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Optimization of Capacitor Banks in the Skagerak Networks Transmission Grid

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Abstract

Capacitor banks have been widely used in electric power networks. This master thesis presents a study of introducing new capacitor banks into a transmission network. The network comprises two areas at Telemark and Vestfold with voltages levels of 55kV, 66kV and 132kV, owned by Skagerak Nett AS.

Capacitor banks improve the electric network in five ways: power factor correction, increased capacity, reduction of losses, voltage support and reactive power support. International standards and regulations regarding capacitor banks usage, as well as technological related considerations, have been explained.

Network improvements are always required. The main goal of this project is to find an optimum solution for the installation of new capacitor banks in the Skagerak Nett network. The optimal solution is the one that minimizes cost of operation of the grid and investment in capacitor banks. The project aims to find the optimum solution for the whole network and the analysis includes the economic viability of the solution.

The optimum capacitor placement problem consists of determining sizes and location of capacitor banks in order to optimize an objective function. The problem is solved using various genetic algorithms. Genetic algorithms are implemented with Python, which can use the capabilities of PSS/E, where the network data is stored.

The objective function includes data from high load season, investment costs, power losses, reactive power losses and maintenance. The constraints of the problem limit the voltage, power factor and capacitor bank power. Economic aspects are also part of the objective function.

The results show that the electric power networks under consideration can be improved with the introduction of capacitor banks and that costs are reduced. The investments in the capacitor bank solutions are recommended as they offer savings respect the no investment option. The proposed capacitor bank configurations consists of 14 and 13 capacitor banks in Telemark and Vestfold, distributed in 7 and 10 transformer stations respectively, with power ratings that range from 6 to 20 Mvar. The savings of both proposals have been estimated to 68 and 40 MNOK during the investment period.

Resumen

Los bancos de condensadores han sido usados ampliamente en redes electricas. Esta tesis de master presenta un estudio de la implementacion de bancos de condensadores en la red de transporte. Las redes comprenden dos areas en Telemark y Vestfold con niveles de tension de 55kV, 66kV y 132kV, propiedad de Skagerak Nett AS.

Los bancos de condensadores mejoran la red eléctrica en cinco aspectos: corrección del factor de potencia, incremento de la capacidad, reducción de pérdidas, soporte de tensión y de potencia reactiva. Estándares y regulaciones internacionales relacionadas con la aplicación de bancos de condensadores y consideraciones tecnológicas han sido expuestas.

Mejoras en la red son siempre necesarias. Esta tesis de máster es el proyecto de planificación de bancos de condensadores. El objetivo principal es encontrar la solución óptima para instalar bancos de condensadores en la red. La solución óptima es la que minimiza los costes económicos de operación de la red y las inversiones en bancos de condensadores. El proyecto se dirige a encontrar la solución óptima en la totalidad de una red y a analizar la viabilidad económica de esta solución.

El problema de la óptima localización de bancos de condensadores consiste en determinar las potencias y las locaclizaciones de los condensadores que optimizan la función objetivo. El problema se resuelve usando varios algoritmos genéticos. Los algoritmos genéticos son implementados con Python, que puede usar las funcionalidades de PSS/E, dónde los datos de la red són almacenados.

La función objetivo incluye datos de temporada alta demanda, costes de inversión, pérdidas de potencia, perdidas de potencia reactiva y mantenimiento. Las restricciones del problema limitan tensión, factor de potencia y potencia de bancos de condensadores. Los aspectos económicos forman parte de la función objetivo.

Los resultados muestran que las redes eléctricas en consideración pueden ser mejoradas con los bancos de condensadores y que los costes son reducidos. Las inversiones en bancos de condensadores se recomiendan ya que ofrecen beneficios respecto la situación actual. Las configuraciones de bancos de condensadores propuestas consisten en 14 y 13 bancos de condensadores en Telemark y Vestfold , distribuidos en 7 y 10 estaciones transformadoras respectivamente, con potencias nominales desde 6 a 20 Mvar. Los ahorros de las propuestas han sido estimadas en 68 y 40 millones de coronas noruegas durante el periodo de inversión.

Preface

This Master Thesis is the project completed in ENE500, which is the final subject in the Master in Renewable Energy at the faculty of Engineering and Sciences at the University of Agder (UiA) in Norway. The project is a collaboration with Skagerak Nett, which is interested in a study of planned deployment of capacitor banks in its networks.

I would like to thank Knut Rydland and Tor Eriksen as supervisors in Skagerak Nett, for their dedication and support. All network data and the PSSE software provided by Skagerak have been the core tools in this project. My gratitude also goes to Skagerak Nett, that participated in the lectures of Smart Grids at UiA, and to all the professional staff I met at the company headquarters.

I would also like to thank Stein Bergsmark for his dedication as supervisor at UiA. In a broader sense, as an exchange student, I want to thank all the teachers that I have had in this academic year 2012-2013. And also I thank the other staff and the institution UiA for the help and resources that made this project possible.

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Acronyms

AC Alternate Current. 9, 10

CB Capacitor Bank. xiii, xv, 4, 7, 12, 16–28, 30, 39–41, 43–51, 55–59, 63, 64, 66, 68, 70, 73, 105

CBC Capacitor Bank Configuration. xiii, 25–36, 39, 44–46, 48, 55–57, 61, 66, 68, 70

CMLGA $\mu, \lambda-$ Genetic Algorithm. 7, 35, 65, 69, 75

ESGA Elitism Selection Genetic Algorithm. 7, 65, 69

FACTS Flexible AC Transmission System. 1

GA Genetic Algorithm. xiii, 6, 31, 35–38, 44, 67

MPLGA $\mu + \lambda-$ Genetic Algorithm. 7, 35, 65, 69, 75

OCP Optimal Capacitor Problem. 4, 6, 7, 25–27, 29, 30, 37, 45, 50, 61, 63–66, 69

OF Optimization Function. 33

PF Power Factor. 1, 10, 12, 13, 18–20

PSS/E Power System Simulator for Engineering. xv, 6, 26, 40, 41, 44, 45, 64, 75, 111

p.u. per unit system. 12, 13

RP Reactive Power. 10

SN Skagerak Network. 2, 6

TN Telemark Network. 41

TSO Transmission System Operator. 1, 19, 39

VN Vestfold Network. 41

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Chapter 1

Introduction

1.1 Background

Compensation of reactive power in power systems is an important issue in the development of the grid. Several technological solutions are used around the world. This master thesis deals with capacitor banks for compensation of reactive power. These are the most commonly used devices for that purpose. Capacitor banks can be installed in parallel or series to the power lines, and also can be combined with power electronic controllers as part of Flexible AC Transmission System (FACTS). They are installed in transformer power stations to raise Power Factor (PF) close to unity.

Consumers of reactive power are mainly factories, industries and large companies. Reactive power does not produce a net transfer of energy but it is needed to run electric motors for example. Companies and electric utility companies are charged by the use of reactive power. Reactive power load the lines and hinder active power energy flow. This is one of the reasons why utilities and consumers have to use compensation devices or sources of reactive power. Capacitor banks are used on different levels in the electric network. Firstly, the large customers install their own capacitor banks to reduce the bill from the utility company. Secondly, utility companies use capacitor banks in distribution networks as a means to maintain voltage levels. Thirdly, utility companies with transmission and subtransmission lines use them to produce reactive power consumed by transmission lines and to keep voltage levels within the limits.

When the utility company wants to improve or expand the network, a study is needed on where to place new equipment: lines, transformers, capacitor banks among other devices. Capacitor banks placement and sizing is a part of this network planning. In this project this planning will be made for the Skagerak Nett AS networks at Telemark and Vestfold regions. These networks already contain capacitor banks.

The subject of this thesis is to perform an optimization analysis to find out if, and how much, the network will benefit from placement of new capacitor banks. Skagerak Nett AS (SN) is the owner, operator and manager of the power transmission and distribution network in Telemark and Vestfold. SN prefers to evaluate the possible reduction in total costs with regards to reactive power management, based upon reactive power production in their own capacitor banks and by purchasing reactive power from the Transmission System Operator (TSO) of Norway, Statnett. Shunt capacitors with various switching capabilities are already installed at some transformer substations; however no complete optimization study has been made.

Although it is common to use capacitor banks in networks, a analytical study should be carried on, in order to continue developing the grid and to find the best locations and sizes of the capacitor banks, regarding best performance, reduction of costs and *pay back*.

1.2 Objectives

The main goal is to find optimum placement and sizing of capacitor banks in the Skagerak network transmission grid.

The underlying objectives are:

- For a specified set of constraints, find the near optimum placement and sizing of capacitor banks in the transmission network (55, 66, 132kV) of Skagerak Nett.
- Review of guidelines and regulations concerning capacitor banks in the power grid system.
- Study of economic aspects and technological limitations such as investments and harmonic resonance. Study of reactive power purchasing to Statnett by SN.

1.3 Scope and limitations

The study of optimum placement of capacitor banks will be made in the subtransmission network (66-132kV), which is a mesh network. So the placement of capacitor banks will be limited to the transformer stations located in this network that are property of SN. Reactive power compensation in the distribution network will not be considered to the consumers level. Rather, the end-users are included as loads in the transmission substations. Technological and economic constraints and guidelines are not limitations, as these will be considered in the analysis of the practical solutions for Skagerak Network (SN). Some data may be ignored which do not have significance for the study; for example transformer losses and reactive power consumption by transformers.

1.4 Problem Statement

The problem consists on finding the right locations and sizes of capacitor banks within an electric network in order to optimize their performance. In optimization, the choice of location and sizing becomes a search for the best solution. The way to decide if a set of capacitor banks is better than another set is also part of the problem. At the same time, the choice is restricted by electric network constraints. The sizes of capacitor banks are given by standard industry size, which, makes the set of solutions to be discrete. Therefore, the problem is classified as a discrete optimization problem.

The complexity of the problem arises from two aspects. The constraints of the problem, which make the solutions difficult to find if they have to satisfy many requirements. Mainly the complexity comes from the size of the network. The size of the network can make the search space grow to limits where it is not viable to screen it exhaustively. This means that a brute-force search algorithm is in most cases impractical. Brute-force search approach is only possible in small networks.

For example, suppose there are fifty power stations in the network available to install a capacitor bank, and that into each of the power stations you can place capacitor bank of ten different sizes. Then the number of possible combinations of capacitor banks in the network is 10^{50}. With a brute-force search, it will last around 10^{32} seconds with a supercomputer, which is much more than a lifespan. The key here is to find a optimum solution in a practical span of time.

In this project, the optimal combination of new capacitor banks is the objective. The meaning of optimum solution will be defined in Chapter 3. But now a short introduction to optimization problems will be presented. This leads to the following problem statement:

> Given a *electric network* with known *loads* and *power sources*, find the *set of new capacitor banks* that installed in *selected power stations*, *minimize the costs* for a certain *time period* and satisfy the *network constraints.*

Here the key terms that defines the problem have been highlighted. The electric network and the costs determine the form of the objective function, which has to be minimized. The set of capacitor banks and their locations are the variables that define the minimum solution.

In optimization problems with constraints, there is one or more functions that we want to minimize (or maximize). In this case, we want to minimize the function that represents the losses, the investments, operational cost of each combination of capacitor banks and cost of reactive power. The given network contains the data of power consumption and voltage profiles.

A optimization problem with constraints can be stated as follows [35].

$$\min_{\mathbf{u}} F_i(\mathbf{x}, \mathbf{u}) \quad i = 1, \ldots, k_1 \tag{1.1a}$$

Subject to

$$g_i(\mathbf{x}, \mathbf{u}) = 0, \qquad i = 1, \ldots, k_2 \tag{1.1b}$$

$$h_j(\mathbf{x}, \mathbf{u}) \leq 0, \qquad j = 1, \ldots, k_3 \tag{1.1c}$$

where,
$\mathbf{x}(\mathbf{u}) = (x_1, ..., x_m)$ is the set of dependent variables of the network: voltages magnitudes and phases, power loads and line parameters,

$\mathbf{u} = (u_1, ..., u_n)$ is the vector of independent control variables,

$F_i(\mathbf{x}, \mathbf{u})$ are the objective functions to be optimized [1],

$g_i(\mathbf{x}, \mathbf{u})$ are functions defining the set of equality constraints of the network: power flow equations (2.11), and

$h_i(\mathbf{x}, \mathbf{u})$ are functions defining the set of inequality constraints of the network: voltage ranges, active and reactive power limits, security constraints, harmonic distortion, etc.

[1] If there is more than one function to minimize then the meaning of minimization is

In this project the control variables u_i are the reactive power quantities generated by the capacitor banks at each bus. Usually the optimization is comprised of a single function F, although in some cases it can be composed by several functions, like for example voltage deviation, power losses and costs of capacitor banks. The most common approach combines several functions in a singular one in a way that all of them are evaluated in terms of monetary values. So for example, the function F can be the sum of the costs of: power losses, capacitor banks, operation and management, reactive power production and reactive power purchasing. The costs are evaluated during a certain period of time.

One of the difficulties is that there is not a single OCP, it can take several forms depending on the definition of the constraints and the objective function. The problem can become more difficult as more constraints are added. These constraints depend on the real network under consideration.

The network is composed by swing buses, PV buses (where voltage is maintained at a constant value), and PQ buses. Slack buses are reference buses where the voltage level and phase is given. The interconnections with the major grid are represented by swing buses, where the power needed flows to the network. PV buses are buses where the voltage magnitude is given but not the phase. The power flow through the network depends on the capacitor bank configuration. In consequence, the power flow have to be calculated when one wants to know the performance of a specific capacitor bank set.

1.5 Other Approaches

Some approaches that are not in the scope of the project but can be used as a model for optimization, are

- Use figures of several network conditions during the year (e.g. summer and winter seasons).
- Reallocation of CBs.
- Consideration of associated problems to Optimal Capacitor Problem (OCP) (3.1.4).
- Use of daily load figures.
- Consider the OCP on the distribution network.
- Modify or use other constraints for OCP.
- Include harmonics in the calculations.

1.6 Literature Review

Implementation of CBs in the electric network is regulated by national standards and international standards IEEE. In *Shunt capacitors for a.c. power systems having a rated voltage above 1000 V - Part 1*, [2], regulations and limitations are exposed. In [25, 24], the IEEE states the current international guidelines that are assumed by national governments and electric utility companies. Statnett as a TSO regulates operation and regulation of the grid. In [44, 45, 46] the regulations and tariffs for reactive power are stated.

