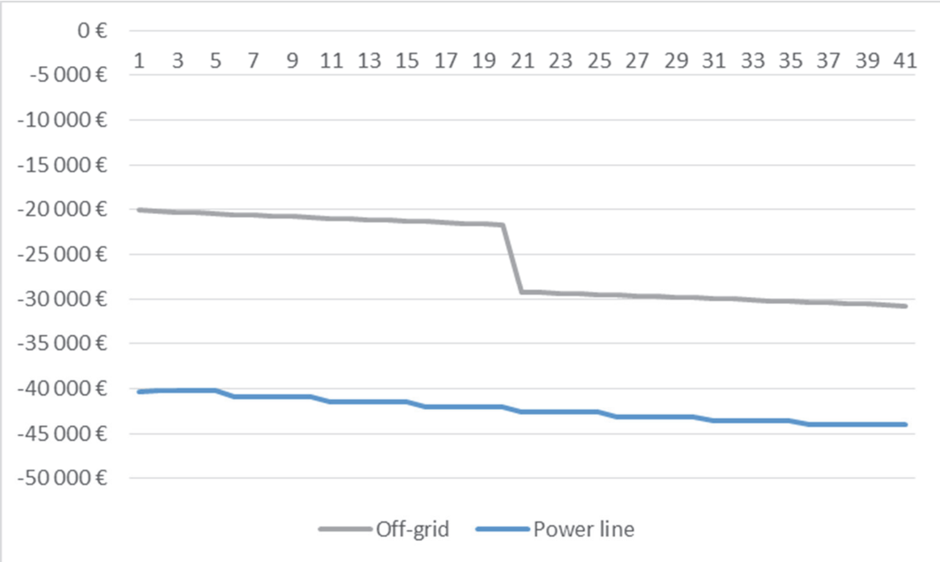

Figure 15 NPV for both alternatives for customer A (Villa substation feeder 2)

Therefore, there are customers whose network connection should be refurbished using off-grid solution. The methodology for finding the exact number of these customers has not been included into this thesis and is a topic that needs further study. There is however probably a high correlation with the number of suitable customers for the 1 kV solution.

4. DISCUSSION

4.1. Potential use of the optimization method for other networks

Although the method proposed in [III] had great results in Elektrilevi OÜ, it only works if there are still parts of the network where the configuration can easily be optimized. Therefore, this method has limited usefulness and mostly only for rural networks. However, this method can also be used in urban areas to provide additional feeding points and increase network reliability. The results of using this method in rural areas were impressive and it is easily applicable for other networks. Therefore, in the author's opinion, other distribution networks should consider using it to find better investment sites.

4.2. Other potential benefits and drawbacks of using 1 kV systems

1 kV low voltage system has been under evaluation in Finland and Sweden for some time and has proven its viability. The system is also in use in Norway and Latvia. Nevertheless, distribution networks form over a long period of time and no two systems are alike. Therefore, not all benefits and drawbacks that the 1 kV system presents exist in Elektrilevi OÜ network.

For example, in Finland over 90% of the network failures happen in the middle voltage network [11, 15], while in Elektrilevi OÜ about 75% of the network failures take place in low voltage network. Finnish practice shows, that replacing a faulty underutilised middle voltage overhead lines with 1 kV aerial bundled cable, it is possible to decrease the total length of middle voltage lines in that area by 10-30% while at the same time increasing network reliability. In Elektrilevi OÜ, the effect would be much smaller, as most failures take place in low voltage network.

An important risk factor is the absence of a long-term experience with 1 kV systems. The first 1 kV system in Finland was built in 2001. Therefore, these systems have not yet proven, that they are reliable on a long term basis. Because 1 kV systems usually use components designed for 0.4 kV systems, it is unclear how it could affect the isolation. Finnish experience [11] shows that partial discharges can appear in AMKA type aerial overhead cables when ambient humidity is high. In underground cables, electrical treeing has been observed.

Another risk in using 1 kV systems is the possibility of confusing these lines with 0.4 kV lines, as the material in use is the same. Therefore, it could increase the time of fault localization. For safety reasons, labelling becomes even more important. Finally, if the system is implemented on a small scale, the cost of some of the components (e.g. transformers) will be much larger and it would be difficult (costly) to keep an emergency reserve in case of faults.

The overall use of 1 kV solution in Elektrilevi OÜ network depends whether or not the potential financial and non-financial benefits justify the drawbacks listed above. The number of potential customers or feeders found were large, however the system should only be implemented in Elektrilevi OÜ on a large scale or not at all, as some of the drawbacks and risks listed above are only present if the system is implemented partially or in a small scale.

4.3. How off-grid systems affect distribution networks

The manufacturing cost of the solar panels decreased by more than twice between 2006 and 2011 [35], indicating technological advancements and an increase in the supply that could offset the demand. The cost of battery storage is also decreasing. UBS reports that the storage cost could fall under $100/ kWh compared to $720-2800/kWh that it costs right now [36]. This is probably due to Tesla building its new Gigafactory in Nevada USA, which will produce more than the total output of global cell supply in 2013 [37]. Taking into account this reduction in the prices, the off-grid becomes more feasible as a cost effective alternative to the traditional power line construction in the rural areas, where the density of population is small. The cost of battery banks is the key factor in the development of the off-grid systems. Currently most distributed generation relies on distribution networks for taking the excess power from the customer when not used and receiving power when the needs of the customer are greater than the output of the distributed generation.

The fast development in the renewable energy generation technology will create new opportunities that have a large impact on the distribution networks. The distribution networks can either passively react to this change and develop their network according to the customers' needs or take an active role and try to direct the development of the microgeneration by becoming one of the providers of this product. In the future, distribution networks may only provide power for urban areas, where the population density is large enough (i.e. the cost of battery banks is much larger than the cost of building the distribution network), while rural areas rely solely of off-grid systems. Whether or not the distribution network owns these systems is a strategic decision that the distribution networks need to make in the near future.

Also, as many of the potential customers for off-grid coincide with those of the 1 kV system, the distribution network should choose only of the two alternatives, else the small scale implementation of both systems generate the risks for both of them.

4.4. Different possible business models for using off-grid

There are a total of three business models evaluated in this paper: current service, rental service and sponsorship. Current service means, that from the customer's perspective, nothing changes. This model is the most convenient for the customer. It also gives the network company an early start and competitive advantage in the microgeneration market. Its main drawback is that under the price assumptions made in this paper, it provides a net loss on all periods and that the customer does not have a direct incentive to change his/her consumption habits in order to use the off-grid system optimally.

Rental service means, that the distribution network rents the off-grid unit to the customer along with basic maintenance, but the refueling cost will be covered by the customer. Off-grid has a negative net profit for all periods largely because of the refueling cost (using the pricing provided in this paper). Therefore, this business model provides a net profit for all periods. However, as long as the net cash flows have such a small impact on the overall net present value, this should not be the defining factor. For the customer this model holds higher risk, but there is a potential to save more money, as the customer directly controls his/her costs through refueling. To conclude, it has little advantages compared to the current business model and some of these advantages can be gained through other methods (e.g. customer consultation), while it may be harder to sell because it is less attractive to the customers.

Sponsorship means, that the distribution network supports the building of the off-grid unit (e.g. pays up to 30% of the initial investment costs), but the unit will eventually belong to the customer. The distribution network will thereafter be freed from the obligation of providing a network connection for a certain time period (e.g. lifetime of the off-grid unit). Because most cases where off-grid is currently viable have a negative net present value regardless of the alternative used, this helps to cut the investment costs considerably. Choosing this business model would greatly benefit the distribution network on a short-term basis. However, this means that the distribution network would technically be supporting their own competition. As microgeneration is becoming more and more popular, choosing this strategy could become a serious weakness in the long-term. From the customer's point of view, this business model has the highest risk and would most likely be the worst option.

To conclude, from the author's point of view, the best business model would be the current service model, as it has most of the advantages and only one disadvantage (negative periodic net cash flows). As the price of technology falls and the cost of labor increases, off-grid and microgeneration becomes more and more popular. Using off-grid to save money is a good opportunity to increase the know-how and through that gain an early competitive advantage. Therefore, in the author's point of view, sponsorship should not be viewed as a successful long-term strategy. Also, because current service business model can also use fixed price for a part of the service (e.g. network service), many of the advantages that the rental business model has can also be obtained through changing the pricing policy or other methods (e.g. customer consultations).

4.5. Off-grid or 1 kV system

The suitable customer base for either alternative is largely the same: lone customers situated far from the existing substation, where large investments would otherwise be needed. Small implementation of either system would provide additional risks (reserves for parts of the system in case of failures) and the relative cost per unit would be large. Therefore, large implementation would be preferable and before implementing either of the two alternatives, the distribution network needs to consider which alternative (if either) to use.

4.6. Other alternatives, not discussed in the paper

There are at least two more possibilities known to the author to minimize the investments into low voltage networks in rural areas that are not evaluated in this paper:

1. Using battery banks in the customer connection points to store energy during times of low consumptions and using it to support if there is need. This would help to keep the voltage level in the required interval. This method needs further study, before any conclusions can be made on its use.
2. Using voltage boosters. Voltage boosters are transformers in the middle of the feeder, that increase the voltage level in a small enough amount, so that both the customers at the start of long feeders and the end of the feeder receive voltage levels that meet the standard. This method has very limited usage, because increasing the voltage level for the last customer could ruin the voltage level for other customers.

CONCLUSION AND FUTURE WORK

To conclude, this thesis describes different possibilities for minimizing the total lifetime costs (investment and maintenance) for low voltage networks in the rural areas, where the number of customers is small and the relative length of the network large, i.e. where large investments are not justified. This topic is important, because reduction of costs and the increase of network reliability is always the focus point for all regulatory methodologies. There are three principal categories for optimizing network investments:

1. Optimization of the network configuration;
2. Use of other voltage levels;
3. Use of other alternatives to the traditional network connection.

The third article [III] proposes a methodology that helps network planners to find favourable investment sites. It calculates the distance between a connection point and the nearest middle voltage line element. If this distance is a lot smaller than the distance between the connection point and its substation (using the existing line corridor), then the optimal solution may be to build a new substation area and connect our customers to the new substation. This method was tested in Elektrilevi OÜ and 83% of the connection points found were considered effective (21% of which were already being refurbished). Therefore, the results were very good and this method can and should be used for network investment planning.

With small changes, this method should also be able to find nearby substations or LV line elements, therefore negating the need for a new substation and reducing the potential investment cost even further. Future research should evaluate how to implement such a methodology in an actual planning process. Also, there is a need for a methodology that evaluates the actual needs of a customer and its future outlooks.

If the network configuration cannot be optimized, large investments may be needed and the fourth article [IV] provides a methodology to evaluate the potential use of another voltage level: 1 kV solution as a cost effective alternative. The maximum length of a 0.4 kV feeder depends on the current of the fuse at the start of the feeder and the dimensions of the power line. Two restrictive factors were considered in finding the maximum length of 0.4 kV feeders: minimum one-phase short-circuit current and the maximum admissible voltage drop. A total of 3986 customers and 2474 feeders were found to be potentially suitable for 1 kV system in Elektrilevi OÜ. As the example provided in this thesis showed a significant saving on the total lifetime costs, the authors recommend using 1 kV solution in Elektrilevi OÜ.

There are three important topics that need future study. Firstly, before starting to implement a new voltage level, the distribution network needs to find the exact breaking point or the number of substation areas using the new voltage level needed, to overcome the drawbacks of 1 kV systems. Secondly, as 1 kV solutions and off-grid systems target the same customers, further study is needed to determine which system the distribution network should concentrate on. Thirdly, future peak load analysis is essential for any long term planning, therefore peak load analysis for the substations is needed. There are at least two studies [38, 39] that have already discussed this topic, but without considering the effect on the 1 kV system.