Research on the optimal capacitor problem started in the second half of 20th century [15]. The research started with simplified assumptions for the OCP. For example, OCP in radial distribution systems, which can be solved with dynamic programming. The problem recovered interest in the nineties when new computational methods could be applied with faster computer processors [14], for example genetic algorithms. The proposed methods to solve the OCP can be divided in three types: analytical methods, optimization methods and computational intelligent methods [14].

Analytical methods use classic techniques to find extrema of analytic functions. For example Newton's methods or gradient descent. The problem is that it must be assumed that the objective function is continuous with respect to the control variables. Even more, the solution may not fit with standard industry capacitor banks sizes.

Optimization methods are algorithms applied extensively in several fields: linear programming, non-linear programming or dynamic programming. They can only solve the problem with some simplifications not considering the whole optimization problem.

Heuristic methods use some random procedures in order to find the optimal solution. Heuristic means that the algorithm procedures are not based in fail-safe decisions in the search of the optimal solution. They are also known as stochastic optimization methods. In contrast with deterministic algorithms, their goal is to find near optimal solutions, not the absolute optimal solution. There are many methods in this family that includes: fuzzy optimization, evolutionary algorithms, ant colony algorithms and particle swarm optimization. All of them have been used in the OCP [20]. Computational intelligent methods are based in heuristics. They can not find a global optimum solution but one that is close enough to it. Some of this types of methods have been combined in a single algorithm to achieve better solutions or to decrease computational time.

Usually in optimization problems the deal is to find the global minimum or maximum of the function (see fig. 1.6). Some algorithms need to be run more than once to assure solutions are not local extremes. Genetic algorithms have shown good results in finding global extremes ([32], [33]).

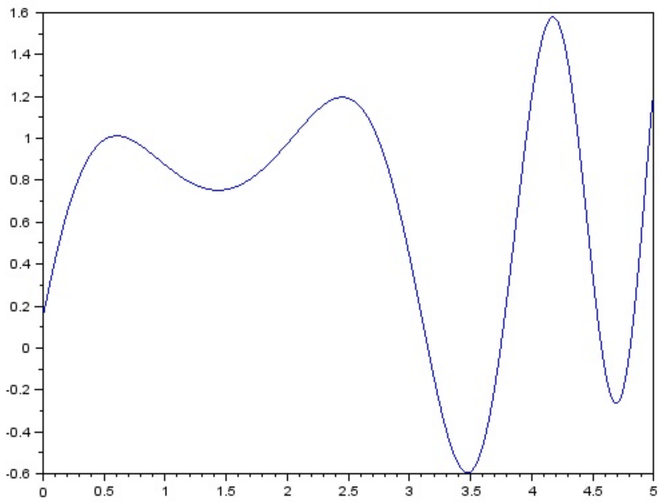

Figure 1.1: Graph of an objective function with local minimums at 1.5 and 4.7 and one global minimum 3.5

1.7 Solution Approach

Different solving methods can be applied depending on the size of the network. For instance, in networks with less than ten nodes, a brute-search algorithm can be applied. Networks with more than ten nodes are better solved with the methods mentioned in section 1.6. So three methods can be applied: dynamic programming, gradient less method and genetic algorithms. Ii is worth saying that these methods can have multiple variations. Justification of the methods will be given in Chapter 3. The objective is not to test the reliability of the methods, but to find and contrast optimal or near-optimal solutions.

The dynamic programming method has been first used in the 1950s. These algorithms can only be applied to particular networks. In [20] the authors present a deterministic algorithm for OCP in radial distribution networks. They develop an extended dynamic approach that is based in the dynamic programming algorithm proposed by [15].

The gradient less method is an analytical method. Analytical methods use calculus techniques to find the minimum of an analytic function, which is the objective function to optimize. Some of them require to compute the gradient of the function and some of them not. One disadvantage of this methods is that they can not provide solutions with standard capacitor sizes. There exist algorithms that combine analytic methods and heuristic methods [20].

Genetic algorithms are a family of algorithms that applies genetic evolution principles to create programs that can find a near-optimal solution. Genetic algorithms are used extensively in electric power systems [35] and other engineering fields [33]. They have been used for the OCP: [37] makes a study of a sub-transmission network, [32] applies GA to two standard IEEE networks and compares it with other methods, [13] applies GAs with a multi-objective function to a real network in Brazil, and [11] makes a technical and economical analysis in a real transmission network.

As is shown in [37], the algorithm is implemented in a programming language. The implementations of the algorithms to programming languages are extensive. The chosen one is Python, which offers several optimization libraries, one of them is dedicated to genetic algorithms. Python allows interaction with other programming languages. The most important feature is that Python can control a power system software like PSS/E. The advantage of PSS/E is that the networks under study are already implemented. PSS/E contains the parameters of the network: impedances, generators, loads, transformers. It calculates the power flow of a network and it returns losses, power produced, voltage levels, reactive power consumption.

In [37] they use DigSilent as the power system software for support to execute the algorithm. A drawback of using a power system tool is that it is only possible to retrieve information of the network, but in general, it is not possible to know the calculation that the program executes. In other words, the program is a black-box that gives the required outputs to specified inputs. In consequence, the objective function becomes also a black-box. Then it is not possible to compute the gradient of the function or the Hessian, which makes no possibility to use explicit gradient methods like the gradient descent method.

1.8 Thesis Contributions

The main contribution of the project is a program implemented with Python, making use of PSS/E in order to solve the OCP in any electric network. The program has several options that allows to analyse the results. The second major contribution is the implementation in the algorithm, the constraints of the SN electric transmission network. The third contribution is to implement guidelines and regulations of capacitor banks in the program.

The productive algorithms are a Elitism Selection Genetic Algorithm (ESGA), $\mu, \lambda-$ Genetic Algorithm (CMLGA) and $\mu + \lambda-$ Genetic Algorithm (MPLGA). The whole program uses them with the constraints of the OCP: voltage levels, power factor, minimum and maximum number of CBs and maximum reactive power supply.

Elitism selection has been implemented in ESGA. The solution codification has been also adapted to the OCP. The entire program becomes a software tool to solve this problem. In addition, the program includes functions to check the constraints.

1.9 Report Outline

The second chapter makes an introduction to capacitor banks, description of types and regulations. The third chapter explains the algorithms used to find the solution. Chapter 4 describes the networks to be optimized and the solutions obtained with the algorithms. Chapter 5 analyse the solutions for Telemark and Vestfold, and in Chapter 6 a discussion of the results is carried on.

Chapter 2

Capacitor Banks

Capacitor banks were introduced in the electric grid during the first years of 20th century. At that time the electric network with alternating current soon become very large and losses caused by reactive power became a problem.

In this chapter an electrotechnical description of capacitor banks in electrical networks is presented. As the objective is to provide an optimal and practical solution for reactive power compensation using capacitor banks, guidelines and regulations will be presented here.

2.1 Capacitor Banks In Electric Networks

2.1.1 Reactive Power

In alternating current (AC) electric systems, voltage $v(t)$ and current $i(t)$ are sinusoidal waves with a phase difference ϕ[1]due to the impedance of the load. Electrical machines, based in electromagnetic transformation of energy like Alternate Current (AC) motors, are intrinsically loads with impedance.

$$v(t) = \sqrt{2} \cdot V \cdot \sin(\omega t) \tag{2.1a}$$
$$i(t) = \sqrt{2} \cdot I \cdot \sin(\omega t + \phi) \tag{2.1b}$$

The terms V and I are the root mean square values of $v(t)$ and $i(t)$. *Instant power* in a point of electric circuit is the product of the voltage and current. *Active power* is the average of instant power. It can be shown that using equations 2.1 that the instant power is

$$p(t) = VI\cos(\phi) - VI\cos(2\omega \cdot t - \phi) \tag{2.2}$$

The first term in $p(t)$ is constant. The second term is periodic with period π/ω, which means that

[1]A simplified exposition will be used, by now, as harmonics will not be considered and this is for three-phase and single-phase systems. General presentation without these assumptions can be found in [27].

its mean value in a period of $2\pi/\omega$ is zero. So the active power is

$$P = VI\cos(\phi) \tag{2.3}$$

The term $\cos(\phi)$ is called PF. Note that a load that consumes an active power P_0 at a rated voltage of V_0 will absorb more current I for a lower PF, as can be observed in next equation:

$$I = \frac{P_0}{V_0\cos(\phi)} \tag{2.4}$$

As a consequence, overhead lines with low PF will be more loaded and will have more ohmic losses. PF is a fundamental characteristic of electric machinery, AC motors in particular, and, as will be explained through this chapter, it is a major concern for large consumers and electric power companies.

Aparent power is the product of V and I and is denoted by S. Its units are called volt-amperes, VA.

Given an active power at a given voltage and current with a certain PF, Reactive Power (RP) is defined as

$$Q = VI\sin(\phi) \tag{2.5}$$

It can be shown that

$$Q = \sqrt{S^2 - P^2} \tag{2.6}$$

so in this way, reactive power can be regarded as the apparent power that is not transformed into active power. Its units are reactive volt-amperes, var. Reactive power is also present in electric power systems and affects the current load on transmission, subtransmission and distribution lines.

To reduce consumption of reactive power the solution is to "modify the load" in a way that the PF is as high as possible. Capacitive loads can increase the power factor as the global impedance Z is modified by the capacitance C in next equation:

$$Z = R + j\left(\omega L - \frac{1}{\omega C}\right) \tag{2.7}$$

Another point of view is to consider capacitors as sources of capacitive reactive power. As is shown in figure 2.1.1, the reactive power of the original load, Q_0, is decreased by the reactive power supplied by the capacitor, Q_{CB}. As a consequence the PF is increased and the new current I_1 is lower than the original current I_0. Then the line is less loaded and the ohmic losses are reduced.

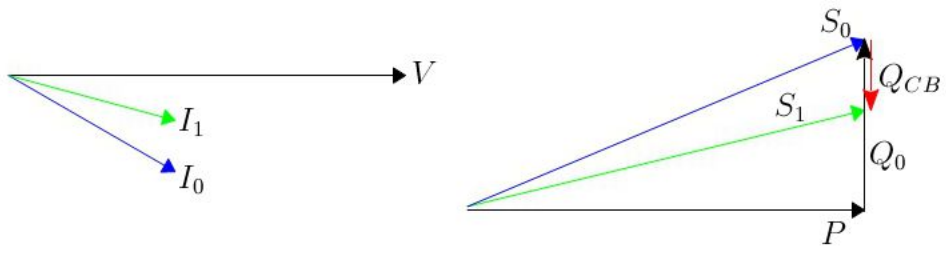

Figure 2.1: Power Factor modified by reactive power Q_CB from a capacitor bank

Equations (2.8) relate the voltages and currents of the two ends of a transmission line, R and S.

$$\begin{pmatrix} V_S \\ I_S \end{pmatrix} = \begin{pmatrix} \cosh(\gamma l) & Z_c \sinh(\gamma l) \\ \sinh(\gamma l)/Z_c & \cosh(\gamma l) \end{pmatrix} \begin{pmatrix} V_R \\ I_R \end{pmatrix} \tag{2.8}$$

Where γ is called *propagation constant* and Z_c is the *characteristic impedance* and are defined from the impedance per kilometer, z and the admittance per kilometer, y.

$$\begin{aligned} \gamma &= \sqrt{yz} \\ Z_c &= \sqrt{\frac{z}{y}} \end{aligned} \tag{2.9}$$

The following equations will be written with this notation:

$$\begin{aligned} A &= D = \cosh(\gamma l) \\ A &= |A|\underline{/\alpha} \\ D &= |D|\underline{/\alpha} \\ B &= Z_c \sinh(\gamma l) \\ B &= |B|\underline{/\beta} \\ C &= \sinh(\gamma l)/Z_c \\ V_R &= |V_R|\underline{/0} \\ V_S &= |V_S|\underline{/\delta} \end{aligned} \tag{2.10}$$

An important value to control the electric network is the flow through the line between to buses. The receiving bus is labelled as R and the sending bus as S. Bus R receive an apparent power S_R from S, and bus S transmit an apparent power S_S towards R. These values are given by equation 2.11, [26].

$$S_R = \frac{|V_R||V_S|}{|B|}\underline{/(\beta - \delta)} - \left|\frac{A}{B}\right| |V_R|^2 \underline{/(\beta - \alpha)} \tag{2.11}$$

$$S_S = \left|\frac{D}{B}\right| |V_S|^2 \underline{/(\beta - \alpha)} - \frac{|V_R||V_S|}{|B|}\underline{/(\beta + \delta)} \tag{2.12}$$

The real and imaginary parts of this values indicate the active and reactive flow through the line. A positive sign indicates the bus is consuming power (active or reactive) from the other bus and a negative sign indicates that the bus is a delivering power toward the line and the other bus. The power losses in the line can be calculated with the difference of S_R and S_S. The equation for S_R can be developed in real and imaginary part to obtain the transmitted active power, P_R, and reactive power, Q_R:

$$P_R = \frac{|V_R||V_S|}{|B|}\cos(\beta-\delta) - \left|\frac{A}{B}\right||V_R|^2\cos(\beta-\alpha) \tag{2.13}$$
$$Q_R = \frac{|V_R||V_S|}{|B|}\sin(\beta-\delta) - \left|\frac{A}{B}\right||V_R|^2\sin(\beta-\alpha) \tag{2.14}$$

In a power network, the relation between the power produced (or consumed) at each bus and the bus voltages is given by equations 2.16 and 2.17, [26]. It is assumed that in the network of n buses the apparent power is represented as $S = P + jQ$, the voltages are $|V_i|\underline{/\delta_i}$ and $|V_j|\underline{/\delta_j}$, the admittance between buses i and j is $|Y_{ik}|\underline{/\theta_{ik}}$ and

$$Y_{ii} = \frac{B_i}{2} - \sum_{k=1k\neq i}^{n} Y_i k, \qquad i = 1,\dots,n \tag{2.15}$$

These equations comprise the system for solving the power flow problem in a electric network. At PQ buses the power in the bus is given and the unknowns are the voltage magnitudes $|V_i|$ and their angles δ_i. At PV buses the active power P_i and $|V_i|$ are given and the unknown is δ_i. One of the buses is the slack bus, where the voltage is set to $1\underline{/0}$ per unit system (p.u.). This makes a system of $2n_{PQ} + n_{PV}$ non-linear equations [2]. As a system of equations, the modification of one of the values of the power affects the whole system, producing a different solution. For instance, if a source of reactive power like a CB is set up in a bus, then the corresponding reactive power equation is modified, affecting the whole set of voltage magnitudes and angles.

$$P_i = |V_i|\sum_{k=1}^{n}|V_k||Y_{ik}|\cos(\theta_{ik}+\delta_k-\delta_i) \qquad i = 1,\dots,n \tag{2.16}$$
$$Q_i = |V_i|\sum_{k=1}^{n}|V_k||Y_{ik}|\sin(\theta_{ik}+\delta_k-\delta_i) \qquad i = 1,\dots,n \tag{2.17}$$

2.1.2 Reactive Power in the Electric Grid

The 3-phase electric systems under consideration are assumed to be balanced; each phase has the same power load and the same PF. To understand the need of reactive power to maintain voltage levels we can proceed with the following explanation.

The transmitted reactive power to a bus R is given by equation 2.14. Dividing this equation by $\frac{|V_R|^2}{|B|}$ and rearranging the terms the ratio $\frac{V_R}{V_S}$ can be isolated to obtain equation 2.18.

[2]The number of PQ buses is represented by n_{PQ} and the number of PV buses by n_{PV}.

$$\frac{V_R}{V_S} = \sin(\beta - \delta) \left(\frac{1}{|A| \sin(\beta - \delta) + \frac{Q_R}{|V_R/B|^2}} \right) \tag{2.18}$$

Equation (2.13) gives the active power transmitted to R. The value of β is usually close to 90 degrees because the resistance is established to low values by using high quality conductors [26, p. 162]. The variations on active power demand at the receiving end R are met by setting the angle δ to a certain value. The power grid works with specified voltages (or ranges of voltages) at each bus. Power system companies try to keep bus voltage close to their nominal values of 1.0 p.u. [34], which is affected by variations of reactive power demand as is explained below. The voltage drop at each bus can only be greater than 3 % for steady state operation and over 5 % for peak value, at 12 times of the day [31].

If an increase on the demand of reactive power Q_R happens, then, from equation (2.18), the voltage magnitude $|V_R|$ decreases, which can fall out of the limits. Similarly, if Q_R decreases, V_R increases. To avoid extreme variations, a source of reactive power can be installed at R, such that Q_R is always within the limits. Control of reactive power limits is an important issue in electric power systems. Uncontrolled reactive power consumption can lead the system to voltage collapse [26, 47]

Optimum power factor from the point of view of the consumer can be found through the analysis of the tariff [47]. Let C_P be the cost of one kWh and C_S the cost of a kVA. Then the total tariff for a load of P kW and S kVA is

$$C_P \cdot P + C_S \cdot S \tag{2.19}$$

Using equation (2.3), the present value of the apparent power is $P_0/\cos\phi_1$. If the power factor is increased (improved) then the new apparent power is $P_0/\cos\phi_2$. The saving is therefore [47]

$$C_S \cdot P_0 \left(\frac{1}{\cos\phi_1} - \frac{1}{\cos\phi_2} \right) \tag{2.20}$$

The cost of the reactive power required from the correcting capacitors is

$$C_C \cdot P_0 \left(\tan\phi_1 - \tan\phi_2 \right) \tag{2.21}$$

where C_C is the cost per annum in interest and depreciation on the capacitor installation in NOK/kvar. Therefore, the net saving, which shall be maximized is given by next formula

$$SA = \left[C_S \cdot P_0 \left(\frac{1}{\cos\phi_1} - \frac{1}{\cos\phi_2} \right) - C_C P_1 \left(\tan\phi_1 - \tan\phi_2 \right) \right] \tag{2.22}$$

The extreme is easily found to be ϕ_2^* such that $\sin\phi_2 = C_C/C_S$. Summing up, the customer will maximize his savings if he sets the reactive power sources such that the new PF is ϕ_2^*.

Reactive power is needed to maintain system reliability and to improve efficiency of active power transportation [40, p. 5]. Inadequate reactive power supply lowers voltage; as voltage drops, current must increase to maintain the power supplied, causing the lines to consume more reactive power and the voltage to drop further [40, p. 19]. Reactive power capability is cost that utility companies have to deal with. As reactive power supply has cost tradeoffs, power utility companies have to evaluate the suitability of investments

Capacitor banks are used as a source of reactive power. End-users, industry and electric lines are the consumers of reactive electric power. Devices used in the industry are electric motors, transformers, conductors, chokes, converters, arc furnaces and power electronics [27, p. 10]. Induction motors consume reactive power and have a large variety applications like air conditioners, household appliances, mining, industrial equipment and manufacturing processes. Underground and overhead transmission lines have inductance and capacitance, and can either supply reactive power or consume reactive power depending on the line loading. Generators can supply or consume reactive power within limits [40, p. 25]. Transformers and wind turbines are also consumers of reactive power.

As the active power demand, reactive power has a variable demand that depends on seasons, days and hours. Figure 2.2 shows a hypothetical daily reactive power demand where the peak is situated at the time the largest consumers of reactive power are operative.

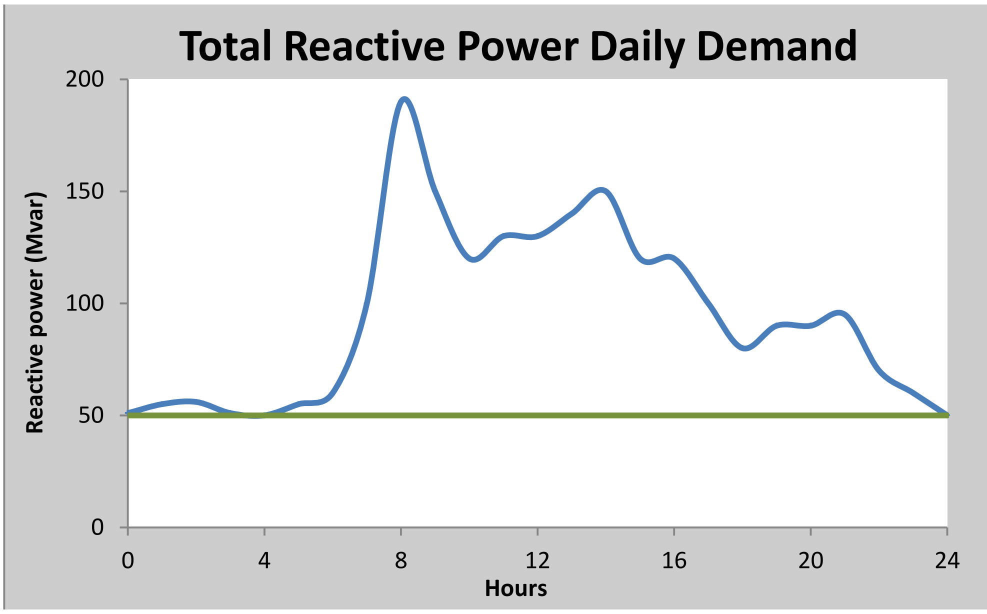

Figure 2.2: Reactive power demand curve, base demand (green), variable demand (blue). Based on [25].

2.1.3 Reactive power compensation technologies

There exist several sources of reactive power. The most valuable comes from synchronous generators because it has instantaneous response and is independent of the voltage [40, p. 24]. Whereas, capacitor banks lack of this features, they have a lower cost and easy maintenance.

Capacitors and inductors (or reactors) supply and consume static reactive power, respectively. These are called static devices since they have no active control of the reactive power output in response to the system voltage. On the other hand, synchronous generators, synchronous condensers, Flexible AC Transmission Systems (FACTS) including static var compensators (SVC), static compensators (STATCOM), and Dynamic Var (D-var) are considered as dynamic reactive power devices capable of changing their output according to pre-set limits in response to the changing system voltages [40, p. 24].

Synchronous generators can produce a definite quantity of active and reactive power (within some constraints). The production of reactive power can be adjusted in a short period of time (if the active power is kept constant and the generator is already running). However generators are expensive to maintain due to their mechanical parts and their cooling systems [40, p. 26]. Synchronous condensers are synchronous machines that are specially built to only supply reactive power. They can be made from old synchronous generators that are no longer economically productive. Supervar machines are synchronous condensers with high temperature superconductor technology that enables them to have a higher efficiency. Supervar machines are specifically designed for continuous, steady-state dynamic var support while having multiples of their rated output in reserve for transient problems [40, p. 29].

Transformers are used to interconnect these devices to the grid. As inductive machines they consume reactive power. They are also used to interconnect the various voltage grids. Tap changers can regulate voltage levels on both sides. As they adjust the voltages they are regulating at the same time the reactive power through them [40, p. 29].

Series capacitors are used in long transmission lines. They improve electricity transfer by reducing the electric distance of the line. They provide reactive power proportional to the square of the current [40, p. 34].

Flexible AC Transmission Systems (FACTS) are power electronic components installed in electric grids capable of monitoring and controlling different parameters like voltage, active and reactive power. Some of them are described below.

Static var compensators (SVCs) are shunt capacitors or reactors connected to the grid through thyristors that can control the voltage by supplying or consuming reactive power [40, p. 35].

Usually, a SVC is combination of one or more of the following branches: Thyristor Switched Capacitor (TSC), Thyristor Switched Reactor (TSR), Thyristor Controlled Reactor (TCR), Fixed Filter Circuit (FC). The function of TSC is to avoid voltage transients at switch-on of the capacitor banks. This is achieved with the precise triggering of the thyristor valves. They only provide a constant amount of reactive power. The same applies to TSR, which absorb reactive power in case of a light load [41]. On the other hand, the TCR supplies an adjustable reactive power by means of the phase-controlled thyristors. As it can generate harmonics, it is used in conjunction with the FC.

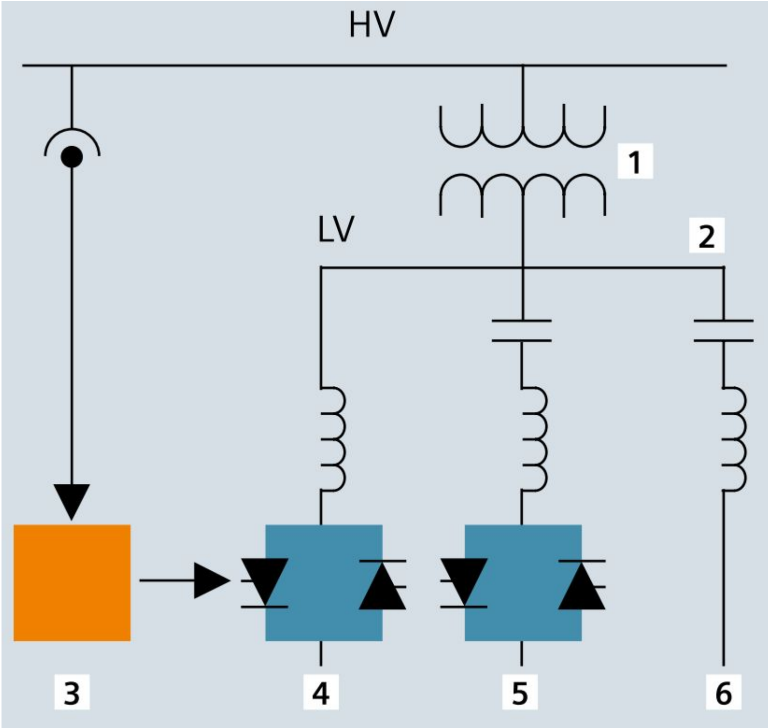

Figure 2.3: SVC system with various components: 1. Step down transformer, 2. LV bus bar, 3. Control, 4. TCR, 5. TSC, 6. FC [43]

Static compensators (STATCOM) convert a DC voltage to three-phase voltage with the desired phase and amplitude. They are used like synchronous condensers [40, p. 35].

D-var (Dynamic var) are a type of STATCOM that dynamically control voltage levels in transmission grids and industrial facilities, and detect and compensate electric disturbances. This systems are scalable and mobile, which means that their power can be upgraded upon necessities. They can be combined with capacitor banks to solve reactive power issues in wind farms [40, p. 37].

2.2 Capacitor Banks

Capacitor Banks (CBs) can be used in several ways within the electric power system. Some of them have been explained in the previous section. Capacitor banks connected in parallel to the grid are called shunt power capacitors. In this section its functions and characteristics are described.

CBs are classified regarding the connection to the electric network as shunt capacitor banks or series capacitor banks. The latter are used to modify the impedance of a transmission lines in order to achieve a more efficient electricity transmission. This project will deal solely with shunt capacitor banks because it is the technological device chosen (and already in use) for reactive power compensation[3].

CBs are made up of capacitor units, that in turn are composed by several capacitor elements (fig. A.1). Capacitor units have rated voltages from 240 V to 24940 V [7], combining them in series they can be designed for any voltage level. Capacitor units connected in parallel make up a group and

[3] In the following, shunt capacitor banks will be stated as capacitor banks

series connected groups form a single-phase capacitor bank (fig. A.2). When grouping capacitor units care have to be taken on the difference of capacitances not exceeding 15 % [2]. The number and configuration of capacitor units in the CB depend on the rated voltage, power and type of protection. Protection schemes of capacitor units are: external fuse, internal fuse, fuseless and unfussed. Upon failure of capacitor elements, protection is adjusted so that the unit can function with one or more fused elements. The protection acts if voltage levels on the capacitor unit are over 110 % of the rated voltage. Unbalance protection has to be adapted to the type of ground connection [7].

During daily heavy load periods, switched shunt capacitors are used to provide voltage support by injecting reactive power to the power system (fig. 2.2). Switched shunt capacitors are connected to the system through mechanical switches or circuit breakers and their real power losses are very small. Reactive power output from capacitors is proportional to the square of the voltage. This can be a problem during a contingency or a depressed voltage condition; as the voltage falls, the reactive power supplied by the capacitors decreases according to the square of the voltage, causing voltage to drop further. Fixed shunt capacitor banks are not switched in a frequent basis. They are switched manually or automatically twice per year from the dispatch centre using SCADA (K. Rydland, personal communication, 14 January, 2013, [25, p. 21]).

CBs are installed in a transformer substation, indoors or outdoors, which affects the operating temperatures that in turn determine the ratings [25, p. 15]. When a CB is switched out, it must be discharged before reconnection, normally with discharge time ranging from two to fifteen minutes. In special applications requiring switching-out and fast reconnection, the capacitor banks are equipped with fast discharge reactors that will discharge them in about 120 milliseconds, thus enabling them to be reconnected to provide voltage support to the power system [40, p. 33].

Table 2.1: Capacitor bank tolerances [2].

Tolerances	
–5 % to +10 %	for capacitor units,
–5 % to +10 %	for banks up to 3 Mvar total rating,
0 % to +10 %	for banks from 3 Mvar to 30 Mvar total rating,
0 % to +5 %	for banks above 30 Mvar total rating.