Lastly, an example of the third and final opportunity is presented in chapter 2.4., which provides a framework to calculate the use of off-grid as an alternative to the traditional power line construction. The use of this opportunity depends a lot on the customer's consumption habits, as larger consumption means larger investment and maintenance costs. Even at current prices, there are cases where off-grid solutions are cheaper than the traditional power line alternative. As off-grid solutions are technology intensive while the traditional power line construction is labor intensive, the off-grid alternative will become more and more financially feasible as time goes by. The distribution networks can either concentrate on their current core business and passively react to this change or take an active role and try to direct the development of the microgeneration by becoming one of the providers of this product. Using off-grid solutions also provides an opportunity for the distribution networks to potentially grow their market share.

Further studies are needed to create a methodology for finding all the customers whose connection points need refurbishment, and in which cases the refurbishment should be done using the off-grid alternative. Also additional uses of the off-grid alternative or its components (battery banks, microgeneration etc.) should be researched, in order to better evaluate the impact that the off-grid will have for the future distribution networks.

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ABSTRACT

This thesis describes different possibilities for minimizing the total lifetime costs (investment and maintenance) for low voltage networks in the rural areas, where the number of customers is small and the relative length of the network large, i.e. where large investments are not justified. This topic is important, because reduction of costs and the increase of network reliability is always the focus point for all regulatory methodologies. There are three principal categories for optimizing network investments:

1. Optimization of the network configuration;
2. Use of other voltage levels;
3. Use of other alternatives to the traditional network connection.

Firstly, a methodology for highlighting alternative investment solutions from a large number of investment projects is presented. The methodology identifies remote connection points located far from the sub-station where electricity can be provided from a nearby middle voltage line element. The methodology uses a mathematical model to find the smallest distance between a point (e.g. connection point) and a vector (e.g. middle voltage cable line). This methodology was tested in Elektrilevi OÜ where it proved to be very effective. This thesis also includes an example of using the provided methodology.

The second approach debates on the use of 1 kV system as a cost-effective investment solution in the rural areas and provides a methodology for finding potential investment sites. The methodology determines the maximum admissible 0.4 kV feeder length and through that the potential sites where 1 kV system could benefit the network company. An example of the potential benefits and drawbacks of using 1 kV systems are also included. This methodology was tested in Elektrilevi OÜ where it found a large number of potential customers and feeders.

Thirdly, this paper provides a framework to calculate the use of off-grid as an alternative to the traditional power line construction. Off-grid solutions usually consist of a renewable power plant, a storage battery, an inverter and a diesel generator. The use of this opportunity depends a lot on the customer's consumption habits, as larger consumption means larger investment and maintenance costs. As the prices for these components have a negative trend, the use of off-grid becomes more feasible as a cost effective alternative to the traditional power line construction in the rural areas, where the density of population is small. The methodology was used to calculate the refurbishment of the connection point for a customer in Elektrilevi OÜ distribution network. The results show that in some cases off-grid can be the better alternative, even if both alternatives provide a negative net present value. As the net cash flows have little impact on the overall results (using the values provided in this paper), a direct comparison of the total investment cost of either methodology can be used as a simplified evaluation method for the alternatives.

KOKKUVÕTE

Antud doktoritöö kirjeldab eri võimalusi madalpingevõrgu elukaare kulude minimeerimiseks maapiirkondades, kus klientide arv on väike ja võrgu pikkus kliendi kohta väga suur, mistõttu suurte investeeringute tegemine antud piirkonda on põhjendamatu. Teema on oluline, kuna olenemata regulatsiooni metoodikast, on kulude vähendamine ja varustuskindluse tõstmine alati jaotusvõrgu strateegia fookuses. Vaatluse all on kolm põhimõttelist võimalust, mida on arutatud kolmes eri artiklis:

1. olemasoleva võrgu konfiguratsiooni optimeerimine;
2. eri pingeklasside kasutamine;
3. alternatiivid traditsioonilisele võrguühendusele.

Esmalt pakutakse välja metoodika, mis aitab leida soodsaid investeeringu-objekte elektrivõrgus. Metoodika leiab tarbimiskohad, mis asuvad alajaamast väga kaugel, kuid mille lähedal kulgeb olemasolev keskpingeliin. Metoodika kasutab matemaatilist mudelit, et leida punkti (n. tarbimiskoht) ja vektori (n. keskpinge õhuliin) vaheline vähim võimalik kaugus. Metoodikat testiti Elektrilevi OÜ võrgus, kus see osutus väga efektiivseks. Toodud on ka näide metoodika kasutamisest.

Järgnevalt uuritakse 1 kV kasutamise võimalikkust kulu-efektiivse investeeringu lahendusena ja pakutakse välja metoodika potentsiaalsete investeeringuobjektide leidmiseks. Metoodika leiab maksimaalse võimaliku 0,4 kV fiidri pikkuse ja seeläbi võimalikud objektid, kus 1 kV lahendus võib ettevõttele kasu osutada. Toodud on ka näide koos potentsiaalsete tulude ja puudustega. Metoodikat testiti taas Elektrilevi OÜ võrgus, kus see osutus efektiivseks.

Kolmandaks pakutakse välja raamistik, mille abil hinnata *off-grid*i kasutamist kuluefektiivse alternatiivina traditsioonilisele elektrivõrgu ehitusele. *Off-grid*i lahendus koosneb üldjuhul taastuvenergiaallikast, akupangast, inverterist ja diiselgeneraatorist. Enamikul nendest hind ajas langeb, mistõttu muutub *off-grid*i kasutamine järjest levinumaks hajapiirkondades, kus rahvastikutihedus on madal. Antud metoodikat testiti Elektrilevi OÜ võrgu ühe kliendi elektriühenduse korrastamisel. Saadud tulemused näitasid, et ka täna on teatud juhtudel *off-grid*i kasutamine kasumlikum, isegi kui mõlemad alternatiivid toovad negatiivse nüüdispuhasväärtuse. Lihtsustatut hindamise metoodikana võib kasutada ka investeeringute kogumaksumuste otsest võrdlust, kuna rahavood seadmete elukaare jooksul omavad väikest mõju nüüdispuhasväärtuse lõpptulemusele (töös toodud väärtuste juures).

ELULOOKIRJELDUS

1. Isikuandmed

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2. Hariduskäik

Õppeasutus (nimetus lõpetamise ajal)	Lõpetamise aeg	Haridus (eriala/kraad)
Tallinna Tehnikaülikool	2015	Rahvusvaheline ärijuhtimine, Ärijuhtimise magistrikraad
Tallinna Tehnikaülikool	2012	Energiakaubandus, Tehnikateaduste magistrikraad
Tallinna Tehnikaülikool	2010	Elektroenergeetika, Tehnikateaduste bakalaureuse kraad

3. Keelteoskus (alg-, kesk- või kõrgtase)

Keel	Tase
Eesti keel	Emakeel
Inglise keel	Kõrgtase

4. Teenistuskäik

Töötamise aeg	Tööandja nimetus	Ametikoht
2016 –	Eesti Energia AS	Juhtiv Finantskontroller
2015 – 2015	Elektrilevi OÜ	Sektorijuhataja
2012 – 2015	Elektrilevi OÜ	Juhtivspetsialist
2011 – 2012	AS Elektritsentrum	Projektijuht
2010 – 2011	Kaitseväe Logistikakeskus	Vanemmeedik
2009 – 2010	Empower AS	Valdkonnajuhi abi
2003 – 2009	Empower AS	Abimontöör/ Töödejuhatataja abi

5. Kaitstud lõputööd

- Magistritöö: “Finantsanalüüs *off-grid*i kasutamiseks alternatiivina traditsioonilisele elektriliinide ehitusele”, 2015 juhendaja Tarmo Mere.
- Magistritöö: “Tuumajaama tasuvus Eestis avatud elektrituru olukorras”, 2012 juhendaja professor Juhan Valtin.

6. Teadustöö põhisuunad

Elektrivõrkude arendamine, kulude optimeerimine elektrivõrkudes, alternatiivid tavapärastele võrgulahendustele.

CURRICULUM VITAE

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2. Education

Educational institution	Graduation year	Education (field of study/degree)
Tallinn University of Technology	2015	Master of International Business Administration
Tallinn University of Technology	2012	Master of Science in Electrical Power Engineering
Tallinn University of Technology	2010	Bachelor of Science in Electrical Power Engineering

3. Language competence/skills (fluent; average, basic skills)

Language	Level
Estonian	Native language
English	Fluent

4. Professional Employment

Period	Organisation	Position
2016 –	Eesti Energia AS	Leading Financial Controller
2015 – 2015	Elektrilevi OÜ	Head of Division
2012 – 2015	Elektrilevi OÜ	Chief Specialist
2011 – 2012	AS Elektritsentrum	Project manager
2010 – 2011	Estonian Defence Forces - Logistics Department	Company Medic
2009 – 2010	Empower AS	Assistant to Head of Division
2003 – 2009	Empower AS	Assistant worker / foreman

5. Defended theses

- Master Thesis: “Financial evaluation of using off-grid as an alternative to the traditional power line construction”, 2005, supervisor Tarmo Mere
- Master Thesis: “Profitability of nuclear power plant in Estonia in open power market situation”, 2012, supervisor prof. Juhan Valtin

6. Main areas of scientific work/Current research topics

The development of distribution networks, cost optimization for distribution networks, alternatives to the traditional network connection.

APPENDIX A – Original publications

Paper I

Ots, M.; Hamburg, A.; Mere, T.; **Hõbejõgi, T.**; Kisel. E (2016). Impact of price regulation methodology on the managerial decisions of the electricity distribution network company. IEEE ENERGYCON 2016.

Impact of price regulation methodology on the managerial decisions of the electricity DSO

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Abstract **Electricity distribution network companies' activities and managerial decisions depend substantially on the applied regulatory methodology. The impact of different regulatory methodologies on different results like security of supply, investors' attractiveness and network tariffs level has been evaluated. The rate of return method has been used for the regulation of the electricity network tariffs in Estonia since 2004. The results of 10-year regulation period have been evaluated in comparisons to other methods available.**

Index Terms **Economics, power distribution, power system management, power system reliability**.

I. INTRODUCTION

Electricity distribution network companies' activities and managerial decisions depend substantially on the applied regulatory methodology. In this article, the impact of different regulatory methods on the strategic priorities of the companies with the aim of finding the best methodology for the main strategies that a distribution network company may have, are evaluated.

Some of the previous studies have assessed the impact of quality regulation on investment decisions [1] or have looked at the financial risks associated with performance based regulations [2] [3]. Up to now there seems to be a very limited number of studies exploring connections between a regulatory method and the managerial decisions of distribution network companies.

II. METHODOLOGY OF PRICE REGULATION

Price regulation methods [4] [5] can be divided into four categories: Price cap, Revenue cap; Rate of return and Long Run Average Incremental Cost Bottom Up (LRAIC BU). Pedell [6] has described all these three methods. Several sources as Green and Pardina [7], Netz [8], Armstrong and Sappington [9], Alexander et al. [10], Hertog [11], Joskow [12] [13] have described Price Cap and Rate of Return methods. The impact of regulatory practices have been described in a number of articles and regulators' reports [14] - [18].

If the pure rate of return method is used, then the risks associated with controllable and uncontrollable costs are covered, or in other words, the company has no risk associated with the costs. This method allows the company to apply for a tariff adjustment as soon as the price is not based on the costs of the company any more. Quite the contrary, pure *price cap* method leaves all these risks to be covered by the company and leaves options for the company to decide how to eliminate those in different ways. The only difference of the revenue cap is the elimination of sales volume risk.

The price cap method presumes that if the company can manage more efficiently on its own, it can earn extra profits, and also *vice versa*: if the company does not fulfil the expectations set by the regulator or manages less efficiently, its profit will be lower and it cannot earn profit agreed by the regulator.

The basis of the *price cap* method is fixing of prices for a certain time period. Doing so, the time period must be chosen long enough to guarantee that the company can reach the expected efficiency. On the other hand, the time period should not be too long in order to avoid high risk of forecasts. Each year the prices are adjusted in accordance with inflation and factor x, which reflects the cost efficiency target, or in other words, prices should not increase faster than inflation minus the efficiency goal x.

According to the (LRAIC BU) or hypothetical network model, an ideal network is modelled assuming that the most modern and optimal technological solutions for the network configuration to supply all customers with highest quality standards is used. In case of a distribution network, it should be modelled considering the geographical location of consumers and producers and with inputs from the transmission network. The distribution network is then configured as an ideal system and is assumed to be built in the most economical way to guarantee the supply of existing customers. It is assumed that the most economical solution is applied and the network is built as a Greenfield project.