Table 2.2: Continuous operation conditions (based on [25]).

Continuous operation	Caused jointly by	Limited to
135% of nominal reactive power	Voltage in excess of nameplate rating 3rd or higher harmonics Manufacturing tolerance	110% of rated rms voltage 120% of rated peak voltage 135% of rated rms current

2.2.1 Benefits of Capacitor Banks

Capacitor banks in the electric grid provide voltage support, var support, increase system capacity, reduce system power loss and reduce billing charges. The first two are primary benefits for the transmission system, and the last three are important for the distribution system. Capacitor banks can be classified regarding their functions. Each of them can have some particular characteristics that are explained in next sections.

Voltage Support

Application of capacitor banks in the electric buses produce a rise of their voltages. The capacitor reduces the inductive current, which makes the voltage rise all the way back to the voltage source and beyond the capacitor location in a radial system.

The voltage rise at the capacitor location is approximately equal to the capacitor current times the inductive reactance of the system to the capacitor location, that is $\Delta V = I_C X_L$ [25, p. 6].

In the transmission system, CBs are installed at major buses to provide voltage support for a large area. If they are installed in distribution buses, they provide voltage support to smaller areas and to individual customers. CBs that are installed for voltage support are generally switched on during the peak loading periods or low-voltage conditions and switched off during light loading periods or high-voltage conditions. This is one of the uses of capacitor banks in Skagerak Nett networks.

Var Support

Reactive power (var) support means the features related to reactive power that a capacitor bank can work for. That is, improved voltage control and power factor; reduced system losses and reactive power requirements at generators; and increased steady-state stability limits [25, p. 7].

This is the main function that we want to use for the purpose of the capacitors that are intended to be installed in the Skagerak Nett networks. However, capacitors should be sized and located properly at transmission and distribution substations to supply the optimum reactive power. Unfortunately, reactive power can not travel long distances [40].

System Capacity

The electric grid is loaded by power voltamperes. Which means that the current, within the reactive current, occupies the space in the conductor. CBs reduce reactive current flow, and thus releasing capacity that can be used if an increase of system capacity is needed. The optimum economical power factor for a system, with regard to released capacity only, can be estimated with formula (2.23) [25, p. 7].

$$PF = \sqrt{1 - \left(\frac{C}{S}\right)} \tag{2.23}$$

where C is the cost per kilovar of capacitor, S is the cost per kilovoltamperes of system equipment and PF is the optimum power factor.

If there is the need to release a desired amount of system kilovoltamperes (S_{re}, in p.u. of existing kilovoltamperes), the new power factor needed is given by next formula [25, p. 8].

$$PF_{new} = \frac{PF_{old}}{1 - S_{re}} \tag{2.24}$$

The amount of kilovars needed to modify the PF is given by next formula [25, p. 8].

$$Q_c = P\left(\tan\left(\arccos(PF_{old})\right) - \tan\left(\arccos(PF_{new})\right)\right) \tag{2.25}$$

Power Losses

The inductive current is reduced by the capacitor banks and therefore the current flow through the system is reduced. Then conduction losses in lines are reduced. The power losses are proportional to the square of the current, so the reduction of current has a greater effect in losses. The efficiency of the system is then improved, which means that energy production is diminished and energy resources are saved. This is the second main goal we are pursuing with the installation of CBs.

The inductive current supply is associated with the variation of PF. So, if for example a client increases the PF, the ratio of the system losses associated with its load with and without CBs can be estimated with next formula [25, p. 10].

$$\text{Loss ratio} = \frac{\text{Loss with capacitors}}{\text{Loss without capacitors}} = \left(\frac{PF_{old}}{PF_{new}}\right)^2 \tag{2.26}$$

Billing Charges

Utility companies charge their mass-consumption customers for reactive power consumption. Usually, industries and other big companies acquire power devices to reduce this consumption. They can also make agreements with the utility company in such a way that the reactive power consequences are palliated.

The kilovoltampere billing charge may be calculated in many different ways [25, p. 10]:

1. A fixed charge for each kilowatt plus a fixed charge for each kilovar.
2. A certain charge for each kilowatt at or above a certain power factor, with additional charges made for each kilovar in excess of that required by a minimum power factor.
3. A charge per kilowatt demand multiplied by a factor that increases with decreasing power factor.
4. A fixed charge per peak kilovoltampere.

In Norway, the TSO (Statnett) charge for excess of reactive power demand for each step of ± 5 Mvar [44, p. 6]. Each kvar is charged with 30 NOK. So if a utility is consuming ±24 Mvar it will pay 720000 NOK. To settle the value of the reactive power that has to be charged, five measurements are made in five control hours for the heavy load and light load seasons. The highest values of each season are taken as the reactive power to be charged. The measurements are made at each exchange point of the national grid. When there are more than one point, the net exchange is measurement under consideration. The heavy load period lasts from 1st of November until 31st of March.

2.2.2 Types of Reactive Power Compensation

The electric network is divided in three different areas: distribution, transmission and regional[4], which are interconnected by transformers. The distribution network is a radial network that comprises the low voltage levels (230V - 1000V)[5] and the medium voltage levels (1kV - 11kV). Residential and commercial customers are connected to low voltage levels and small industrial customers to the medium voltage level. The transmission network consist of voltage levels from 11 kV to 132 kV and its function is to transmit electricity from generation plants to customers and to connect with the regional network. It is a mesh network in order to avoid supply interruption when contingencies happen. The regional network, which comprises the very high voltage levels (more than 132 kV), is controlled by the TSO and its function is to interconnect utility companies and electric power plants.

In a large electric network that comprises several voltage levels, CBs can be installed in these different levels in order to take advantage of the benefits mentioned above. However, CBs have different characteristics and functions depending on the setting place. In this way, the types of compensations with CBs are: fixed, group and bulk [27].

Fixed compensation consist of CBs installed next to or within the load. The sole purpose of the CB is to compensate the reactive power of a single load with a low power factor (for example an induction motor). The capacitor compensation can be programmed to work when the load is on. The costumer avoid billing charges for reactive power.

Group compensation is used when reactive power from several loads is aimed to be compensated. This compensation can be used by large customers like industries or office buildings, in order to increase the power factor. The CB provide the reactive power consumed by several loads at the same building or installation. This customers can avoid in this way being charged by the utility company. The capacitor bank power can range from 1-100 kvar for small companies to 1-10 Mvar for large factories. Each company can settle several CBs in its premises with different characteristics or working hours. An efficient option are CBs with taps that automatically set the right reactive power according to the desired PF. The customer avoid billing charges and reduce the rated current of protection equipment. Electric utility companies use this type of compensation in the distribution network when they need to compensate neighbourhoods with a large amount of customers [22]. As the compensation is close to the loads, this is the more efficient way to supply the reactive power they require [25, p.][6]. The main benefits of group compensation are voltage support and reduction of losses.

Bulk compensation is used in the transmission network by utility companies in order to compensate reactive power consumed in feeders. The CBs are placed in transformer stations, the global load connected to that station are partially or totally compensated. In this way the load on the lines that feed the transformer are less loaded. This is the type of compensation used in the transmission network. It is compatible with the other types of compensation. The benefits of this type of compensation are system capacity, voltage support, var support and reduction of power losses. Compensation at transmission and subtransmission networks can be regarded as bulk compensation.

Table 2.3 shows a summary of advantages and disadvantages of the different types of compensation.

[4]Voltage levels can be different from region to region and country to country.
[5]Other nomenclature is used by other sources: distribution, subtransmission, transmission, regional transmission.
[6]However this compensation will have little effect on the transmission network [40].

Table 2.3: Advantages and downsides of the three types of compensation

Type of compensation	Advantages	Disadvantages
Fix	Simpler, safer, reduction of losses in distribution network, automatic CB.	Need of many CBs units. It does not compensate parts of the grid and it only work when the compensated machine is on.
Group	Less CBs needed and it compensates some parts of the grid	More expensive than bulk compensation and it needs an electronic controlling device.
Bulk	Most cost effective and the minimum CB units	Expensive CBs (with insulation) and switching can not be frequent.

2.2.3 Comparison of Reactive Power Sources

Dynamic reactive power sources are more expensive than static reactive power sources. According to [40, p. 38] "the capital costs of static sources of reactive power, such as capacitors, are orders of magnitude lower than the capital costs of dynamic sources, such as generators, SVCs and synchronous condensers". In addition capacitor banks and switches have relatively low maintenance costs [40, p. 34]. For example, synchronous condensers are only viable to be used in buses with high demand of reactive power [26, p. 177].

One disadvantage of capacitor banks is that their "reactive power has a slow response and declines with the square of the voltag" [40, p. 24]. Compensation by CBs present some other drawbacks: resonance, harmonic resonance, switching transients (section 2.3) and overvoltages [17, Ch. 10]. Capacitor banks tend to rise voltage levels. This can cause overvoltages when the load lows to valley hours. To avoid damages in the electric network, CBs (specially the switched ones) have to be monitored from the dispatch center.

The advantages of capacitor banks are mainly located in the costs part [40, p. 39]. When capacitor banks satisfy the operating necessities of the grid and no other features are planned to be used, capacitor banks should be considered as the first option. Even more, when the life cycle of this devices can reach more than 15 years.

Capacitor banks are role devices in this project. In consequence all their limitations and advantages will be considered in the solution for the Skagerak network.

2.3 Regulations and Technological Challenges

The application of capacitor banks in the electric system must comply with certain technical requirements. This is done in order to maintain the reliability of the electric supply and to standardize operation methods. Standards, guidelines and regulations are established by state organs and international organizations like: Institute of Electrical and Electronic Engineers (IEEE, [25], [24]), International Electrotechnic Comitee (IEC, [2]). In Norway, Statnett adapts these regulations. Nordpool. CENELEC

Maximum size

The maximum capacitor bank size is influenced by the following factors: a) Change in system voltage upon capacitor bank switching and b) Switching continuous current limitations.

If a capacitor bank is connected to the grid, the fundamental system voltage increases. If the capacitor bank is disconnected, this voltage decreases. In order to have a minimal effect upon customer loads, this voltage change is often limited to a value in the range of 2 % to 3 %. This voltage percent change can be estimated by next equation [25, p. 10].

$$V\% = \left(\frac{Q_C}{S_{sc}}\right) \times 100 \tag{2.27}$$

where

$V\%$ is the voltage change as a percentage of the fundamental frequency rms system voltage
Q_C is the Mvar size of the capacitor bank
S_{sc} is the available three-phase short-circuit MVA at the capacitor bank location

Switchgears are used to disconnect and connect the capacitor banks. As these and other devices used in the installation have to be run at rated conditions, this could be an economic factor that limits the power of the capacitor bank. The rating is usually determined by multiplying the nominal capacitor current by 1.25 for ungrounded capacitor banks and by 1.35 for grounded-wye capacitor banks.

Minimum size

The practical minimum capacitor bank size may be influenced by the following factors [25, p. 11]:

- The cost of the required switchgear and protection.
- Fuse performance and/or coordination
- The easily available ratings of capacitor units.
- The type of capacitor bank used: externally fused, internally fused, fuseless, etc.
- Capacitor bank unbalance considerations.

The principal concerns when installing a small capacitor bank are the proper performance of the proposed capacitor bank (including the protection) and the cost of the installation. Under some circumstances, the cost of the installation may be reduced by installing the capacitor on a lower voltage bus in the same substation [25, p. 11].

Switching Transients

Switching CBs can be used in order to adapt to the variable demand and supply of reactive power. They are switched manually (as in Skagerak Nett, K. Rydland, personal communication, May 15, 2013) or automatically in a hourly basis. There is a set of fixed capacitor banks connected permanently and a set of switching CBs that are connected during high reactive power demand (to supply part of it, see figure 2.2). The automatic CBs are usually controlled in regards of the voltage, current, reactive power, period and season variations. The methods to minimize and control transients are pre-insertion of resistors and reactors, synchronous closing and surge arresters.

Switching of CBs creates switching transients on the electric network. During connection the CB is energized and at disconnection it is de-energized. Both processes require to be handled to avoid damaging the CB and the electric network. Concern should be directed towards energizing a isolated CB, phase-to-phase insulation (regarding transformers and equipment that hold the same transient), back-to-back CBs (connected in parallel), prestrike and inrush current, outrush current and restrike [25].

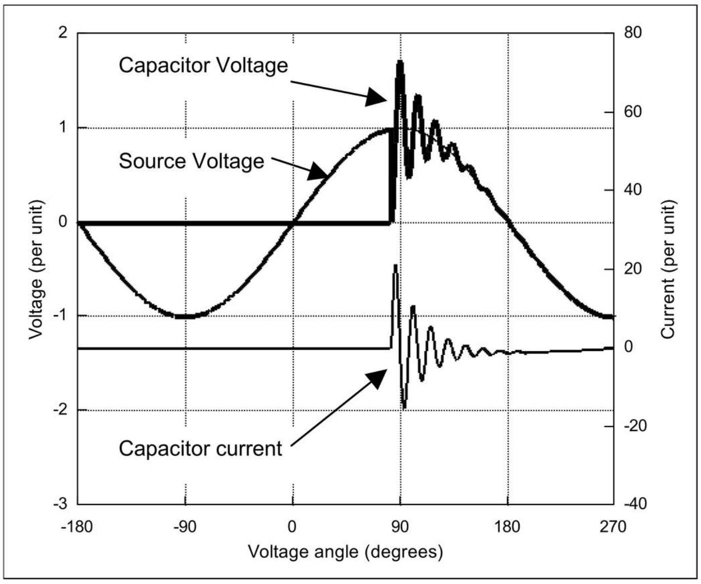

Figure 2.4: Voltage transient switching on a CB [25]

There are three types of switchgears. Circuit breakers allow switching of the CB on a frequent basis and provide short-circuit interruption for faults inside the CB. Circuit switchers do not have as much interruption capabilities as circuit breakers. The previous two switches can be equipped with reactors or be controlled by synchronous closing to reduce transients. Vacuum switches are used for medium and high voltage CBs. Oil switches are mostly used in the distribution network. Switches are classified into classes regarding the restrike performance. “The selection of a particular type of switchgear will be influenced by protection philosophy, short-circuit and transient current capability of the available devices, frequency of operation, effectiveness of transient reduction technique, reliability, and cost” [25]. .

Harmonics

Harmonic distortion of the electric system are caused by the use of electronic devices in industries, distributed resources and households such as converters, rectifiers or transformers. This can affect the performance of CBs, extra heating, dielectric stress and even cause damages if some of the limitations are not satisfied (2.2). Harmonics are not produced by CB but they can amplify their magnitudes which affect the system and the customers. Although the CBs can be overrated to hold harmonics, the phenomenon of resonance is still present [25]. Nowadays this is real issue that the utility companies have to deal with (K. Rydland, personal communication, May 15, 2013). The main harmonics that cause problems are the 3rd-9th odd ones (which correspond to 150-450Hz frequencies). Solutions to this problem are: ungrounding grounded-wye capacitors, changing capacitor bank sizes and/or locations, adding a reactor to an existing capacitor bank, adding a filter capacitor and, controlling the capacitor switching scheme to avoid resonance [25]. in addition, using shielded cables and controlling grounds properly [21].

The harmonic at which resonance may occur is calculated with next formula [21].

$$h = \left(\frac{S_{sc}}{Q_c}\right)^{1/2} \tag{2.28}$$

where S_{sc} is the short-circuit power of system at point of application and Q_c is the power of the CB. From equation (2.28), the resonant frequency can be calculated as

$$f_h = \frac{1}{2\pi}\left(\frac{1}{L_{sc} \cdot C}\right)^{1/2} \tag{2.29}$$

where L_{sc} is the inductance of the power system and C is the capacitance of the CB.

Chapter 3

Optimum Placement of Shunt Capacitors

It has been mentioned in Chapter 1 that the problem of optimum placement of capacitor banks is a complex problem. Its difficulty lies in the magnitude and complexity of the network and the nature of the constraints. In this chapter the Optimal Capacitor Problem (OCP) is stated and the methods to solve the problem are reviewed and the selected ones for this project are explained in detail.

3.1 The Optimal Capacitor Bank Problem

The general statement of the Optimal Capacitor Problem (OCP) has been defined in 1.4 and (1.1a), where the dependent and independent variables, the objective function and the constraints are already defined. Now each term of the statement will be defined in order to formally state the problem that is going to be solved.

3.1.1 Definitions

Capacitor Bank (CB) Source of reactive power consisting of capacitors arranged in a balanced 3-phase device. They will be regarded as loads with losses injecting reactive power. They can produce other constraints related for example to their size or the voltage fluctuation of the bus.

Power of a CB It is the reactive power that a CB can inject in the network at rated conditions.

Bus It is a connection point of the power lines, loads, power sources and CB. There are 3 types: Slack bus, PQ bus and PV bus (see 1.4).

Available bus It is a bus that can host a CB.

Capacitor Bank Configuration (CBC) It is a vector of powers of CBs with a component for each available bus. The CBC is the set of independent variables to the OCP. It is denoted as $\mathbf{C} = (C_1, \ldots, C_n)$, where n is the number of available buses. A capacitor with zero power is regarded as a non existing CBC.

CBC solution Is a CBC that satisfies the equations and inequalities of the OCP. There exist at least one solution which is the CBC with all the capacitors with zero power.

Solution space of the OCP The whole set of CBC solutions. It can be called also permissible region.

Optimal CBC solution It is a solution to the OCP, i.e., it is a CBC solution that minimizes the objective function.

Near optimal CBC solution It is the CBC solution that gives the minimum of the objective function from a given set of solutions. However, the term optimal solution will be used indistinctly for near optimal solutions, unless it is explicitly stated.

3.1.2 Constraints

The inherent constraints to the network are the power flow equations (2.16). Because with these equations the voltages magnitudes and phases are determined and afterwards the flow through the lines can be calculated. The power flow problem can be solved with a power system software like Power System Simulator for Engineering (PSS/E).

Operational constraints

In a real network there are magnitudes that have to be kept within some limits. The following is a list of the constraints (sorted by importance) that are commonly applied [32] and that will be used in this project. These three kinds of constraints are inequality constraints.

1. The voltage variation allowed for switching on and off the CBs is ±3%. This allows to switch on and off the CBs.
2. Maximum power of each CB, C_i^M, is half of the power of the transformer.
3. Minimum power of each CB, C_i^m, for economic reasons.
4. Power factor at each load bus have to be kept greater or equal to 0.95[1].

The reasons of these constraints are explained in Chapter 4. The constraints in the power of CB can be considered as only one. The total number of inequality constraints is

$$m + ml + 2n \tag{3.1}$$

where m is the number of buses, ml is the number of load buses and n is the number of available buses.

There are also other constraints that can be applied. These are related to other versions of the OCP.

[1]Low power factor at light load or high power factor (0.9) at high load are conditions [25, p. 21] that make this constraint to become less important (T. Eriksen, personal communication, May 15 2013)

1. Permitted voltages within an interval centred at 1 p.u.
2. Limits to voltage harmonic distortion [32].
3. Establish a minimum or maximum number of CBs to be installed in the whole network.
4. Maximum of total reactive power supplied by CBs in the network.
5. Establish a maximum or minimum budget for some of the following aspects: the whole project, the investments in CBs, costs of losses and monetary savings, economic rate of return and net present value.
6. Any kind of constraint in the power flows of the power lines.
7. Maximum total losses in the CBs.
8. Solve OCP and establish a set of fixed CB and a set of switching CB.
9. Forbidden capacities to avoid resonance and harmonic resonance 2.3.
10. Finite set of available CB powers.
11. Constraints relating the CB sizes of several available buses grouped by area or voltage level.

3.1.3 Objective function

As has been mentioned in Chapter 2, the installation of CBs in the network can contribute to reduce costs of operation and improve several aspects of the network. Although it is *per se* interesting to implement them on the network, they have associated costs that can make the project not worth the investment, a correct cost-savings outcome have to be performed. The criteria that is applied in the project is that the savings achieved by the project are greater than the 100 % [2]of investment costs. The costs of the whole project are expressed in the objective function. The objective function is the core of the problem, its definition determine the optimal solutions. have to be regarded always to the objective function. If the objective function changes, then the optimal solution will be no longer the same.

The objective function is the function that shall be optimized[3]. It includes the following parts: electric network active losses, reactive power costs, CBs investment and maintenance costs. So the objective function can be sketched as

$$\text{Total costs} = \text{Investment} + \text{Future Costs}^{4} \tag{3.2}$$

All these terms are transformed into monetary values. So the optimal solution is the one that minimizes the economic costs of operation in the electric network. These costs have to be summed over the desired timespan, which can be from one year to the life cycle of the CB.

Active power losses or conduction losses are caused by the resistivity of electric lines. The highest is the current, the largest are these losses (see 2.2.1). The costs associated with these losses can be

[2]However other approaches to the objective of the project can use different percentages.

[3]Some other approaches use multi-objective functions [13]

[4]Other objective functions could be used like for example: Total savings = Costs without investment - (Investment(CBC) + Future costs with investment(CBC)), with the goal of maximizing it. However this does not modify the optimum CBC because the costs without investment are a constant value.

calculated with the market price of kWh or with the cost of production of kWh. If the power balance of the issued electric network is negative, meaning to say, that the network absorb more energy than that is produced, then the price of kWh is used. In the other case, the cost of production is the right value. It can be assumed that the losses increase by a certain per unity value each year (p_L). If i is the discount rate, the present value of the losses of year t is

$$CP_L^t(t, \mathbf{C}) = C_k \cdot P_L(\mathbf{C}) \cdot \frac{(1+p_L)^t}{(1+i)^t} = C_k \cdot P_L(\mathbf{C}) \tag{3.3}$$

where P_L are the power losses of the first year and C_k is the cost per kilowatt-hour. It should be noted that P_L depends on the electric network characteristics and the CBC. They can be calculated with the difference of equations (2.11) and (2.12) for every line, once the power flow is solved, or by using the functionalities of the power system software. The total losses during the whole time span are expressed as the sum of losses of each year:

$$CP_L(T, \mathbf{C}) = C_k \cdot P_L(\mathbf{C}) \cdot \sum_{t=0}^{T} \frac{(1+p_L)^t}{(1+i)^t} = C_k \cdot P_L(\mathbf{C}) \cdot f_L \tag{3.4}$$

where the sum is denoted by f_L.

Reactive power billing charges are computed as follows in accordance to section 2.2.1. If the reactive power flow in the interconnection bus is larger than 20 Mvar in absolute value (because it can flow inwards or outwards), then a cost Q_k is charged per each Mvar. This can be expressed with the next formula.

$$cq_B(\mathbf{C}) = Q_k \cdot 5 \cdot \left\lfloor \left| \frac{Q_E(\mathbf{C})}{5} \right| \right\rfloor \qquad \text{(NOK)} \tag{3.5}$$

where Q_E is the exchanged reactive power in Mvar.

The costs of reactive power along the whole period can be computed with equation (3.6).

$$CQ(T, \mathbf{C}) = Q_k \cdot 5 \cdot \left\lfloor \left| \frac{Q_E(\mathbf{C})}{5} \right| \right\rfloor \cdot \sum_{t=0}^{T} \frac{(1+q_L)^t}{(1+i)^t} = Q_k \cdot 5 \cdot \left\lfloor \left| \frac{Q_E(\mathbf{C})}{5} \right| \right\rfloor \cdot f_Q \tag{3.6}$$

where q_L is the yearly increment in the cost of reactive power and the sum is denoted by f_Q.

Capacitor banks investment have to be included in the cost function. Otherwise, the optimum CBC would be simply the one that supplies the total reactive power consumed by the network. In this way, the active losses in lines would be minimized. However this solution is not easy to find and it may not exist as an excess of reactive power supply can infringe the voltage limits of a bus. Investment cost will be denoted by $CI(\mathbf{C})$ and it is simply the sum of the cost of each CB, that depends on its size and quality, the associated equipment (switch gear) and the installation adaptation.

Capacitor banks costs are related to maintenance and losses. These depends on the type of capacitor banks. One way of accounting this costs is to assign a yearly fixed cost to each capacitor. The total cost in maintenance is designed by $CM(\mathbf{C}, T)$ and it is the sum of maintenance of each existing CB in the CBC. The total maintenance costs in the whole period are

$$CM(T, \mathbf{C}) = M_k \sum_{t=0}^{T} \frac{(1+m_k)^t}{(1+i)^t} = M_k \cdot f_M \tag{3.7}$$

where m_k is the yearly increment in the costs of maintenance and f_M denotes the sum.

Genetic algorithms use the objective function to evaluate the fitness of the CBC. To evaluate if a CBC is in fact a solution satisfying all the constraints, another factor is added to the objective function that here is called constraints cost or penalization function, $CC(\mathbf{C})$[5].

The span of time at which the losses are evaluated is also a important parameter. If the time is long, a large initial investment can be better than a low investment case (see fig. 3.1)

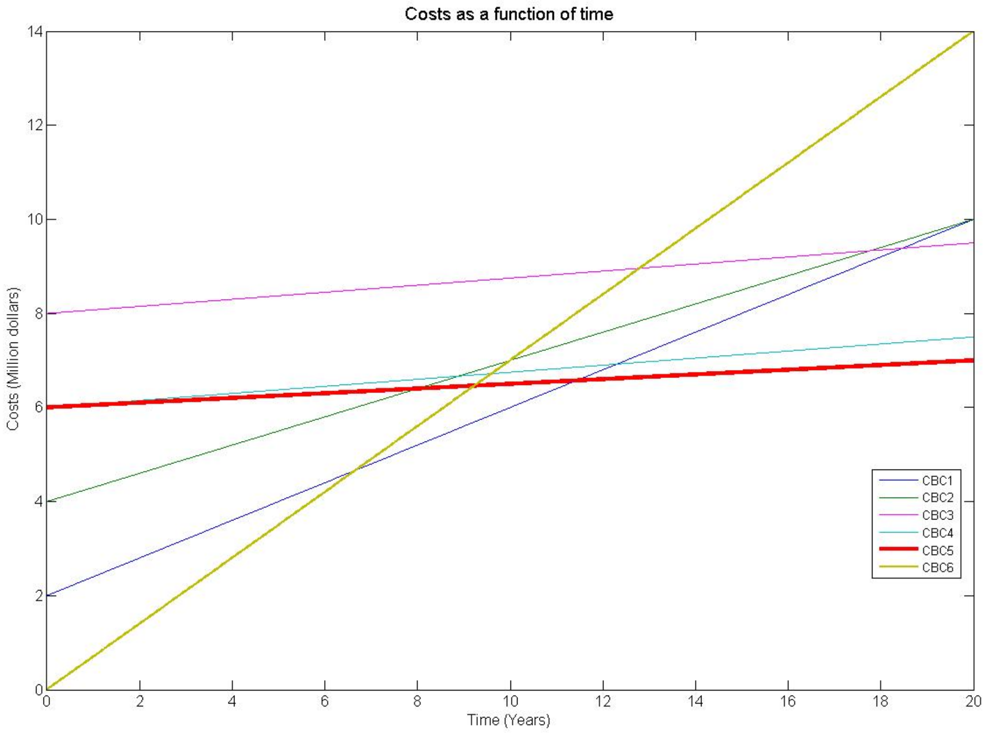

Figure 3.1: Accumulated cost function associated to constraints. CBC5 has a high initial investment, but the accumulated costs at the end of the period are the lowest in comparison to the other CBC.

The objective function is the sum of the above costs

$$F(\mathbf{C}, T) = CP_L(\mathbf{C}, T) + CQ(\mathbf{C}, T) + CM(\mathbf{C}, T) + CI(\mathbf{C}) + CC(\mathbf{C}) \tag{3.8}$$

[5]It is explained in more detail in section 3.2.2

The OCP problem (1.1a) can now be stated as follows.

$$\min_{\mathbf{C}} \; F(\mathbf{V}, \mathbf{C}, T) \tag{3.9a}$$

Subject to

$$(P_i, Q_i)(\mathbf{V}, \mathbf{C}) = 0, \quad i = 1, \ldots, m \tag{3.9b}$$

$$|\Delta V_j(\mathbf{V}, \mathbf{C})| \leq 0.03, \quad j = 1, \ldots, m \tag{3.9c}$$

$$\cos\left(\arctan\left(\frac{Q_i}{P_i}\right)\right) \geq 0.95 \quad j = 1, \ldots, ml \tag{3.9d}$$

$$C_i^m \leq C_i \leq C_i^M \quad j = 1, \ldots, m \tag{3.9e}$$

where,

$\mathbf{V}(\mathbf{C}) = (V_1, ..., V_m)$ is the vector of bus voltages
$\mathbf{C} = (C_1, ..., C_n) \in \mathbb{R}^n$ is the CBC

The problem is continuous, not discrete.