All in all, the challenge in application of different regulatory methods for DSOs often comes back to the "management of strategic gaming" [19]. Each method triggers different economic actions from companies and regulators. Even in the most advanced British utility regulation one can observe constant urge to find better regimes for the companies concerned [20] [21].

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Since detailed sector-specific regulatory rules were introduced in Estonia in 2002 [22], the authors of the present article have more than 10 years of experience in the application of the described regulation methods. For 10 years the rate of return method has been used in Estonia for price regulation of distribution network companies [23] - [25]. In Figure 1 we can explore the actual return on capital[1] for four largest network companies in Estonia (Elering, Elektrilevi, Imatra Elektrivõrk and VKG Elektrivõrk[2]) and it has been compared with the WACC applied by the regulator [26]. As one can see from the results, the network companies have usually not reached the WACC level applied by the regulator. During its 10 years of existence the largest distribution Network Company Elektrilevi has never reached the WACC applied by the regulator, its actual result has always been below the expected level. The RoR implemented in Estonia differs from the classical type of RoR. The costs included to the tariffs are not based on historical cost base and the regulator is actively demanding implementation of cost saving measures: incl. reducing of energy losses, saving on operational costs, etc. The outcome clearly indicates that the RoR implemented in Estonia does not guarantee the required return.

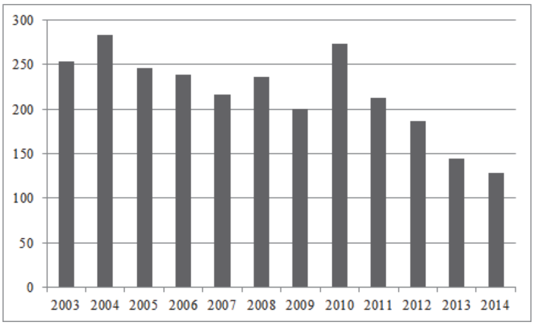

Figure 1. Return on capital of Estonian electricity network companies

III. METHOD FOR ASSESSMENT OF REGULATORY METHODOLOGY

Each regulatory method triggers a different logic of the managerial decisions taken by network companies. In the following sub-chapters one can find a comparison of the impacts assessed from the company's management perspective - how they would prioritise their activities and strategy having in mind different incentives provided by different methods.

Different methods for assessment of regulatory methodology were analysed. As it became clear to the authors that it would be impossible to provide reasonable impact assessment of regulatory methodology in monetary or technical terms without speculative assumptions, the assessment was carried out as an expert opinion of the authors on 5-point Linkert scale. The authors had to find a consensus in score in order to be approved. For each grade the rationale of the assessment discussed by the authors is also added.

Although this method is based on the authors' subjective judgements, it was considered to be the only appropriate way forward. The subjectivity is decreased by the fact that the authors represent opponent parties of the regulation. The assessments represent their long experience as practitioners in the energy sector in Estonia. As all the previously described regulatory methods have been applied in different sectors in Estonia, the assessments are based on the real practical experience.

The relevant managerial decisions of a network company can be divided into three wider groups as follows:

1) The Quality of Network Service presented in table 1
2) Cost of Network Service to Society presented in table 2
3) Risks of owners and lenders presented in table 3

On the basis of the method and criteria described above one can assess the impact of the different regulatory methods. In tables 4 to 7 the assessments of impact of regulatory methods on the managerial decisions of a power network company are described.

TABLE 1. CRITERIA FOR ASSESSMENT OF THE QUALITY OF NETWORK SERVICES SCORES

	1	2	3	4	5
Security of Supply level	Level decreases substantially	Level decreases	Current level remains	Level increases	Improvements faster than the level agreed on
Quality of Customer Service	Level decreases substantially	Level decreases	Current level remains	Level increases	Improvements faster than the level agreed on
Readiness to manage disruption crises	Very low, lack of needed financial and human resources	Below average	Average, needed financial and human resources are covered partly	Above average	High, sufficient financial and human resources are available
Long-term investments	Only critical investments are carried out to retain minimum standards	Below average	Sufficient investments in infrastructure, but not in technological development of the network	Above average	Investments are made as agreed, including also investments in innovative solutions
Stability of construction market	Investment volumes stable for 1-2 years	Below average	Investment volumes stable for 5 years	Above average	Investments volumes stable for 10 years

[1] Return on Capital is calculated on the basis of book records. Operating profit is divided by the sum of residual value of capital assets and working capital. The amount of working capital is used in calculations as 5% of the annual revenues.

[2] Elering is the TSO; Elektrilevi, VKG Elektrivõrk and Imatra Elektrivõrk are three largest DSOs in Estonia, with market shares of 87,3%; 3,0% and 2,7%.

TABLE 2. CRITERIA FOR ASSESSING NETWORK SERVICE TO SOCIETY

Score	1	2	3	4	5
Price Level	Highest price level	Slightly higher price	Average price level	Slightly lower price level	Lowest price level
Attractive-ness of the country for investors	Lowest level	Low level	Average level	High level	Highest level of attractive-ness
Admi-nistrative burden	The highest	High	Average	Low	The lowest

TABLE 3. CRITERIA FOR ASSESSING RISKS FOR LENDERS AND OWNERS

	Score				
	1	2	3	4	5
Risk of un-controllable costs and sales volume	Very high	Above average	Average	Below average	Very low
Objective regulatory lag	Very high risk	Above average risk	Average risk	Below average risk	Very low risk
Subjective regulatory lag	Very high risk	Above average risk	Average risk	Below average risk	Very low risk
Underinvestment risk	Very high	Above average	Average	Below average	Very low
Overinvestment risk	Very high	Above average	Average	Below average	Very low

TABLE 4. ASSESSMENT OF IMPACT OF PRICE CAP METHOD

Criteria	Score	Rationale for Score
Level of Security of Supply	2	Realisation of risks of increase of uncontrollable costs brings along a decrease of the operating costs; it may happen most promptly and influence first and foremost the maintenance and repair costs and investments in the network. Therefore the security of supply would be lower.
Quality of Customer service	3	As long as the company has a strong incentive to reduce its costs to raise its profit, the quality of customer service remains the same (if there is some inefficiency in the management) or decreases (by curtailing of existing services: e.g. reducing the number of people in call-centres extends the waiting time there).
Readiness to disruption crises	2	In order to increase efficiency the reserves of appliances are reduced; it makes the crises management more difficult.
Interest of the network company to carry out long-term investments	2	As long as there is some inefficiency in the management of a company, there is no impact on its long-term investments. However, when a company has reached a high level of effectiveness, the RPI-x can be only reached at the expense of long-term investments.
Stability of construction market	3	Realisation of risks of increase of uncontrollable costs brings along some reduction of investments (e.g. by restraining of works, prorogation to the future, etc.); that in turn restrains the construction market and makes the investment climate worse.
Price level to consumers	5	Price Cap should in principle give a lower price increase than RPI (however, if the investments exceed depreciation or the costs are evaluated inadequately, the regulator can also apply RPI+x in some cases,).
Attractiveness of the country to investors	3	As long as the company covers all the costs associated with connecting to the network, the cost for connection is high and attractiveness for investors low. Still, a presumed decrease of the network price can be attractive for some investors.
Administrative burden for the company	4	As the prices are adjusted for a fixed period (3-5 years), the administrative burden is rather low.
Risk of un-controllable costs and sales volume	1	All uncontrollable risks are borne by the company.
Objective regulatory lag	1	The price is fixed for a long period on the basis of the historical data: the Regulator sets the price for the following 5 years on the basis of the data from the previous full year.
Subjective regulatory lag	5	Fixed regularity, the risk is low.
Underinvestment risk	2	Strong pressure to reduce costs may lead to a decrease in the required investments.
Overinvestment risk	5	Constant requirement to reduce the costs limits the capability to invest.

TABLE 5. ASSESSMENT OF IMPACTS OF REVENUE CAP METHOD

Criteria	Score	Rationale for Score
Level of Security of Supply	3	Cost-effective network company can reduce its costs only at the expense of long-term investments, that hinders improvements in security of supply in long-term. Hedged risks help to keep the existing level of security of supply.
Quality of Customer service	4	As long as the company has a strong incentive to reduce its costs to raise its profit, the quality of customer service remains the same (if there is some inefficiency in the management) or decreases (by curtailing of existing services). Lower risk due to hedging of some associated risks.
Readiness to disruption crises	3	To increase efficiency the reserves must be reduced. Still, partly hedged risks provide possibilities to keep larger „hot reserve“ of appliances.
Interest of the network company	3	As long as there is some inefficiency in the management of a company, there is

to carry out long-term investments		no impact on its long-term investments. However, when the company has reached a high level of effectiveness, the RPI-x can be only reached at the expense of long-term investments.
Stability of construction market	4	Stable for 3-5 years, but during the regulatory period some changes in investment volumes may occur and that may impact the network construction and maintenance price and quality. A complicated situation from the partners' point of view (no long-term stability).
Price level to consumers	4	Revenue Cap should in principle give a lower price increase than RPI (however, if the investments exceed depreciation or the costs are evaluated inadequately, the regulator can also apply RPI+x in some cases).
Attractiveness of the country to investors	3	As long as the company covers all the costs associated with connecting to the network, the cost for connection is high and attractiveness for investors low. Still, a presumed decrease of the network price can be attractive for some investors.
Administrative burden for the company	4	As majority of the factors are fixed, the administrative burden is rather low. However, to compensate hedged risks the company has to keep the regulator constantly informed during the regulatory period and therefore the level of administrative burden is higher compared to Price Cap method.
Risk of un-controllable costs and sales volume	3	All uncontrollable risks are borne by the company, sales volume risk is hedged.
Objective regulatory lag	2	The price is fixed for a long period on the basis of the historical data: the regulator sets the price for the following 5 years on the basis of the data from the previous full year.
Subjective regulatory lag	5	Minimal, fixed regularity for adjustments.
Underinvestment risk	3	Strong pressure to lower costs may lead to a decrease in the required investments. Still, the risk is somewhat lower compared to Price cap method as far as some operating cost risks are hedged.
Overinvestment risk	5	Constant requirement to reduce the costs limits the capability to invest, the risk is low.

TABLE 6. ASSESSMENT OF IMPACTS OF RATE OF RETURN METHOD

Criteria	Score	Rationale for Score
Level of Security of Supply	4	Cost based price guarantees the changes of security of supply at the agreed pace.
Quality of Customer service	5	As long as company must reduce its costs, the quality of customer service remains the same (if there is some inefficiency in the management) or decreases (by curtailing of existing services). Lower risk due to hedging of associated risks.
Readiness to disruption crises	4	Reserves are kept as agreed with the regulator.
Interest of the network company to carry out long-term investments	4	Cost based price guarantees the development of the network at the agreed pace. The agreement on the allowed rate of return is the key to succeed.
Stability of construction market	5	Regular fixing of prices keeps the construction market stable.
Price level to consumers	3	In accordance with the agreed level of security of supply and customer service.
Attractiveness of the country to investors	3	As the company covers partly the costs associated with connecting to the network, the cost for connection is average and attractiveness for investors medium.
Administrative burden for the company	3	Regular adjustments (subject to the company's initiative for the price adjustment) make a medium administrative burden.
Risk of un-controllable costs and sales volume	4	Delays in adjustments are possible both by the regulator and the company.
Objective regulatory lag	4	As the price is not fixed for a long period (a potential 2-3 years' time lag still remains, as the price is set on the basis of the previous full year data), the risk is substantially lower compared to the other methods.
Subjective regulatory lag	2	Unlike the other methods there is no agreed time set – a company can apply for price adjustments any time. Possible delays by the regulator due to the bureaucracy or unwillingness to make unpopular decisions.
Underinvestment risk	4	As the regulation is strictly cost based, the risk of underinvestment is fairly low.
Overinvestment risk	3	Depends on the owner: if the owner is the state or a municipality, then the owner is also interested in the quality of the service; that is not always the case with private owners.

TABLE 7. ASSESSMENT OF IMPACTS OF LRAIC BU METHOD

Criteria	Score	Rationale for Score
Level of Security of Supply	1	If the modelled price is too low, then the company retrenches to survive. If the price is higher, then the company can maximise its short term profits by cutting the costs. This has a long-term negative impact to all selected indicators.
Quality of Customer service	1	
Readiness to disruption crises	1	
Interest of the network company to carry out long-term investments	1	
Stability of construction market	1	No stability as due to the cost-cutting only indispensable investments are made.
Price level to consumers	3	Stable as an ideal network does not change much, adjustments are only due to inflation.
Attractiveness of the country to investors	2	As long as the company covers all the costs associated with connecting to the network, the cost for connection is high and attractiveness for investors low.
Administrative burden for the company	1	Very complicated and demanding calculations. Ideal network requires permanent adjustments due to the changes in the network configuration.

Risk of un-controllable costs and sales volume	1	All uncontrollable costs and the sales volume risks are borne by the company.
Objective regulatory lag	1	Computing model calculates the theoretical costs required and the difference with the actual costs can be substantial.
Subjective regulatory lag	5	Fixed regularity, the risk is low.
Underinvestment risk	1	High risk of underinvestment as the company lacks a motivation to improve security of supply.
Overinvestment risk	5	Computing model defines the limits for investments, the risk is minimal.

IV. SELECTION OF THE PREFERRED REGULATORY METHOD

Selection of a regulatory method depends on the priorities of the government. Depending on the development stage of the electricity network, the priorities of the state may be either increasing the network quality, aiming for the lowest network tariffs to society, or providing low risks for the owners and lenders. Table 8 below describes overall results of the assessment carried out in Chapter 3; it can be as a basis for the selection of the regulatory method for policymakers.

TABLE 8. AVERAGE SCORES OF THE ASSESSMENT PER METHOD

	Price cap	Revenue cap	Rate of Return	LRAIC bottom up
Quality of Network Service	2.4	3.4	4.4	1
Cost of Network Service to Society	4.3	3.7	3	2
Risk of Owners and Lenders	2.8	3.6	3.4	2.6

The data in Table 8 provide grounds for a number of important conclusions:

- If the priority is to raise the quality of network, then the Rate of Return method appears to be the most suitable approach;
- In order to prioritise the low network tariffs to society, policymakers should select Price Cap method;
- In order to attract new owners and lenders to the network business, Rate of Return and Revenue Cap methods appear to be equally attractive approaches;
- To balance all these aspects, the Rate of Return method seems to be the most appropriate solution for a long term policy selection for the electrical networks regulation;
- LRAIC regulatory method seems not to be an attractive solution for the power distribution businesses.

However, it should also be noted that for the sake of a long term stable investment climate of the network business, it is advisable to avoid frequent changes of the regulatory methods. Frequent changes of regulatory methods may ruin the attractiveness of any investment in the energy sector [27]. Therefore the Rate of Return method has a clear advantage also in terms of the stable investment climate.

In order to double-check the outcome of the analysis we have also audited the impact of the Rate of Return method on Elektrilevi OÜ, the largest electricity network company in Estonia. The company is 100% owned by Eesti Energia AS, which in turn is 100% owned by the Estonian Government. The main objective of the government has been to maintain stability of the price of the network services while increasing the quality of the network. The increase of the value or attractiveness of the company has not been a priority for the government.

Figure 2 presents the changes of the electricity supply security indicator SAIDI[3] in Elektrilevi OÜ from 2007 to 2013. The calculations of SAIDI do not take into account the impact of occasional weather impacts.

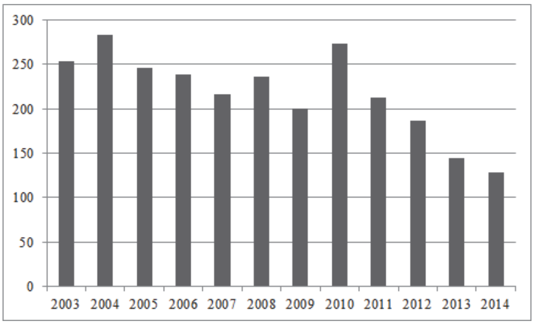

Figure 2. Changes in network quality indicator SAIDI in Elektrilevi OÜ

Graph 3 presents the network tariff and the rate on capital of Elektrilevi OÜ[4] in the timeframe of 2005-2014, adjusted to the changes of Consumer Price Index [28].

As it can be seen from Graph 2 and 3, the Rate of Return method has enabled improvements in the quality of the network services while the network tariff has remained stable for the customers and the company has earned reasonable returns on their investments. So the main objectives of the government as the owner of the utility and developer of the attractive utility services have been achieved.

[3] System Average Interruption Duration Index - the average outage duration for each customer served

[4] The network tariff of Elektrilevi OÜ is excluding the costs for transmission. The cost of transmission is excluded due to the fact, that this is a non-controllable cost for the company.

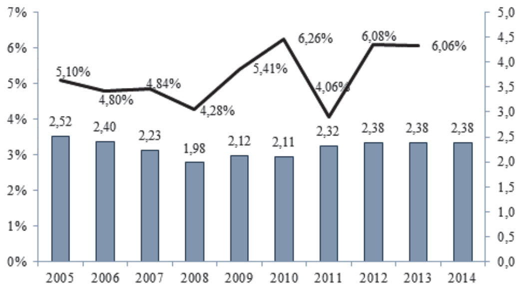

Figure 3. CPI adjusted price and return on capital of Elektrilevi OÜ services during from 2005 to 2014

V. CONCLUSIONS

The aim of the article was to analyse the impact of different regulatory methods of the electricity network companies on their strategic managerial decisions and to provide some advice for finding the most efficient method to reach the objectives of the network business. The analyses have been made by using the experience of regulation of distribution networks in Estonia. Four regulatory methods were analysed: price cap, revenue cap, rate of return and LRAIC BU. The managerial decisions analysed were divided into the network quality, cost of network service to society and the risk level for the owners and lenders.

As a result of the analysis and based on Estonian experience the Rate of Return method was assessed to be the best method for long term objectives. The impact of Rate of Return method was also controlled against the overall results of the activities of Elektrilevi OÜ, the largest distribution company of Estonia, where one can observe improvements in the quality of the network services while the price of the network service remained stable and its profit of the utilities was in an expected range.

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Paper II

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Network Quality Indicators and Overview of Long-term Load Forecasting Models

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Abstract— **Long-term load forecasting is one of the critical activities in electric power system planning. Load forecasting helps an electric utility to make important decisions including decisions on power purchasing and generating, load switching and infrastructure development, all of which help to improve network quality indicators. Load forecasts can be divided into three categories: short-term, medium and long-term forecasts.**

This paper presents basics of about network quality indicators and clustering algorithms and their usage for long-term load forecasting of a primary substation area in the city of Tallinn in Estonian. [4]

I. Introduction

As a customer, one wants the power supply to be continuous and reliable. The best way to characterize distribution networks reliability is through network quality indicators. All networks should work towards improving those or at least keep these at their current level. In order to do so, continuous planning and analysis of investment priorities have to be carried out.

The objective of power system planning is to determine a chronological order and economical expansion of the equipment to meet the customers' future electric demand on acceptable level of power quality. With a view to provide continuous, reliable and economic power supply the load forecasting has significant role in power system planning. A need for accurate load forecasts stems from the nature of electric power which cannot be stored. Nowadays, with electricity market liberalization a question of more accurate load forecasting becomes more and more important. The strategic guidelines of network development are set by long-term electric load planning in order to achieve higher utilization of each item of the power equipment and therefore better utilization of the entire power system. When planning the development of power grid we are particularly interested in forecast of peak loads of a grid. These determine the parameters of the planned network and need capacities of its elements (Cross-sections of lines, transfer capacities, rated currents of equipment etc.). There are a lot of different forecast methods which can be found in existing literature.

II. Network Quality Indicators

The number of network failures and SAIDI (System Average Interruption Duration Index) are the two primary network quality indicators used in Elektrilevi OÜ, the biggest distribution utility in Estonia.

In the year 2011 there were approximately 26 000 interruptions in Elektrilevi OÜ network. Of those 80% were failures on low and 20% on medium voltage level. Therefore, to lower the amount of failures, we should invest mostly into low voltage network.

Medium voltage failures result in large amount of customer outages and because of that they have a larger impact on SAIDI. Therefore we should concentrate on lowering the amount of medium voltage outages. As a result, if we want to improve both indicators, we have to invest into low as well as into medium voltage networks.

A. Network Quality Indicators

Network quality indicators show a systems ability to ensure the secure supply of electricity on specified conditions and a determined period of time. Primary network quality indicators are SAIFI, SAIDI and CAIDI. The basis of calculating those indexes is DMS (Distribution Management System), where all low and medium power outages with duration over three minutes are registered.

System Average Interruption Frequency Index SAIFI gives us the number of system interruptions per consumer in a certain power district on a certain time period:

$$SAIFI = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}}. \quad (1)$$

Lowering SAIFI usually means a rise in security of energy supply.

Customer Average Interruption Duration Index CAIDI shows us an average duration of a power outage:

$$CAIDI = \frac{\text{sum of all customer interruption durations}}{\text{total number of customer interruptions}} = \frac{SAIDI}{SAIFI}. \quad (2)$$

Lowering CAIDI does not certainly mean an increase in security of energy supply.

System Average Interruption Duration Index SAIDI shows the average duration of all power outages per consumer:

$$SAIDI = \frac{\text{sum of all customer interruption duration}}{\text{total number of customers served}}. \quad (3)$$

SAIDI is the best way to describe the functioning of an observed network or a part of it. SAIDI is an aggregated index and is usually described as minutes per customer. Reducing SAIDI means a definite increase in security of supply. [3]

Elektrilevi OÜ's goal in 2012 was to reduce the SAIDI due to scheduled outages (for maintenance and construction works) to 105 and failures to 248. [15]

B. Investment Budget and Investments in Network Quality

Elektrilevi OÜ investment budget in 2012 was 101 million EURs. The projected budget for 2013 is 109 million and in the coming years the budget will continue to grow. Although the amount is remarkable, a full third of this amount goes for new connections and metering equipment. In addition to that, 2013 marks the beginning of Smart-Metering project. This project itself will need about 20 million EURs per year.

To prevent large failures, primary substations and other important parts of the network need to satisfy the “n-1” criterion. Because of that, 25% of the investment budget goes to fulfill that preventative purpose and purposes from external sources.

Therefore only 40% of 2012 and 33% of 2013 investment budget is intended for improving network quality indicators. Externally it may seem, as though investments are increasing and therefore quality indicators should also improve at a faster base, but that is not the case.

TABLE I

IMPACT OF DIFFERENT REIABILITY RISING MANS ON QUALITY INDICATORS

Measure	SAIFI	SAIDI	AR
Light construction primary substations	>>	>	>>
Light construction 110 kV lines	>>	>	>
Underground cable networks	>>	=	>>
Insulated wires and air cables	>	=	>
Lines along the roads	>	>	>
Networks sectioning	>>	=	>>
Disconnectors remote control	=	>>	=
Improving management of distribution networks	>	>>	=

C. Improving SAIDI

Elektrilevi OÜ has purposed to reduce SAIDI due to scheduled outages to 50 and due to failures to 150. According to CEER report [15], that is the European average at the moment.

If we do not take into account the December storm in 2011, the SAIDI due to failures in that year was 254. In October 2012, the accumulated SAIDI was 122, which is 33 minutes less than the benchmark. Nevertheless we should not take this year as a reference point, because there have been no big storms and the weather has been favorable.

SAIDI due to scheduled outages for 2012 is expected to be approximately 90 minutes. As we cannot improve this index through work management, further improvement can only come from changing the network configuration: we need to eliminate all dead-end lines with more than 200 customers and add more circuit breakers. There is also a way to improve the index by expanding live working to medium voltage level. A more realistic estimate for SAIDI due to scheduled outages for year 2017 is 60 minutes.