3.1.4 Associated problems

The described OCP is just a specific case of optimization of reactive resources. The problem can be formulated in several other ways that comprise the following aspects

Localization

The capacitor banks have to be placed in a set of buses. Their sizes are already specified. The solution have to give the places where the CBs optimize a certain objective. A usual constraint to the problem is maximum number of CBs.

Size

The available buses are known and it has to be decided what reactive power has be to supplied at each bus. The powers of CBs are supposed to be positive. Otherwise, this is the same problem as OCP.

Realocation

Given a set of CBs, give the best buses where they are placed to optimize a certain objective. Constraints related to the problem are number of CB per available bus.

The OCP concerns both size and localization. And it can be constrained to a fixed number of capacitor banks.

3.2 Solution approaches

3.2.1 Brute-search algorithm

Brute-search algorithm can be used if the solution space is small enough. It consist on checking the whole set of solutions one by one. If $\left(0, C_i^M\right)$ is the allowed interval of power rating of CB number i, then the search space is

$$\left(0, C_1^M\right) \times \left(0, C_2^M\right) \times \cdots \left(0, C_k^M\right) \tag{3.10}$$

where k is the number of available buses. If k is 10 or larger, then this search space is so large that is computationally not feasible of being explored. Instead of that, discretizing each interval in less points can narrow the search space to an attainable size [6]. Even then, for 10 available buses and 10 steps for each of them, the search space becomes too large (10^{10}). The problem with this approach is that the real optimal solution may not be found. The algorithm can be written in pseudo-code as follows.

Data: Network
Result: Optimal CBC solution $min_{\mathbf{u}}$
$min_f = 10^{12}$;
`// Just a large value` $min_{\mathbf{u}} = 0$;
for ***u*** *in Search Space* **do**
  $f = f(\mathbf{u})$ `// Evaluate fitness of CBC ;`
  if $f < min_f$ **then**
    $min_{\mathbf{u}} = \mathbf{u}$;
    $min_f = f(\mathbf{u})$;
  else
  end
end

Algorithm 1: Brute-search algorithm

3.2.2 Genetic Algorithms

Genetic Algorithms (GAs) can be applied to several fields within power systems, for example, var planning, capacitor placement, unit commitment problem and loss minimization switching [35]. In [28, 29] it is shown "that genetic algorithms can have better results for capacitor placement compared with conventional linear programming and non-linear programming methods".

GAs are inspired by biological genetic processes. The basic idea is that solutions (or individuals) evolve producing new an better solutions. In the following exposition chromosome, individual and CBC will be used in the same sense. The three key concepts are the following [37].

Selection The best solutions of a given set (population) are selected in two processes: to give birth the offspring and to survive to next generation.

[6] For instance if $C_i^M = 10$ Mvar then the points to try are $0, 1, 2, \cdots, 10$ Mvar.

Recombination The population of individuals is combined with some deterministic or probabilistic rules to give birth to new solutions.

Mutation The set of solutions is slightly modified in order to introduce innovation and examine the whole solution space.

Some vocabulary is borrowed from biology. Population refers to a set of individuals or CBC solutions of a fixed size, that can also be called chromosomes, which are made up of genes. The population is improved generation after generation. The algorithm has the following steps.

Data: Network
Result: Near Optimal CBC solution $min_{\mathbf{u}}$
Create a random initial population of p individuals (CBC) ;
Evaluate the *fitness* of each individual ;
for *i from 1 to* Numberofgenerations **do**
    Select best individuals from actual population for reproduction;
    Reproduce selected individuals and create offspring through *recombination* and *mutation*;
    Select best individuals that survive in the new generation;
    Evaluate the fitness of each individual ;
end
Return individual with best fitness;

Algorithm 2: Pseudo-code of a genetic algorithm

Three sets of individuals are used in the algorithm: population, breeding pool and offspring. The population is the set of individuals in the actual generation; the breeding pool contains the individuals that create the offspring.

The algorithm uses certain operators in each of these steps. These operators can be defined in several ways, which establish various types of genetic algorithms. The choice of the functions may depend on the problem that is being solved and they can have adjustable parameters, that are modified depending on the performance of the algorithm.

Creator

The *creator* operator has to define the initial population in a random uniform way, so that the wide variety of solutions is explored and the population is not biased towards a certain type of solutions. The initial generation of solutions just have to satisfy the constraints of the problem, there is no need to be good solutions in terms of optimization. If there is a CBC that do not satisfy the constraints, it is not discarded initially. Instead of that, it is ranked and the best of them can contribute to offspring. The cost function, $CC(\mathbf{C})$, ensures that the population evolves towards CBC solutions. The function assigns large costs to those ones that infringe the constraints, as is depicted in figures 3.2 and 3.3.

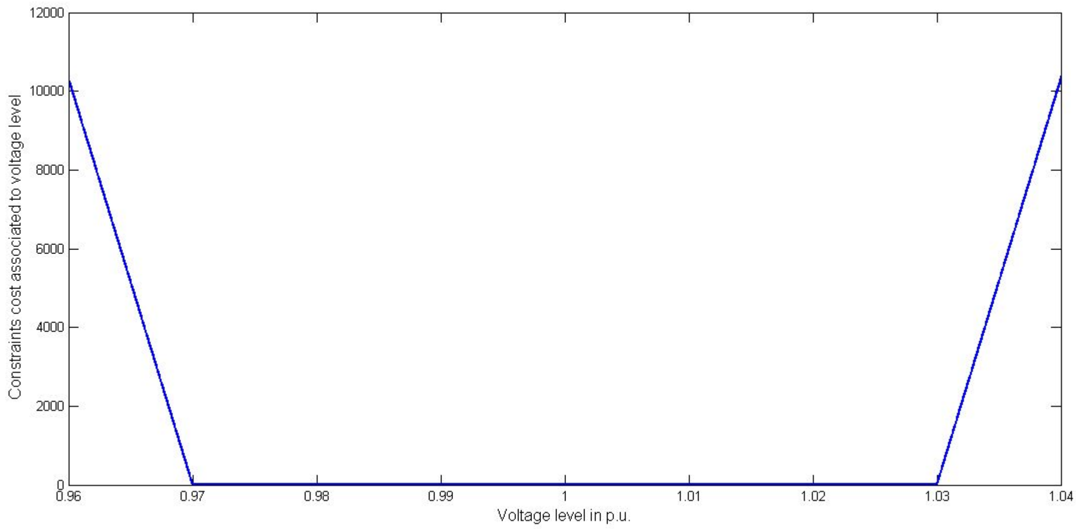

Figure 3.2: Cost function associated to voltage level constraint. Here 1 p.u. represents the nominal voltage of the bus of the original network.

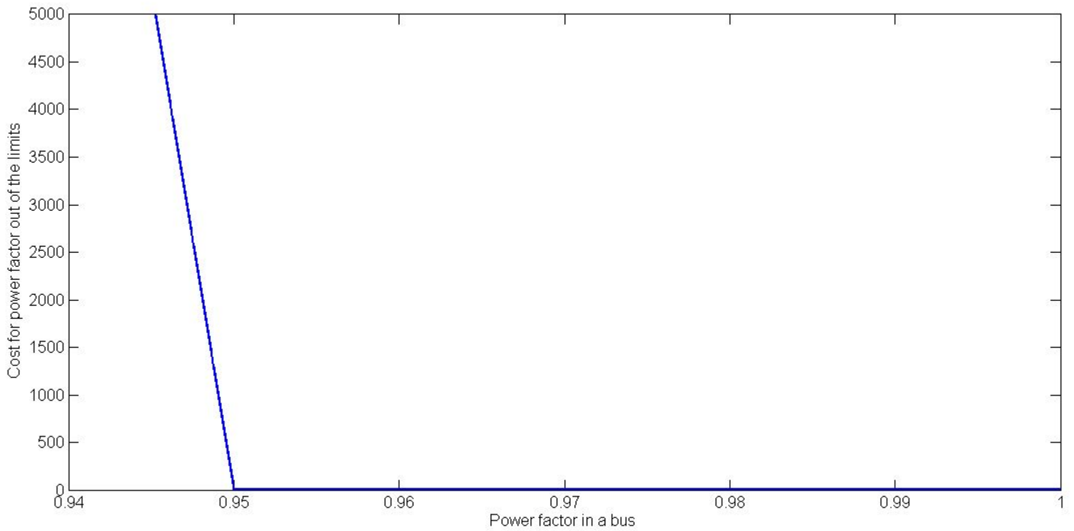

Figure 3.3: Cost function associated to power factor constraint.

Fitness

The fitness of a solution rates how good the solution is and allows to rank them respect the other solutions in order to make the selection. The fitness function is usually the Optimization Function (OF) of the problem. But also, it is complemented with other functions that rate the fitness of the solution to constraints (CC). The purpose of the constraints costs (or penalization function) is to discard CBCs that are no solutions by assigning them a high cost. In the final solution, the cost associated to constraints have to be zero, which means that this CBC is a solution. Penalization methods are used in constrained optimization problems [10]. They allow to transform a constrained optimizations problem into an unconstrained one. In fact, the problem that will be solved consist only of equations (3.9a) and (3.9b) (the constraints are included in the penalty function).

Selection

The *selection* of individuals is used to create the breeding pool, the set of parent matches that will give birth to offspring. the parents and the individuals that survive to next generation are also operators that depend on variable parameters that are chosen appropriately to each problem. There are two standard types of selection: stochastic tournament and roulette wheel [35]. A set of parent matches is created (which usually is the same size as the population). Each chromosomes can be selected more than once, giving birth to two individuals.

Stochastic tournament consists in selecting randomly two (or more) individuals from the population and choosing the one with best fitness. In this way, the best CBC have a higher expectancy of being selected, although low rate solutions can be selected which allows to preserve a wide genetic pool. The same is applicable to roulette wheel selection. It consists of selecting a chromosome with a probability proportionally to its relative fitness (3.11).

$$p_i = \frac{f_i}{\sum\limits_{i=1}^{p} f_i} \tag{3.11}$$

where p_i is the probability of selecting individual i and f_i is its fitness. The selection scheme is called roulette wheel because the parents can be thought as the sockets in the roulette with a thickness proportional to its relative fitness. In this way the chromosomes with best fitness are selected for reproduction with a higher probability than those with low fitness, and in average the percentage of new individuals that spring from a CBC is proportional to its fitness.

Recombination

The *recombination* function (or operator) takes individuals from the elite population section and creates new "breeding pool" [37, p. 39]. The recombination function can be created in several ways, but the idea is the same in all of them: take chromosomes from the parents and recombine them to create a mixed chromosome. The children is expected to have better chromosomes. This operation is also called crossover. The crossover probability (CXPB) is the probability that a recombination is performed and passed to next generation. A crossover probability of 1 means that the whole offspring is made from recombination, while a value of zero means that the offspring is made of copies of the previous generation. The crossover function can be defined as one-point crossover, two-point crossover, uniform (get randomly a gene from one of the parents), line recombination (linear combination of the genes of the parents), and volume crossover (multilinear combination of the genes of the parents) [37, p. 40]. One-point crossover consists on selecting a position of the chromosome randomly and crossing both sides of each parent to create two children (Table 3.2). Two-point crossover consist in selecting two points and exchanging their middle segments.

Table 3.1: Table showing one-point crossover. Each individual is represented as a string of bits. The bar '|' is a picked up random position for each crossover.

Parent A	11101|10101100
Parent B	10010|10000100
Child AB	11101|10000100
Child BA	10010|10101100

Table 3.2: Table showing two-point crossover. Each individual is represented as a string of bits. The bars '|' are picked up random positions for each crossover.

Parent A	11|101101|01100
Parent B	10|010100|00100
Child AB	11|010100|01100
Child BA	10|101101|00100

The *mutation* operator consist on introducing small variations to the chromosomes of each offspring chromosome. As the chromosomes are coded in binary strings, the mutation consists in changing the bits on random positions with a predefined probability. This allows the population to have a large diversity along the search space. In this way the algorithm does not converge to a local solution, which is not the objective, the algorithm has to find a global optimum. Diversity is needed to find that global optimum. The probability of mutation is controlled by the predefined mutation probability (MTPB). If this parameter is too high then the algorithm can take too much time to converge, and if it is too low the population can be biased towards a non global solution.

After mutation, selection takes place. The new generation has been created but it has to be compared with its parent generation. The best CBCs are then selected to survive. One way to do that is elitism selection: the best solution of the two previous generations is preserved together with the offspring generation.

Randomness is an important point of genetic algorithms. As it has been explained, randomness is used in: the first generation, the parents selection, the crossover point and the mutation operator. While this makes the algorithm to converge to different near-optimal solutions at each run, it is the essential process by which the algorithm does not converge to fast to a solution. It is important that the algorithm does not converge too fast, otherwise the whole solution space would be poorly explored. Randomness can modify the response of an genetic algorithm. Each genetic algorithm is caracterized by its operators and parameters: population size, number of generations, codification, crossover probability, mutation probability.

GAs variants

There exist many versions of genetic algorithms, each of which can work better in certain cases. Three versions are described below. The simple genetic algorithm with elitist selection (ESGA), follows the procedures described in this section with the addition that the best solution of each generation survives by default to next generation. The $\mu + \lambda-$ Genetic Algorithm (MPLGA) generates λ individuals as offspring and selects μ individuals from population and offspring altogether. While the $\mu, \lambda-$ Genetic Algorithm (CMLGA) selects μ individuals just from offspring (of size λ)

to survive to next generation.