While setting our goals, in decreasing SAIDI, we should not use European average value as a reference point. We should compare regions that have the same population density, load distribution etc. No one expects a farmer in Nordic countries to yield the same amount of crops as one in southern Europe, the same should hold for network quality indicators. Estonia has a lot of dispersed settlement, which means, that getting the same result for all customers will be rather expensive. Therefore we should divide customers into groups by consumption sectors or by areas and then assign them indexes according to cost of ensuring reliability considering the interruption costs for customers and utility.

TABLE II

2011 QUALITY INDICATORS FOR ELEKTRILEVI OÜ AND SUBSTATION 1

	MUSTAMÄE 35/6	Elektrilevi OÜ	Benchmart for 2017
Interruptions	3	33 145	
Over 3min interruptions	3	26 000	13 000
Number of customers	6 102	1 336 430	
Customer ‘ total interruption duration (min)	301 964	241 476 443	
SAIDI	0,47	254	150
SAIFI	0,01	2,10	

III. ELECTRICAL LOAD FORECASTING

Various load forecasting methods can be classified in several ways. Due to the time period of forecast, methods can be divided into short-term, mid-term and long-term forecast, as in [1,2]. Time periods mentioned are different from country to country and even from company to company.

Generally power networks development planning and design can be divided in three stages:

In Estonian distribution utilities common length for short term planning is up to 1 year. Short-term planning includes network components (lines, substations) designing which comprises a construction project, preparing the technical base for day-to-day operational control, creating market plan, and study of acceptance of technical implementation of network switching operations. Middle-term planning includes period from two to five years and comprises network design - a detailed analysis to determine the specific technical solutions and investments in the near future. The aim of the middle-term planning is defining objects for which basic activities, like defining concept solutions or defining routes, should to start immediately. Objects contained in the short and middle-term plans have to be coordinated with the distribution network long-term development plan. Long-term planning period in Estonia is used to be from 5 to 25 years. Network Development Planning fixes usually major investments and developments in the basic configuration of the network duration the planning period. It deals with identifying and researching potential weak points in the power system and determines the strategic direction of network development based on its configuration. Long-term planning of distribution network development is usually implemented with consideration of forecasted annual peak loads. A distribution planner must correctly forecast location and growths of loads in different parts of the distribution system. Spatial uncertainty of future loads significantly affects the next steps of planning. Analysis of the spatial characteristics should be implemented with sufficient geographical resolution for planning the location and features of the future electric distribution network. Therefore, the spatial forecast has been achieved by dividing areas of supply companies into many small areas and forecasting the load in each of them [2,9].

IV. Load Forecasting Methods

The trend analysis, end-use modeling, econometric modeling, and their combinations are the most often used methods for medium- and long-term load forecasting. Descriptions of appliances used by customers, the sizes of the houses, the age of equipment, technology changes, customer behavior, and population dynamics are usually included in the statistical and simulation models based on the so-called end-use approach. In addition, economic factors such as incomes per capita, employment levels, electricity prices, etc. are included in econometric models. These models are often used in combination with the end-use approach. Long-term forecasts based on forecasts of population changes, economic development, industrial construction, and technology development.

Trend Analysis: The trend extrapolation method uses the information of the past to forecast the load in future. A curve fitting approach may be employed to find the load of the target year. This approach is simple to understand and inexpensive to implement. The simplest model is:

$$W_n = W_0 \times (1+a)^n, \qquad (4)$$

where W_n – forecast of consumption for the n-th year
W_0 – consumption in initial year
a – consumption growth rate

End-use models. The end-use approach estimates energy consumption directly by using extensive information on end use and end users, such as kinds and ages of appliances in customers use, sizes of houses, and so on. Statistical information on consumption along with their dynamics is the basis for the forecast. End-use models focus on the various uses of electricity in the residential, commercial, industrial, and public sectors. These models are based on the principle that the total demand is derived from customers' demand for light, cooling, heating, refrigeration, etc. Thus the end-use models determine future energy demand as a function of the number of appliances in use and in the market. Ideally this approach is very accurate. However, it is sensitive to the amount and quality of the end-use data. In this method the distribution of equipment age is important for particular types of appliances. End-use forecast requires less historical data but more information about customers and their equipment.

Econometric models. The econometric approach combines economic theory and statistical techniques for forecasting electricity demand. The approach estimates the relationships between energy consumption (dependent variables) and macro-economic factors influencing consumption. The relationships are estimated by the least-squares method or time series methods. One of the options in this framework is to aggregate the econometric approach, when consumption in different sectors (residential, commercial, industrial, etc.) is calculated as a function of weather, economic and other variables, and then estimates are assembled using recent historical data. Integration of the econometric approach into the end-use approach introduces behavioral components into the end-use equations. [3]

A typical nonlinear estimation is:

$$D_i = a(PCI)_i^{\,b}\ (population)_i^{\,c}\ (el.price)_i^{\,d}, \qquad (5)$$

where PCI is income per capita and i denotes the year;

ˇ a, b, c and d are the parameters to be determined from the historical data.

Once this relationship is established, the future values of the driving variables (i.e. per capita income, population, electricity price, etc.) should be projected. Di for a future year can then be determined.

Combined Analysis. The end-use and econometric methods may be simultaneously used to forecast the load. It has the advantages and disadvantages of both approaches. [1,2,7,11]

In general these methods are suitable for forecasting loads of larger areas, such as the whole country or region.

Forecasts for smaller areas, as substations service areas, feeders, network regions in small quantity of consumption data require simplified methods, such as based on the growth rate [11], or on specific consumptions [10,11].

V. A Case Study for a Primary Substation Area

A. Actual Load and Consumption Data

Elektrilevi OÜ service area encompasses 246 primary (110-35 kV) substations, 231 switching stations and 21354 MV/LV distribution substations. All primary substations have actual load data recorded and stored. In this study we use the load data from a primary 35/6 kV substation in Tallinn. The data was obtained by SCADA (Vtrin ABB) which records hourly loads and composes consumption diagram for the substation transformer feeder. Load and consumption data has been monitored during the period from 2008 to 2012. The data is shown in the Table III. The transformer station is labeled as "Substation 1".

Primary substation service area in this example is about 2.3 km2 , 80% of it has been developed.

TABLE III
Load and Consumption Data From 2008 to 2012

Substation 1					
Year	2008	2009	2010	2011	2012
Pmax MW	8,9	9.2	9,3	8,76	9,2
W GWh	45,5	44,4	44,5	42,7	42*

* - derived, using the previous years' data's.

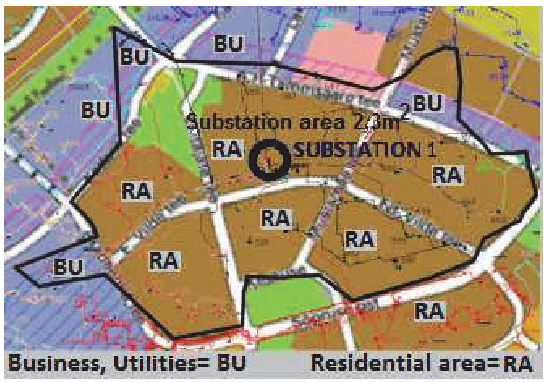

Fig. 1. Substation 1 service area.

There are mainly apartment buildings but also some shops, kindergartens, schools, offices, and industrial companies in the region in question.

Table IV describes consumption of customers in the area by consumer classes.

TABLE IV
CONSUMER CLASSES AND CONSUMPTIONS IN SUBSTATION 1 SERVICE AREA

Current data 2012 (04.11)	Number of customers	Consumption	Share of consuption
W_i		GWh	%
Residential	11646	32.97	62.46
Business	283	10.86	20.57
Mixed, Unknown	4118	8.96	16.97
Total	16047	52.79	100

We are mainly interested in peak loads. Following diagram in Figure 2 depicts the region's minimum and maximum load curves in diferen seasons. The Top line illustrates the week curve of winter period (February) and the bottom line summer period (June).

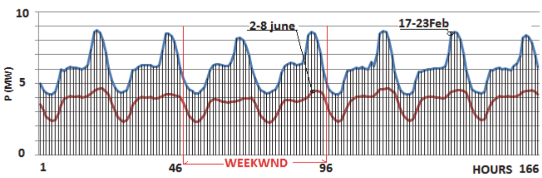

Fig. 2. Weekly load curve (winter and summer in 2012)

B. Consumption and Load Forecast

Consumption (demand) is defined as the quantity of electricity consumed in a given period of time. The rate of consumption is defined as load (i.e. the load capacity at some point). Consumption and loads are characterized by a number of indicators. Most important ones are listed as following.

$$T_{max} = \frac{W}{P_{max}}, \qquad (6)$$

where, T_{max} – peak load utilization time(h/a)
W – annual energy consumed(MWh/a)
P_{max} – substation peak load (MW)

Based on today's data, we use formula 6 to find peak load in the given area, assuming that this area has been developed completely.

In 2011, consumption density of this substation service area was 18.56 GWh/km2. Based on the fact that 20% of the region is underdeveloped, we found (using today's consumer division and energy densities) future consumption density to be 23.2 GWh/km2 and the annual consumption of 53.37 GWh. By formula 6 the new peak utilization (h/a) in 2011 is:

$$T_{max} = \frac{44400}{9,3} = 4774\text{h} \cdot$$

Using formula 6 the new peak load is:

$$P_{max} = \frac{53370}{4774} = 11,1\,\text{MW} \cdot$$

We can use also Velander's Formula 7: [3,5,6]

$$P_{max} = k_1 W + k_2 \sqrt{W}, \qquad (7)$$

where, k1, k2 – constants that depend on the characteristics of the consumer class.

In the given case Velander constants for residential areas are $k_1 = 0,29$ and $k_2 = 2,5$ and new peak load:

$$P_{max} = 0,29_1 53370 + 2,5_2 \sqrt{53370} = 16MW$$

This result is very general and does not take into account the fact that different consumer classes have different values of constants k1 and k2. [3]

The simplest method is forecasting by the consumption growth rate. To estimate the annual peak load one must find first annual consumption of the area in question. [11]

Formula 8 presents the long term load forecasting using the growth rate of the consumption.

$$W_n = W_0 \times (1+a)^n, \qquad (8)$$

where, W_n – forecast of consumption in year n
W_0 – consumption in initial (base) year
a – consumption growth rate

Using the constants a given in the following Table III, and consumption characteristics described above, one can predict the substation load until 2031. Using formula 5.4 one can predict the consumption by different consumer classes:

$$W_n = \sum_i W_{in} = \sum_i W_{i0} \times (1+a_i)^n, \qquad (9)$$

where W_{in} – the consumption forecast for consumer class i in year n;
W_{i0} – consumption of consumer class i in the base year;
a_i – consumption growth rate for consumer class i.

In Table V expert estimates of consumption growth rates for different consumer classes are given.

TABLE V
CONSUMPTION GROWTH RATE a_i FOR DIFFERENT CONSUMER CLASSES

Year	Residential	Business	Mixed, Unknown
2012	7.4	4.0	3.0
2013	6.4	3.9	2.9
2014	7.4	3.6	2.4
2015	6.5	3.7	2.7
2016	6.0	2.6	2.6

TABLE VI

ELECTRICITY CONSUMPTION GROWTH RATE a_i FOR DIFFERENT PERIODS

2017-21	2021-26	2027-31
2.1	1.4	1.2

Forecasting taking into account new customers in 2013 and local (detailed) planning capacities.

TABLE VII

DETAILED AND NEW CONNECTION CAPACITY

Detailed plans for the area				
New capacity (together) MW	Probability % 2012-2015	Probability % 2016-2020	Probability % 2021-2025	Probability % 2026-2030
3.813	0.05	0.05	0.9	1
New connections in 2013				
Capacity (MW)	Probability of joint capacity%			
0,2	0,25			

Load projections for the period 2012-2031 were received as following:

TABLE VIII

LOAD FORECAST UP TO 2031

2009	2010	2011	2012	2013	2014
8.9	9.2	9.3	9.9	10.5	11.1
2015	2016	2021	2026	2031	
11.8	12.3	13.9	18.3	23.3	

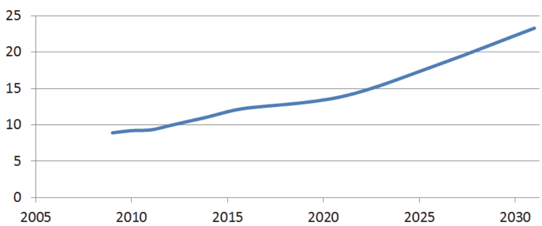

Fig. 3. Load forecasts (2012-2031)

VI. CONCLUSION

We provided an overview of network quality indicators and load forecasting methods, along with examples of calculations on a single substation area. All distribution networks should work towards improving those indicators, therefore continuous planning has to be carried out. Future load forcasting, a part of the planning, is very difficult: loads depend on many factors, for which the available information is incomplete and highly uncertain. Therefore, there are specific methodologys that allow loads to be accurately predicted, especially when making a long-term forecast.