Data: Network
Result: Near Optimal CBC solution $min_{\mathbf{u}}$
Create a random initial population of p individuals (CBC) ;
Evaluate the fitness of each individual ;
for *i from 1 to* Numberofgenerations **do**
  Select better individuals from actual generation for reproduction;
  Reproduce selected individuals and create next generation through *recombination* and *mutation*;
  Select best individuals that survive in the new generation;
  Evaluate the fitness of each individual ;
  Survival selection to next generation;
end
Return individual with best fitness;

Algorithm 3: Pseudo-code of a genetic algorithm

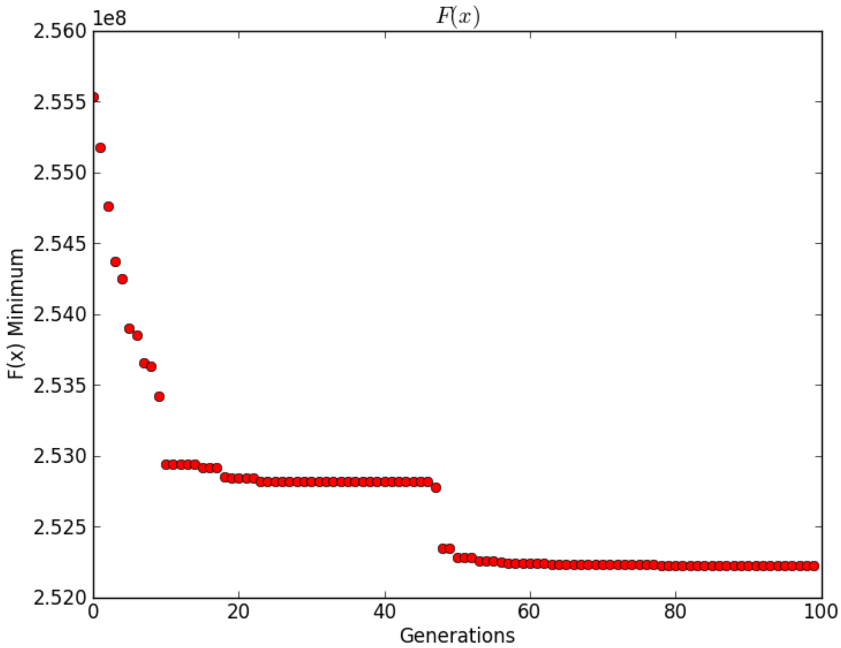

Figure 3.4: Execution of the GA for the Telemark network. At each generation the best solution is plotted. Parameters: POP=200, CXPB=0.75, MTPB=0.35, NGEN=100.

3.2.3 Comparison of Methods

GAs has no need to know how is the problem or how is the network. This could be an advantage although more knowledge of the network could help to establish a specialized algorithm for each network. In general, GAs can work for certain applications but not for others.

Brute search is intended to explore the whole search space. However, it is far from doing this, as the search space is quite large. Brute search can only take a overview of the solution space because it only explores an uniform mesh of CBCs. The exploration is not driven towards the best solutions.

However the overview is good in the sense that can help to identify the permissible region. In terms of optimality it is not completely sure that the brute search finds a optimal solution.

GAs directs the search towards best solutions. It also intends to find a global optimal. The fact that it finds the same solution at several runs indicates in part that a optimal solution is found. However heuristic methods can not completely assure that the global optimum has been found. GAs can be tested with known functions.

GAs are controlled by parameters. One can run the algorithm and modify this parameters if the results were not satisfactory. This is not possible with the brute search algorithm.

GAs can converge or not converge. An adjustment of parameters have to be done in order to get good results or better than the ones already found. Even when convergence is achieved, the given solution could be just a local minimum (Figure 1.6). To discern these cases, multiple runs of the GA can be carried on using different parameters.

3.3 Optimization Criterion

The impossibility to determine the optimal solution to the Optimal Capacitor Problem (OCP) makes necessary to establish another optimization criteria. The chosen optimal solution may not be the solution of OCP. Then a different criteria to minimization can be chosen to get a quite enough solution.

Termination conditions of Genetic Algorithms (GAs) are diverse and are closely related to the optimization criterion. For instance some of the following can be applied in the same algorithm.

- Maximum number of generations reached (used for example in [32]).
- Convergence of the solution (the solution is the same for a certain amount of generations).
- No significant improvement of the objective function for a certain amount of generations.
- Pre-established lower bound value of the function reached.
- Computation running time reached.

Some optimization criteria that can justify the optimality of the chosen solution are:

- The values reach a certain amount or fall within a certain range. For instance, the values reach a known lower bound.
- The total cost of the solution achieve a certain percentage of the original cost or it is below of a certain amount.
- Several runs getting the same solution.
- Several runs getting the similar solution. The best of them is the optimal one.
- Several runs that get to the same value of the objective function.
- Several methods get to the same result.

- The search space has been fully explored within the algorithm.

Justification of the optimization criteria is the key as a known minimum can not be achieved. The criteria will determine what is the solution. The criteria is no longer the minimum value, but a closer one. In this sense, the solutions can be regarded as near-optimal solutions. Several solutions can be post analysed and other criterias can be applied.

GAs can be modified with several parameters and if the same solutions are found, then is quite fair to say the solution is the optimum one.

GAs can not guarantee 100% that one gets the optimal solution because they are stochastic and heuristic algorithms. Theoretic results are also based in statistics. First proposition in [39] guarantees convergence to the optimum solution with probability 1, but the conditions must be satisfied. Nothing can be stated about the speed of convergence.

GAs are programmed procedures that cannot assure the optimality of the solution. Thus, to answer if a solution is globally optimal, post analyses can be realised. For instance, showing a lower bound for the objective function.

Chapter 4

Optimum Solutions For The Skagerak Transmission Network

The network under study is presented within its particularities and constraints. The resulting problem is stated and the results from the algorithms are given.

4.1 The Skagerak Network Topology

The Skagerak Nett network is composed by two networks, one in Telemark and one in Vestfold. The two networks are separated for analysis purposes, though they are interconnected in one transformer station (T. Eriksen, personal communication, May 15, 2013). Both are transmission networks that have voltage levels that ranges from 56 kV to 300 kV. However the lines of 300 kV are controlled by the Transmission System Operator (TSO). These lines are not included in the analysis as the optimization is restricted to Skagerak Nett Network. At the interconnection stations with the TSO the active and reactive power exchange is measured and traded.

The 56/66 kV power stations connect to the customers in the low voltage level through 56/11 kV or 56/22 kV transformers. The networks of 11/22 kV are distribution networks, so they are radial networks. These distribution networks will not be included in the analysis. The problem can be solved for them with a dynamic programming approach mentioned in section [20]. However to make clear what is the best place to install Capacitor Bank (CB), a global analysis of the network should be carried [19]. The analysis that will be made is just focused in the transmission network. Which is also important as there is the need, in this network, sorted by importance, to reduce losses, reduce reactive power bill and release system capacity (T. Eriksen, personal communication, May 15, 2013). It is then, not a useless approach to do the analysis separating transmission and distribution networks. Nevertheless, the reactive power losses in the distribution network can not be compensated completely by the Capacitor Bank Configuration (CBC) installed in the transmission network because the reactive power does not travel long distances [40].

4.1.1 Telemark Network

The Telemark network is composed by 88 buses, 13 of them are available buses. It has 3 separated networks, which can be interconnected in case of necessity or for maintenance tasks. The main network has 77 buses, which is the only one with available buses. Two buses of the network are not included as they are part of an industrial complex directly connected to 300 kV lines. The significant voltage levels are 56 kV, 125 kV and 132 kV. There are already stations with capacitor banks with powers from 4.5 to 6.5 Mvar. Only one of the CBs is disconnected during the summer season. Next table shows a summary of characteristics of Telemark network.

Table 4.1: Telemark network characteristics

	Number
Buses	88
300 kV buses	3
132 kV buses	63
125 kV buses	1
56 kV buses	21
Sub networks	3
Generators	33
Loads	54
Transformers	9
Available buses	13
Available buses at 132 kV level	13
Available buses with CBs	10
Branches	101

.

Table 4.2: Telemark power characteristics from 8AM to 9AM. Data retrieved from PSS/E.

	Active Power (MW)	Reactive Power (MVAr)
Winter total power generated	1531.8	242.7
Winter total load	1511.0	189.2
Winter total losses	20.8	53.5
Winter total power of CBs	-	71.9
Summer total power generated	846.9	165.5
Summer total load	813.8	125.3
Summer total losses	33.1	40.2
Summer total CBs power	-	59.9

The winter season is much more power demanding. The generated active power in the summer is only 55 % of the generated active power in winter. This is in accordance with a reduction of 46 % of the loading. Similar figures hold for the reactive power. However, it is worth noting that the reactive power supplied by CBs is nearly the same in both seasons, there is only a difference of 6 Mvar.

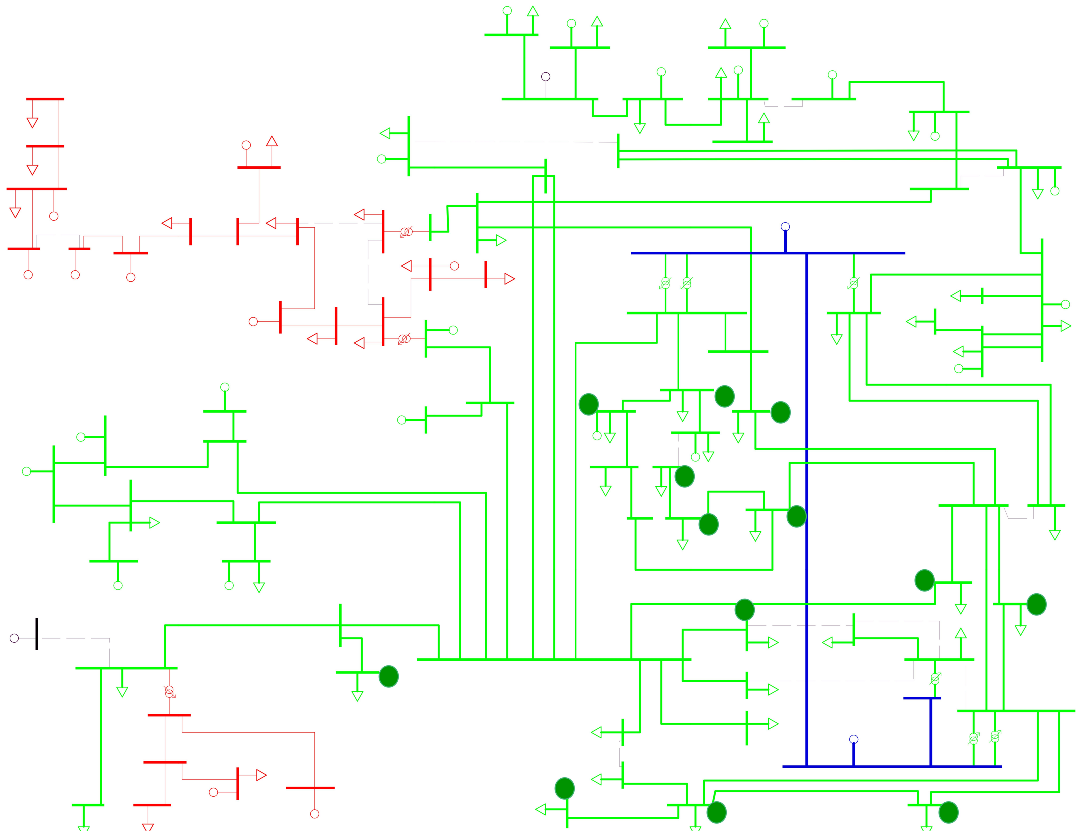

Figure 4.1: Telemark transmission network with voltage levels 300 kV (blue), 125-132 kV (green) and 56 kV (red). Available buses marked with green circle.

4.1.2 Vestfold Network

In the Vestfold network there are 63 buses which are all interconnected in the same subnetwork. There are much more CB installed in Vestfold, 28 (in 28 stations), with powers from 2.8 Mvar to 21.6 Mvar. There are 38 available buses in Vestfold. Most of them are disconnected in the summer season; two of them are partially disconnected as they actually are composed of two CB modules. The voltage levels in Vestfold are 66 kV, 130 kV and 300 kV. Table 4.3 shows some of the characteristics of the Vestfold network.

In terms of generated power and power loads, the Vestfold network is smaller than the Telemark network. However, the number of available buses is much higher in the Vestfold Network (VN) and the power of CBs already installed doubles the one in Telemark Network (TN).

4.2 Assumptions

The power figures presented in section 4.1 are based in the models of Skagerak Nett of the winter season, which is the significant one when it comes to analyse the network (T. Eriksen, personal communication, May 15, 2013). The loads represent the maximum active power demand period, which normally occurs from 8AM to 9AM.

Table 4.3: Vestfold transmission network characteristics.

	Number
Buses	63
130 kV buses	44
66 kV buses	15
300 kV buses	4
Sub networks	1
Generators	7
Loads	44
Transformers	7
Available buses	38
CB at 66 kV level	3
CB in 130 kV level	26
Available buses without CBs	9
Available buses at 66 kV level	9
Branches	73

Table 4.4: Vestfold power characteristics (8AM to 9AM). Data retrieved from PSS/E.

	Active Power (MW)	Reactive Power (MVAr)
Winter total power generated	1003.8	184.5
Winter total load	990.9	114.4
Winter total losses	12.9	70.1
Winter total power of CBs	-	203.27
Summer total power generated	464.1	-28.8
Summer total load	461.2	31.5
Summer total losses	2.9	Check purchased reactive power
Summer total CBs power	-	122.3

PSS/E is the software that contains the model of the network. Apart from the loads, the significant figures of the network are: line impedances, power limits of generators, transformer impedances and transformer steps. The model has some in-build assumptions or simplifications that are listed below.

1. The network is balanced. Which means that all the 3 phases transport the same power. In fact, the PSS/E model is a one-line model.

2. The loads are linear and does not add harmonics to the network [1].

3. Losses of 55/22(11) kV transformers are ignored. These transformers are not included in the model.

4. The transformer are allowed to do steps.

5. As a general rule, the power of a CB is half of the transformer power (T. Eriksen, personal communication, May 15 2013).

6. Capacitor bank losses are not significant and thus are not included in the model.

The actual project of installing a CB requires a detailed study of the transformer station and the corresponding transformer(s) (K. Rydland, personal communication, May 15 2013). Each transformer station has particularities regarding:

- Available required space for the new capacitor bank

- Available required space for extension of existing switchgear

- Suitability of existing switchgear with regards to easy extension e.g. spare cubicles, outdated equipment etc.

It will also include a harmonic study and as well a study of potential resonance problems with regards to the installed transformer(s). The result of the optimization approach adopted in this project will be a wide insight on the best placement of CBs. In this way, the inclusion or not of the previous assumptions are not significant for the final result.

The magnitudes involved in the problem are of the order of MW and Mvar. There is no point then in dealing with kW and kvar. The cost of a kW along a year is 1050 NOK ($0.35 \cdot 3000$, Table 4.5), while the cost of a MW is 1.050.000 NOK.