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Paper III

Hõbejõgi, T.; Reinberg, A.; Last, K.; Laanetu, M.; Mere, T.; Valtin, J.; Hamburg, A. (2014). Methodology for finding investment sites that can be refurbished from a nearby middle voltage line element instead of using the existing low voltage line corridor. Przeglad Elektrotechniczny, 10, 199 - 202.

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Methodology for finding investment sites that can be refurbished from a nearby medium voltage line element instead of using the existing low voltage line corridor

***Abstract**. This paper proposes a methodology for highlighting alternative investment solutions from a large number of investment projects. The methodology identifies remote connection points located far from the sub-station where electricity can be provided from a nearby medium voltage line element. The methodology uses a mathematical model to find the smallest distance between a point and a vector. This methodology was tested in Elektrilevi OÜ where it proved to be very effective. This article also includes an example of using the provided methodology.*

Streszczenie.** W artykule przedstawiono metodę rozwiązań inwestycyjnych dla dużej liczby projektów inwestycyjnych. Metoda identyfikuje punty podłączenia oddalone od podstacji gdzie zasilanie może być dołączone do najbliższego elementu średniego napięcia. **Metodologia wyszukiwania lokalizacji inwestycji możliwej do zasilania z najbliższego źródła średniego napięcia zamiast linii niskiego napięcia

Keywords: network quality, investments, distribution network, finding refurbishment projects.
Słowa kluczowe: sieci zasilające, lokalizacja źródła zasilania.

doi:10.12915/pe.2014.10.48

Introduction

The lifespan of distribution networks infrastructure (power lines and substations) is very long and investments extremely resource intensive. Therefore, it is essential to invest as efficiently as possible. Distribution networks are created over a long period of time and the principles that govern these investments can change. Because of that, the original configuration of the distribution network will not always be the most optimal.

In this article we examine a method which helps network analysts find the most favorable investment sites, by finding non optimal medium voltage (MV) configurations that can be effectively used to decrease underutilized low voltage (LV) network. By taking into account the surrounding MV network, this method can find investment sites where renovation costs can be much lower than simple algorithms using only LV network would suggest. The objective of this method is to find parts of long LV feeds that can be refurbished by building a new substation area from a nearby medium voltage line element (MVLE). Ideally, we can then dismantle a large part of the LV line, thereby reducing underutilized network and increasing the overall network quality.

Because every distribution network has its own principles (which materials and solutions should be used in different situations), we only provide the methodology to find these sites and not the actual solutions.

This methodology was initially designed for the Trimble Network Information System (NIS) but can also be applied to other information systems. The Trimble NIS is a software application that can be used for asset management, network development and planning of repairs as well as documenting and managing network assets that are central to its system. Trimble NIS includes several modular industry applications:

- Power System Analysis,
- Network Planning and Construction,
- Asset Management,
- Maintenance,
- Network Investment Management [1].

This methodology was tested in Estonia's largest distribution network, Elektrilevi OÜ (ELV). ELV provides power to about 500,000 customers with a total consumption of approximately 6.5 TWh as recorded in 2013. The company manages around 63,700 km of power lines and 23,100 substations [2].

Network quality in this article, is measured by security of the supply (number of failures) and the voltage quality. For measuring voltage quality, we are going to use the Estonian standard EVS-EN 50160:2010. The standard nominal voltage for LV network is U_n = 230 V and under normal operating conditions excluding the periods with interruptions, supply voltage variations should not exceed ± 10% of the nominal voltage [3]. If the voltage does not meet the standard, then the customers in ELV network are entitled to receive a discount for the network service price.

Overview of previous studies

Previous studies have:

- Discussed problems of simulation models for modernization of regional LV and MV distribution networks and showed a computational algorithm for the needs for the network modernization [4].
- Discussed various methods of economical analysis of cross-country power networks and presented a modified variant of the annual cost method and the costs of cross-country network unreliability [5].
- Presented a method based on evolutionary strategies [6] and dynamic programming optimization [7] for designing distribution networks.
- Discussed the mixed-integer programming and the evolutionary programming methods of distribution network system planning [8].

The method discussed in this article is also designed for optimal solutions in the investments for the regional LV and MV distribution networks, but uses an approach previously overlooked.

Methodology

Firstly, we exclude all connection points that closer to their subsequent substation than the critical distance $Crit\_Dist$, using the length of the existing low voltage line. Secondly, we find those connection points, where the closest MVLE is closer than desired distance Max_Dist. MVLE can be any medium voltage cable or overhead line part, which begins (and ends) with a pole, switchboard or a turning point for a cable line.

Thirdly, we need to include add some background information for suitable connection points: x and y coordinates (latitude and longitude), connection point ID-code (used to distinguish different connection), size of the main fuse, yearly electrical energy consumption, name of the substation and the feeder.

Fourthly, we find the shortest distance between the connection points and the nearest MVLEs, using connection point coordinates and the start and end coordinates of the MVLEs. Finding the distances of all the MVLEs from all the connection points would be too resource consuming. To counter this problem, we compare the coordinates of connection point $P_3(x_3;y_3)$ and MVLE starting point $P_1(x_1;y_1)$. We only calculate the exact distance if the distance is less than the sum of our desired distance Max_Dist and the length of the MVLE. We use this sum because the closest part of the MVLE can just as well be the ending point.

The overall process is depicted in Fig. 1 (starting with yellow and ending with blue.

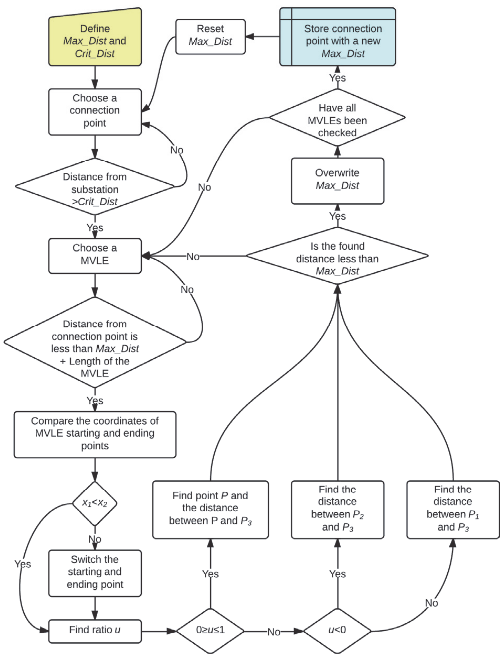

Fig.1. Schema depicting the overall process

We find this distance using the theory of distance between a point and a straight [3]. This straight passes through the starting point $P_1(x_1;y_1)$ and ending point $P_2(x_2;y_2)$ of our MVLE. Perpendicular for straight P_1P_2, that passes through $P_3(x_3;y_3)$ (the connection point), intersects with the straight passing through MVLE P_1P_2 in point $P(x;y)$ (Fig. 2 and 2). The positioning of point P can be calculated using formula 1.

(1) $$P = P_1 + u \cdot (P_2 - P_1)$$

where: u – ratio, that represents the relative distance between P and P_1.

If point P is situated on straight P_1P_2, then the distance between P_1P_2 and P_3 equals the distance between P and P_3 and $0 \leq u \leq 1$ [9]. The dot product of two orthogonal vectors equals to zero, therefore:

(2) $$(P_3 - P) \cdot (P_2 - P_1) = 0$$

We replace P using formula 1:

(3) $$\left[P_3 - P_1 - u \cdot (P_2 - P_1)\right] \cdot (P_2 - P_1) = 0$$

Using formula 3, we can find ration u (4):

(4) $$u = \frac{(x_3 - x_2) \cdot (x_2 - x_1) + (y_3 - y_2) \cdot (y_2 - y_1)}{(x_2 - x_1)^2 + (y_2 - y_1)^2}$$

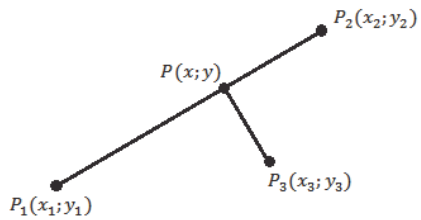

Fig.2. Distance between P_3 and P_1P_2 if $0 \leq u \leq 1$

We can find the coordinates $(x;y)$ for point P by replacing u in formula 1 (5).

(5) $$x = x_1 + u \cdot (x_2 - x_1)$$
$$y = y_1 + u \cdot (y_2 - y_1)$$

Because MVLE are parts with a definite length, then we also need to consider situations where point P is situated outside MVLE and $u<0$ or $u>1$.

Fig. 3 depicts a line with a MVLE part P_1P_2. The distance between the straight passing through MVLE part P_1P_2 and our connection point P_3 is not the same as the distance between MVLE P_1P_2 and connection point P_3. In this case the distance we are looking for is either the distance between P_1 and P_3 or P_2 ja P_3.

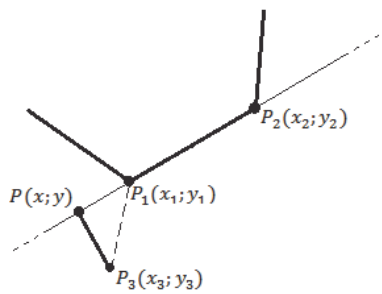

Fig.3. Distance between P_3 and P_1P_2 if $u<0$

The distance between P_1 and P_3 can be found with formula 6 [10].

(6) $$P_1P_3 = \sqrt{(x_3 - x_1)^2 + (y_3 - y_1)^2}$$

where: $P_1(x_1;y_1)$ – MVLE starting point, $P_3(x_3;y_3)$ – connection point.

In order to find out our current situation, we evaluate the corresponding u ratio. If $0 \geq u \leq 1$, then point P is situated on MVLE part P_1P_2 and the distance we are looking for is PP_3. If $u<0$, then we have to find the distance between P_1 (MVLE starting point) and P_3 (connection point). If $u>1$, then we have to find the distance between P_2 (MVLE ending point) and P_3 (connection point).

This method only works if the x-coordinate of the starting point P_1 of MVLE is smaller than the x-coordinate of the ending point of MVLE ($x_1<x_2$). If this is not the case, we

need to switch the coordinates of our starting and ending points before using the method. Also for the same reasons if $x_1=x_2$ and $y_1<y_2$, then we have to switch the y-coordinates of our starting and ending points before using the method.

Testing the methodology

The methodology was tested in the ELV network. The query that supports the methodology was written in SQL query language and the query was run in Oracle SQL Developer software. Oracle SQL Developer is a free integrated development environment that simplifies the development and management of Oracle Database [11].

In order to reduce the sample size, we used the following restrictions:

- *Crit_Dist* = 1500 m,
- *Max_Dist* = 100 m.

Using these restrictions, a total of 92 connection points was found on a total of 78 feeders. The location of these connection points is shown in Fig. 4 (connection points which are located close to each other are displayed as a single dot). This sample size was considered optimal for an initial testing on the basis of expert judgment, taking into account the budget size reserved to test the methodology. In order to increase the sample size, we should start with increasing the *Max_Dist* component as the increase in the solution cost would be rather insignificant.

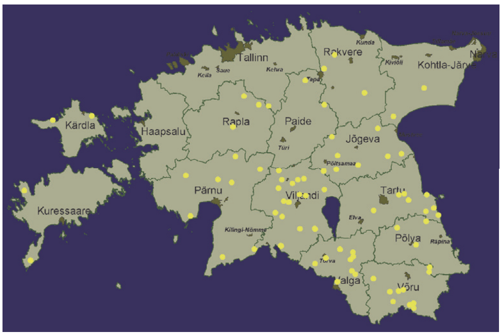

Fig.4. Connection points found by applying the proposed Methodology

Fig. 4 shows that the majority of the connection points found are located in the south-eastern region. Generally, this is in rural region where consumption is rather fading and, therefore, large-scale investment does not have perspective. Therefore, it is necessary to invest optimally, which this methodology strongly supports.

All found feeders were further examined to ensure that:

- Investment is sensible,
- There is no error in the data,
- They not currently being refurbished.

Investment is considered not sensible, if there is currently no valid network contract or the last year's electrical consumption was 0 kWh. It is not clear whether the consumption in these connection points will recover or if the connection point vanishes completely (e.g. with the old homestead). Five feeders were left out because of zero consumption. Also, after completing finalized investment solutions, five feeders were considered without long-term perspective because of changing MV network.

After further examination, 47 solutions were sketched to refurbish a total of 48 feeders. Two feeders are being refurbished with a common solution because they were located side by side. The diagram of found feeder's distribution is shown in Fig. 5.

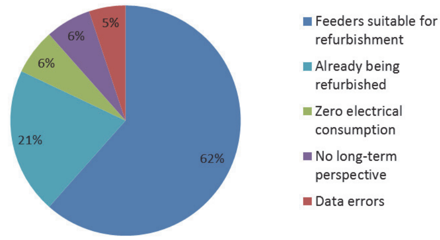

Fig.5. Distribution of feeders found by the methodology

To refurbish all of the 48 feeders, ELV would need to install approximately 30 km of LV line, 2.3 km of MV line and 42 substations. By this refurbishment, they can also dismantle approximately 33 km of underutilized low-voltage network, which prevents ca 200 failures a year and resolves voltage quality problems for 102 connection points.

The benefits of the methodology

This methodology helps to find the optimal investment sites, which using algorithms that calculate the cost for solutions along the existing LV line corridor appear to be too expensive.

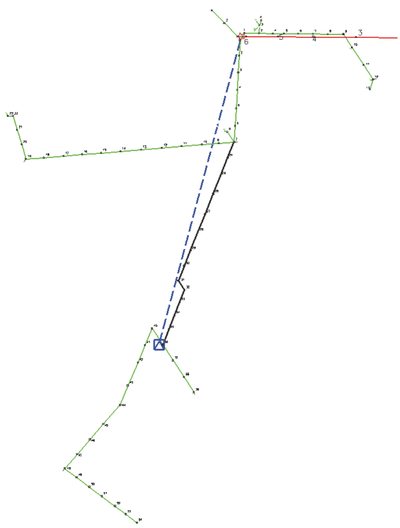

Fig.6. Solution along the existing LV line corridor

To illustrate this Fig. 6 and 7 describe the same network area. On these figures MV lines are indicated in red and LV lines in green, blue line indicates the new MV network and black lines indicate dismantled LV network. Because the existing LV line is too long for providing proper voltage quality, let us assume that a new substation is required to refurbish the whole LV area.

Standardized simple solutions are based only on the existing LV feeder (Fig. 6). However, our proposed method is able to detect the nearby MV line, which will clearly result in a more feasible solution. The cost difference between the standardized solutions and our new proposed solution is determined by the cost of length difference of old and new cable line (Fig. 7). More accurate cost calculations will help the planner to find more favourable investment sites.

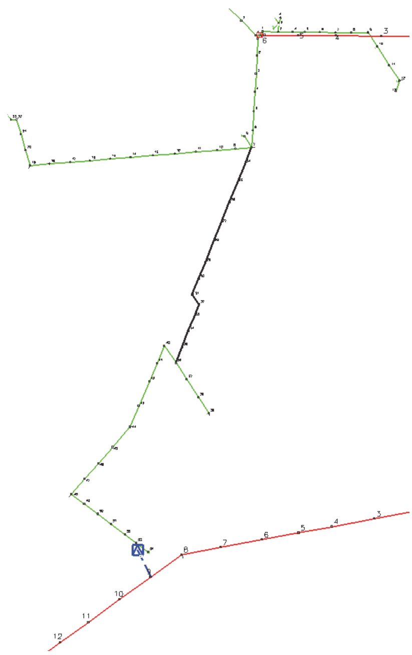

Fig.7. Solution using a nearby MV line

Fig. 8 shows Mihkli substation feeder F3, one of the network sites found using the proposed methodology.

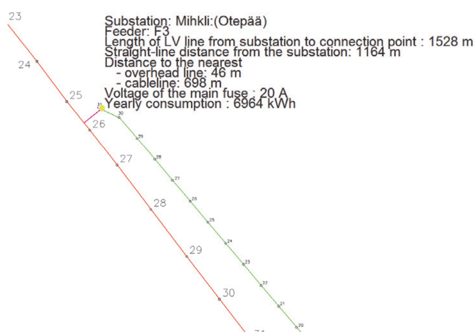

Fig.8. Example: Mihkli substation feeder 3

As seen on Fig. 8, the closest MV line (shown in red) is only a few dozen meters from the customer connection point, while the distance from the old substation along the existing LV line (shown in green) is more than 1,500 meters. Straight line distance from the nearest MV line is marked violet. As this client consumes electricity all year round, the refurbishment of the given project seems to be reasonable. The decision to go forward with any investment should always be done case by case and cannot be added to the methodology based on simple grounds.

Summary and outlooks

To conclude, this paper describes a methodology that helps network planners to find favourable investment sites. This method calculates the distance between a connection point and the nearest MVLE. If this distance is a lot smaller than the distance between the connection point and its substation (using the existing line corridor), then the optimal solution may be to build a new substation area and connect our customers to the new substation.

This method was tested in ELV network and 83% of the connection points found were considered effective (21% of which were already being refurbished). Therefore, the results were very good and this method can and should be used for network investment planning. However, the decision to go forward with the investment should always be done case by case. The restrictions used to test the methodology were chosen to provide a suitable number of feeders for testing and do not pose any actual limitations. The restrictions can be changed in order to provide more potential investment sites.

With small changes, this method should also be able to find nearby substations or LV line elements, therefore negating the need for a new substation and reducing the potential investment cost even further. Future research should evaluate how to implement such a methodology in an actual planning process. Also, there is a need for a methodology that evaluates the actual needs of a customer and its future outlooks.

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Paper IV

Hõbejõgi, T.; Vill, K.; Valtin, J. (2015). Evaluation of using 1 kV distribution system as a cost effective alternative to the middle voltage systems. Przeglad Elektrotechniczny, NR 2/2016.

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1 kV distribution system as a cost effective alternative to the medium voltage systems

Abstract*. This article debates on the use of 1 kV system as a cost-effective investment solution in the rural areas and provides an approach for finding potential investment sites. This approach determines the maximum admissible 0.4 kV feeder length and through that, the potential sites where 1 kV system could benefit the network company. An example of the potential benefits and drawbacks of using 1 kV systems are also included. This approach was tested in Elektrilevi OÜ and the number of potential feeders was substantial. Therefore, Elektrilevi OÜ should consider using 1 kV systems.*

Streszczenie. *In this place the editor of journal inserts Polish version of the abstract.*
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Polish version of the abstract

Keywords: 1 kV system, distribution network, investments, finding refurbishment projects.
Słowa kluczowe:

Introduction

The lifespan of distribution networks' infrastructure is very long and investments extremely resource intensive. Therefore, it is essential to invest as efficiently as possible. However, distribution networks are created over a long period of time and the principles that govern these investments can change. Because of that, the original configuration of the distribution network will not always be the most optimal and may become inefficient in providing electricity for nowadays needs. If configuration cannot be optimized [1], large investments are needed. This article debates on the use of 1 kV system as a cost-effective investment solution in the rural areas and provides an approach for finding potential investment sites.

The authors created this approach for Elektrilevi OÜ (ELV), Estonia's largest distribution network, but it could also be used in other networks. ELV distributes power to about 500,000 customers with a total consumption of approximately 6.5 TWh as recorded in 2014. The company manages around 64,000 km of power lines and more than 24,000 substations. Although ELV has 15 1 kV substation areas that were built mostly in 2008, the use of the solution was discontinued in 2009 (Fig. 1).

We evaluate using 1 kV power lines to refurbish the low-voltage feeders of those customers, who currently have a 0.4 kV solution, but are situated too far from the substation, to provide power according to nowadays' standards. Currently, the standard solution in use in ELV is building a new medium voltage power line along with a MV/LV substation for these customers.

Firstly, we give an overview of some of the papers written on the subject of 1 kV distribution network. Secondly, we provide an approach for finding the number of potential customers, who could be refurbished using the 1 kV solution and how to evaluate the possible financial benefits it provides. Thirdly, we debate on the negative effects that using 1 kV solution has and why it was discontinued some years ago and provide a positive example of how it could provide a financial benefit. Finally, we test the approach presented in this paper in the ELV distribution network and give our expert opinion based on the results whether or not ELV should reconsider using the 1 kV solution according to the number of potential customers and its drawbacks.

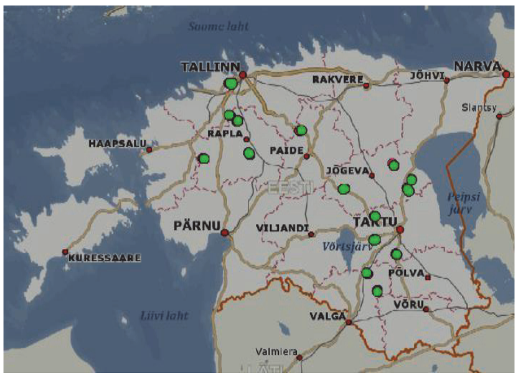

Fig. 1. Current 1 kV substation areas in ELV

Former studies on 1 kV systems

1 kV low-voltage systems became popular at the start of this century. The first 1 kV system known to the authors was built in 2001 by Suur-Savon Sähko OY, a Finnish distribution network [2]. Because of that, most of the research on the technical and economic evaluation of 1 kV systems in distribution networks were done in 2003-2007 by Lappeenranta University of Technology started. There are

several master's thesis and at least one PhD thesis on this topic [2, 3, 4].

Most of the research done on 1 kV systems studies the benefits of refurbishing short low-loaded 20 kV overhead power lines that are underutilized, with 1 kV systems. Some studies also evaluate the financial feasibility of the 1 kV systems compared to other alternatives for increasing network reliability [5, 6, 7, 8].

Few articles on the topic have been published after 2009. However, some interest has resurfaced in the Swedish network company Vattenfall Eldistribution AB. An article by D. Söderberg and H. Engdahl studies the possibility of using 1 kV systems for providing power for electric vehicle charging stations and households in the rural areas. This topic is important because the growing use of electrical cars and the ever higher quality standards for household applications increases the pressure on the distribution networks [9]. In his 2013 article [10], D. Söderberg analyses the necessary parameters for transformers operating in the 1 kV system.

Description of calculation method

Because 1 kV solutions are not standard in ELV, building a completely new power line will most likely be just as if not more expensive than building a medium voltage power line. Therefore, only those feeders, where the existing poles can be used will be under evaluation. In order to calculate the maximum length of these feeders, AMKA-type aerial bundled cable will be used. The standard dimensions and resistances for AMKA are presented in [11]. Increasing the cross-section of the cable, the weight increases also, meaning that the existing poles may also need replacement, increasing the investment costs.

One of the restricting factors of the length of the feeder is the tripping time of a fuse situated on the start of the feeder. In ELV distribution networks, usually gG-type fuses are used for feeder overcurrent and short-circuit protection in MV/LV substations. According to the standard IEC 60364-4-41, the maximum allowable tripping time during one-phase fault is 5 seconds. Minimum one-phase short-circuit current (in temperature 40^0 C and a coefficient for voltage 0.95 as stated in the standard IEC 60909-0) can be calculated according to eqn. 1:

(1) $$I_k^{(1)} = \frac{0{,}95U_n}{\sqrt{3}\left(2{,}16z_f + z_{tk}^{(1)}\right)}$$

where: U_n – nominal line-to-line voltage of the network (V), z_f – feeder total impedance on the temperature 20^0 (Ω), $z_{tk}^{(1)}$ – transformer impedance during one-phase fault (Ω).

As the standard IEC 60269 states minimum short-circuit current for gG-type fuses and cable impedances per kilometer are known, the maximum length l of the feeder in km-s can be calculated according to eqn. 2:

(2) $$l = \frac{1}{2{,}16z_j}\left(\frac{U_n}{\sqrt{3}I_{kmax}^{(1)}} - z_{tk}^{(1)}\right)$$

where: z_j – cable impedance per kilometer, Ω/km

Transformer impedances during one-phase fault for Yzn vector group transformers mostly used in ELV network are presented in [12]. Another important restriction is the maximum allowable voltage drop along the feeder at nominal load. In ELV, the maximum admissible voltage drop used for designing and construction of new power lines is 5%.

In practical calculations, eqn. 3 is used for estimating the maximum voltage drop $\Delta u_{\%}$ of a feeder:

(3) $$\Delta u_{\%} = \frac{\sqrt{3}I_l z_j l}{10U_n}$$

where: I_l – load current of the feeder (A), z_j– cable impedance per kilometer (Ω/km), l – feeder length (km), U_n – nominal line-to-line voltage of the system (kV).

As the maximum admissible voltage drop 5% is known, the length of the feeder can be calculated using eqn. 4:

(4) $$l = \frac{50U_n}{\sqrt{3}I_l z_j}$$

Maximum admissible feeder length is determined by stricter criterion of both as described above. Using this method, it is possible to calculate the maximum length of the feeder (Fig. 2).

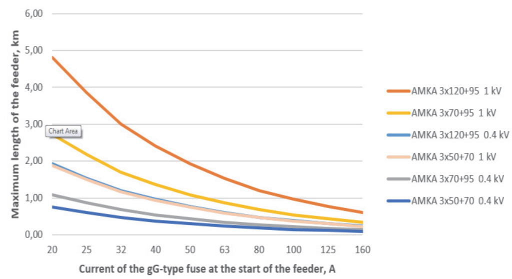

Fig. 2. Maximum length of the feeder depending on nominal current of the fuse and dimensions of the aerial cable

It appears that using AMKA 3x120+95 on 0.4 kV has approximately the same restrictions as using AMKA 3x50+70 on 1 kV. Therefore, only AMKA 3x70+95 on 1 kV and AMKA 3x120+95 on 1 kV will be used in the evaluation.

To calculate the financial benefits of using 1 kV systems, we use the net present value (NPV) method, which is used in capital budgeting to analyze the profitability of an investment or project. NPV can be calculated by using eqn. 5:

(5) $$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_0$$

where: NPV – Net present value (€), C_t – Net cash flow during the period (€), C_0 – initial investment (€), r – discount rate, t - period number, T – number of time periods.

The initial investment can be calculated using eqn. 6:

(6) $$C_0 = C_{mv} \times L_{mv} + C_{lv} \times L_{lv} + C_S \times n_S + C_{Sw}$$

where: C_{mv} – unit cost of building a medium-voltage line (€/km), L_{mv} – length of the medium-voltage line (km), C_{lv} – unit cost of building a low-voltage line (€/km), L_{lv} – length of the low-voltage line (km), C_S – unit cost of the substation (€), n_S – number of substations, C_{Sw} – cost of the switching to connect to an existing network or substation (€).

Net income does not differ regardless of the solution provided to the customer. Therefore, net cash flows equal net expense that can be calculated using eqn. 7.

(7) $$C_t = \left((E_{MOHL} + E_{IOHL}) \times L_{lv} + (E_{MS} + +E_{IS}) \times n_s + E_D \times L_D + E_{EL} \times W_{EL}\right) \times (1 + CPI)^t$$

where: E_{MOHL} – base unit cost for the overhead power line maintenance (€/km), E_{IOHL} – base unit cost for the overhead power line inspection (€/km), E_{MS} – base unit cost for substation maintenance (€), E_{IS} – base unit cost for substation inspection (€), E_D – base unit cost for deforestation (€/km), E_{EL} – unit cost for energy loss (€/kWh), L_D – length of deforestation area for period t (km), W_{EL} – average energy loss for period t (kWh), CPI – average change in the consumer price index.

The alternative that provides the higher NPV is financially more feasible.

Obstacles and challenges in using 1 kV systems

1 kV low voltage system has been under evaluation in Finland and Sweden for some time and has proven its viability. The system is also in use in Norway and Latvia. Nevertheless, distribution networks form over a long period of time and no two systems are alike. Therefore, not all benefits and drawbacks that the 1 kV system presents exist in ELV network.

For example, in Finland over 90% of the network failures happen in the medium voltage network [2][6], while in ELV about 75% of the network failures take place in low voltage network. Finnish practice shows, that replacing a faulty underutilised middle voltage overhead lines with 1 kV aerial bundled cable, it is possible to decrease the total length of medium voltage lines in that area by 10-30% while at the same time increasing network reliability. In ELV, the effect would be much smaller, as most failures take place in low voltage network.

An important risk factor is the absence of a long-term experience with 1 kV systems. The first 1 kV system in Finland was built in 2001. Therefore, these systems have not yet proven, that they are reliable on a long term basis. Because 1 kV systems usually use components designed for 0.4 kV systems, it is unclear how it could affect the isolation. Finnish experience [2] shows that partial discharges can appear in AMKA type aerial overhead cables when ambient humidity is high. In underground cables, electrical treeing has been observed.

Another risk in using 1 kV systems is the possibility of confusing these lines with 0.4 kV lines, as the material in use is the same. Therefore, it could increase the time of fault localization. Labelling becomes even more important.

The overall use of 1 kV solution in ELV network depends whether or not the potential financial and non-financial benefits justify the drawbacks listed above. Therefore, it is necessary to find the number of potential customers or feeders, where 1 kV solution should be considered.

The potential benefit of using 1 kV solution

In order to show the possible benefits of using the 1 kV solution, the refurbishment of Holdre substation feeder 1 (Fig. 3) will be evaluated.

Fig. 3. Holdre substation feeder 1.

In all figures in this paper, green represents existing 0.4 kV power lines, red existing 15 kV power lines or substations, blue represents new 1 kV lines and substations, purple represents new 15 kV lines and substations and black represents all dismounted lines and substations.

According to ELV network standards, new medium voltage underground power lines have to be built next to the roads. New medium voltage overhead power lines are not used as the total lifecycle costs are equal or greater than those of the underground cable lines. 1 kV overhead lines have the potential benefit of using existing poles, which cannot be used in medium voltage systems (they are too short).

The first alternative is to change the existing 0.4 kV power lines with an aerial bundled cable. However, because the distance from Holdre substation is 2335 m, this solution would not meet current network standards.

The second alternative is to change the existing 0.4 kV power lines with an aerial bundled cable and use it on 1 kV, then add a new substation at the end of the feeder (Fig. 4). Almost all existing poles have to be changed. In total, 2240 m of aerial bundled cable, one new substation and two transformers (15/1/0.4 kV and 1/0.4 kV) are needed. A total of 1460 m runs through a forested area. The initial investment cost for this solution is 52 263 €. In addition, the present value of the total lifetime expenses for this alternative is 22 645 €. Large expenses are mostly due to the deforestation costs. Therefore the total cost for the company is 74 908 €.

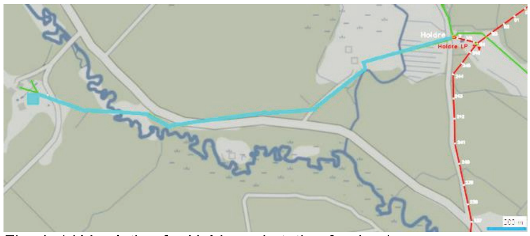

Fig. 4. 1 kV solution for Holdre substation feeder 1.

The third alternative is to build a new medium voltage underground power line and a new substation area for the customers (Fig. 5).

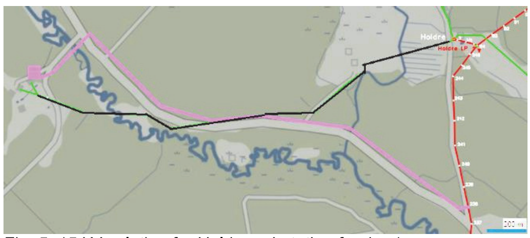

Fig. 5. 15 kV solution for Holdre substation feeder 1.

The total length of a new medium voltage power line is 2624 m. In addition to the underground cable, medium voltage switching, one new substation and a transformer (15/0.4 kV) are needed. 0.4 kV power lines (except for the connection between customers) is dismounted. The initial investment cost for this alternative is 79 582 € and the present value of the lifetime costs for the company 4 576 €. Therefore the total cost for the company is 84 158 €.

The final results for either alternative are presented in Table 1.

Table 1 Initial investment and lifetime expenses of either alternative

Solution	Initial investment, €	Lifetime expenses, €	Total expenses, €
1 kV solution	52 263	22 645	74 908
15 kV solution	79 582	4 576	84 158
Difference	- 27 319	18 069	- 9 250

Therefore, using 1 kV solution would save ELV 9 250 € on the total lifetime expenses of this system. That is a significant 11 % of the total cost of the 15 kV solution that would currently be used.

There are also other possible benefits. One of the first 1000 V distribution systems that was built in Estonia in 2007, is situated in North-Estonia near Tallinn in Harku parish. 1 kV system was chosen because distances were too long for standard 0.4 kV system and required voltage quality could not be guaranteed. Also, a new medium voltage overhead line could not be built, as Estonian Law of Electrical Safety stated that mass gathering events (for example sports competitions) are prohibited in the protection area of high-voltage (>1 kV line-to-line) overhead lines.

Final evaluation for 1 kV systems in Elektrilevi OÜ

Using the approach provided in this paper, all potential customers whose connection could be refurbished using 1 kV systems were located. Only customers who are located farther than 1 km from the substation were under evaluation. The total number of these customers is 7185. The energy consumption of 861 of those customers has been zero during the past year and are therefore excluded from sample. From the remaining 6324 customers, only 461 can be refurbished using a 0.4 kV solution. 1877 customers are situated either too far from the substation or the nominal current of their feeder circuit breaker is too high even for 1 kV solution. The remaining 3986 (Table 2) is the total number of potential customers, whose power supply could be refurbished using 1 kV solution.

Table 2 Number of potential customers by cable type suitable for refurbishing

Type	No. of customers
AMKA 3x70+95 1 kV	1193
AMKA 3x120+95 1 kV	2793
TOTAL	3986

As there are often more than one customer on each feeder, the number of potential feeders should also be analyzed. Using the same criteria as for the customers, the resulting number of potential feeders suitable for refurbish using 1 kV system, is 2474 (Table 3).

Table 3 Number of potential feeders by cable type.

Type	No. of feeders
AMKA 3x70+95 1 kV	922
AMKA 3x120+95 1 kV	1552
TOTAL	2474

There are a large number of potential customers and feeders, where using 1 kV solution could benefit the distribution network company and therefore in the authors' opinion ELV would benefit from using this system.

Summary and outlooks

To conclude, this paper provides an approach to evaluate the potential use of 1 kV solution as a cost effective alternative. The maximum length of a 0.4 kV feeder depends on the current of the fuse at the start of the feeder and the dimensions of the power line. Two restrictive factors were considered in finding the maximum length of 0.4 kV feeders: minimum one-phase short-circuit current and the maximum admissible voltage drop (5% in Elektrilevi OÜ).

This approach was used in Elektrilevi OÜ, where a total of 3986 customers and 2474 feeders were found to be potentially suitable for 1 kV system. As the example provided in this paper showed a significant saving on the total lifetime costs, the authors recommend using 1 kV solution in Elektrilevi OÜ.

There are two important topics that need future study. Firstly, before starting to implement a new voltage level, the distribution network needs to find the exact breaking point or the number of substation areas using the new voltage level needed, to overcome the drawbacks of 1 kV systems. Secondly, as 1 kV solutions and off-grid systems target the same customers, further study is needed to determine which system the distribution network should concentrate on.

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