[1] However there are some approaches that include harmonics [32]

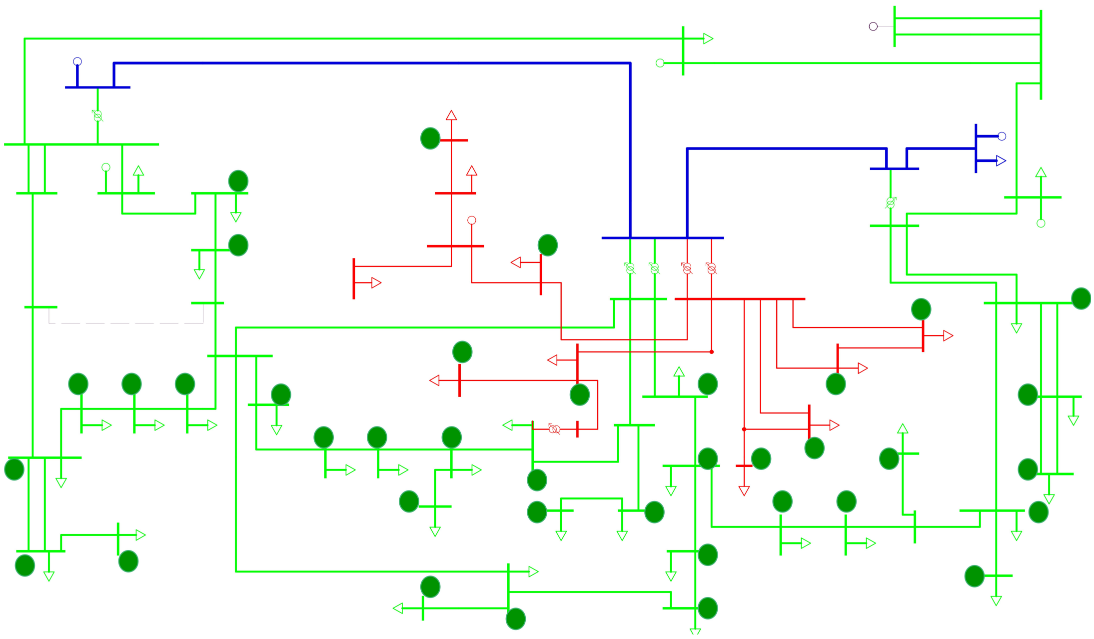

Figure 4.2: Vestfold transmission network with voltage levels 300 kV (blue), 130 kV (green) and 66 kV (red). Available buses marked with green circle.

4.3 Methodology

The algorithms have been implemented with Python. They can be found in the appendices. Python scripts execute the optimization algorithm and obtain the data from PSS/E. The data is only needed in order to evaluate the fitness of each solution; the rest of the script is the Genetic Algorithm (GA). An overview of the evaluation of a CBC is shown in next steps:

1. Convert the representation of the CBC in the algorithm to capacitor powers of the CBC.
2. Modify the original loads data of PSS/E according to the CBC (each CB is a load of negative reactive power).
3. Evaluate the power flow of the modified network using the flow tool from PSS/E.
4. Retrieve active power losses, reactive power exchange, voltage levels and power factors.
5. Use the previous data to calculate the costs in currency and to check the constraints.
6. Return the fitness of the CBC including the constraints costs.

In the following there is a description of the data obtained from the PSS/E models.

Active power losses The resistance of power lines makes them to consume energy that is produced in power plants but it is not consumed by customers. These losses are in some way economically compensated within the revenue cap regulation with regards to the business profitability[2]. Nevertheless, it is the socio-economic gain of reduced losses that Skagerak prefers to compute. The costs of the losses are computed as the market price of energy. From the reference value that Skagerak Nett pick from Nordpool, the assigned cost to losses is 0.35 NOK/kWh. The power losses of the sub-network under consideration are calculated by PSS/E.

Reactive power exchange The reactive power exchange is measured in the transformers that connect the 300 kV lines with the Skagerak transmission network. There are 5 of these transformers at each Skagerak subnetwork, whose power transfer is retrieved from PSS/E. The reactive power transfer can be inwards or outwards the Skagerak network. The net transfer of the exchange points is then used to compute the charge as explained in section 3.5.

Voltage level The voltage levels are calculated each time that the power flow is solved (see 2.16). These values are returned in a list by PSS/E and used to check the constraint of 3 % variation in voltage (see 3.1.2).

Power factor The loads are changed when CBs are installed. The loads are retrieved from PSS/E in order to check if the power factor do not experiment a significant modification and that is greater than 0.95 (see 3.1.2)

PSS/E has to calculate a power flow for each CBC. As it is well known, the power flow problem can be solved with several numeric methods. In this case, the full Newton-Raphson method is used with tap adjustment enabled. The advantages of PSS/E are that the network is already implemented and the power flow problem is solved without the need of creating another program for it. The implemented solver of the power flow problem contains several options and parameters in order to work in an efficient way for any kind of network and situation [42]. In this way, the use of PSS/E transforms the objective function in a black-box[3] from which the input that produces the optimum output has to be found.

4.4 Network Data

The electric data of the network is provided by Skagerak Nett AS through their PSS/E model. Apart from this data there is the data associated with costs that is shown in table 4.5. The data defines the objective function (section 3.1.3).

Table 4.5: Costs data.

Concept	Cost
Active power losses	350 NOK/MWh [4]
CB maintenance	2000 NOK/(CB year)
Reactive power costs	30000 NOK/Mvar
Station adaptation	500000 NOK/CB
CB investment	$19672 \cdot P_{CB} + 58197$ NOK, if $P_{CB} > 0$ [5]

[2]Skagerak Nett, as a transmission network utility, is obliged to try to find best possible socio-economic network solutions. The revenue cap regulation, that all the network utilities in Norway has to act according to, is working in such a way that the network utility will in an economic way (pure business profitability) benefit from reduce losses, reduce maintenance costs and increase effectiveness in general.

[3]Many optimization problems are classified as black-box optimization.

In 3.1.2 the constraints used in the Optimal Capacitor Problem (OCP) have been listed. The constraints on maximum and minimum power and voltage variation are determined by the particular network. The step down transformers to distribution network that Skagerak Network have rated powers that limit the maximum power of the CBs. The minimum power of each CB is due to economic efficiency as the switchgear cost is the same for all the rated power below the minimum. The voltage variation of three percent is also determined by the Skagerak Network. These variations are respect the original voltage level of the Skagerak Network. The reason is that Skagerak Nett want to be able to switch on and off the CBs in a daily basis.

Based on the above constraints 3.1.2, the penalization functions for voltage levels, power factor and capacitor bank power range are defined in equations (4.2), (4.4) and (4.6) respectively. The 10^{10} is chosen to blow the costs for those CBC that does not satisfy the constraints. It can be chosen differently for each problem or each constraint function depending on the importance of it. For example, this factor has been squared in

$$pev_i(\mathbf{V}, \mathbf{V'}) = \begin{cases} |V_i - V_i^{'}| \cdot 10^{10} & \text{if } |V_i - V'_i| > 0.03, \\ 0 & \text{otherwise} \end{cases} \tag{4.1}$$

$$Pe_V(\mathbf{V}, \mathbf{V'}) = \sum_{i=1}^{n} pev_i(\mathbf{V}, \mathbf{V'}) \tag{4.2}$$

where,

$\mathbf{V} = (V_1, ..., V_m)$ are the voltage levels of the m buses of the original network and,

$\mathbf{V'} = (V_1^{'}, ..., V_m^{'})$ are the voltage levels of the m buses of the network with new CBs.

$$pepf_i(\mathbf{PF}, \mathbf{PF'}) = \begin{cases} |PF_i - PF_i^{'}| \cdot 10^{10} & \text{if } |PF_i - PF'_i| > 0.2 \text{ and } PF_i^{'} < 0.94, \\ 0 & \text{otherwise} \end{cases} \tag{4.3}$$

$$Pe_{PF}(\mathbf{PF}, \mathbf{PF'}) = \sum_{i=1}^{n} pev_i(\mathbf{PF}, \mathbf{PF'}) \tag{4.4}$$

where,

$\mathbf{PF} = (PF_1, ..., PF_{ml})$ are the power factors of the ml loads of the original network and,

$\mathbf{PF'} = (PF_1^{'}, ..., PF_{ml}^{'})$ are the power factors of the ml loads of the network with new CBs.

$$pec_i(\mathbf{C}) = \begin{cases} -C_i \cdot 10^{30} & \text{if } C_i < 0, \\ 0 & \text{if } C_i = 0, \\ C_i \cdot 10^{10} & \text{if } C_i \in (0, C_i^m/2)\ , \\ (C_i^m - C_i) \cdot 10^{20} & \text{if } C_i \in (C_i^m/2, C_i^m)\ , \\ 0 & \text{if } C_i \in (C_i^m, C_i^M)\ , \\ (C_i - C_i^M) \cdot 10^{20} & \text{if } C_i^M < C_i \end{cases} \tag{4.5}$$

$$Pe_C(\mathbf{C}) = \sum_{i=1}^{n} pe_i(\mathbf{C}) \tag{4.6}$$

where,

$\mathbf{C} = (C_1, ..., C_n)$ are the powers of the n CBs.

$$P_{NC}(\mathbf{C}, m_{CB}) = \begin{cases} 0 & \text{if } |\{C_i :\ C_i > 0\}| < m_{CB}, \\ 10^{20} & \text{otherwise} \end{cases} \tag{4.7}$$

These components define the global constraint function as

$$CC(\mathbf{C}, \mathbf{PF}, \mathbf{PF'}, \mathbf{V}, \mathbf{V'}) = Pe_V(\mathbf{V}, \mathbf{V'}) + Pe_{PF}(\mathbf{PF}, \mathbf{PF'}) + Pe_C(\mathbf{C}) + P_{NC}(\mathbf{C}, m_{CB}) \tag{4.8}$$

Economic assumptions

- The price of energy along the span of time is constant and is approximated to 350 NOK/MWh.
- The reactive power exchange is an approximation because the reactive power exchange is measured as mentioned in 3.1.3.
- The life span of the capacitors is 20 years (K. Rydland, personal communication, Mars 27, 2013).
- The energy[6] losses cost in a whole year are calculated bt multiplying the power losseby 3000 hours (K. Rydland, personal communication, May 10, 2013).
- The line power losses and reactive are incremented each year by 0.2 %.
- The discount rate for the period of 20 years is 4.5%.
- The costs of maintenance are incremented each year by 1%.

Table 4.6: Economic data.

Concept	
Hours per year	3000
CBs life span	20 years
Discount rate	0.045
Increment in losses per year	0.002
Increment in reactive power per year	0.002
Increment in maintenance per year	0.01

With these values the accumulated costs of 1 and 20 years without doing investments in CBs is shown in Table 4.7 and Table 4.8.

[6] Energy is the work done by a power during a certain amount of time

Table 4.7: Costs without CBs in Telemark

Concept	Cost 20 years (MNOK)	Cost 1 year (MNOK)
Active power losses	242.10	17.54
CBs maintenance	0	0
Reactive power costs	78.74	2.40
Station adaptation	0	0
CBs investment	0	0
Total costs	320.84	19.94

Table 4.8: Costs without CBs in Vestfold

Concept	Cost 20 years (MNOK)	Cost 1 year (MNOK)
Active power losses	130.54	9.45
CBs maintenance	0	0
Reactive power costs	78.74	3.31
Station adaptation	0	0
CBs investment	0	0
Total costs	209.29	12.76

The final expression of the objective function with the span of time substituted is shown in equation (4.9).

$$F(\mathbf{C}) = f_L \cdot 350 \cdot 3000 \cdot P_L(\mathbf{C}) + f_Q \cdot 30000 \cdot Q_{ex}(\mathbf{C}) + f_M \cdot 2000 \cdot CN_1(\mathbf{C}) + 500000 \cdot CN_2(\mathbf{C}) + I(\mathbf{C}) + CC(\mathbf{C}) \tag{4.9}$$

where,

$P_L(\mathbf{C})$ are the power losses in watts,

$Q_{ex}(\mathbf{C})$ is the reactive power exchange value for one year [7],

$CN_1(\mathbf{C})$ is the number of stations with CBs that have to be maintained,

$CN_2(\mathbf{C})$ is the number of switchgears,

$I(\mathbf{C})$ are the total investment costs of the CBC,

$CC(\mathbf{C})$ is the cost of constraints that is zero for each solution, and

$f_L = f_Q = 13.81$, $f_M = 14.75$ are described in section 3.1.3 which are the values that correspond to the use of the data in table 4.6.

[7]The reactive power is charged with the net exchange of both networks, Telemark and Vestfold. For this reason the total reactive exchange is computed jointly although the optimization is done separately.

4.5 Algorithms

4.5.1 Algorithm Implementations

Codification of CBC is strings of binary numbers. The length of the strings will determine the precision to which the power of capacitors will be determined. Too high length can make the algorithm spend too much time. The standard length of each string is 12 bits (although it can be modified to get other results). The amount of numbers that can be comprised in 12 bits is $2^{12} = 4096$. These numbers have to be transformed into the permissible ranges of each capacitor bank. For example, the number $100100100100_{(2)} = 2340_{(10)}$ is transformed into a power rating of a CB in the following way. Let 5 and 15 the minimum and maximum size of the CB for this station. The base number for transformation is $M = 4095_{(10)} = 111111111111_{(2)}$ (which is maximum with 12 bits).

$$2340_{(10)} \cdot \frac{15}{4095} = 8 \text{ Mvar} \tag{4.10}$$

In this case the assigned power to the gene 100100100100 will be 8 Mvar. For this case, each integer is separated from each other by power of 0.00366 Mvar ($1 \cdot 15/4095$). For the station with maximum available power this value is $76/4095 = 0.02$ Mvar. This values allow enough precision to chose the power of the CB. If more bits are used in the genes then the precision achieved is not significant, while if less bits are used there will be a lack of precision.

A special case is the CB with zero power. As the CB have also a minimum power C_i^m, the powers between 0 and C_i^m will be penalized by the constraint function. To handle this case the following procedure is adopted to assign the power to capacitor i.

$$C_i := \begin{cases} 0 & \text{if } C_i < C_i^m/2, \\ C_i & \text{otherwise} \end{cases} \tag{4.11}$$

For example in the previous case, as the minimum power is 5 Mvar the assigned power is 8 Mvar. While if the result of equation (4.10) was less than 2.5 then the assigned power will be 0 Mvar. If the result is between 2.5 and 5 then the penalization function is applied, assigning worse values to powers closer to 2.5 (see equation (4.5)).

If there are k available capacitor banks, the chromosomes are represented in strings of $12k$ bits. In this way, the search space for the algorithm consists of 4096^k variables (for $k = 15$ it is a number of 55 ciphers). Note that the whole set of variables is not explored by algorithm. It is impractical and computationally not affordable. In consequence it is impossible to execute a brute search algorithm in this space. Indeed it is not affordable to do a brute search in the following search space.

Suppose that the allowed range for capacitor i is $(0, C_i^M)$, and that to explore this space the algorithm picks 10 points from 0 to C_i^M. If the total number of available buses is k, the search space has a size of 10^k. If $k = 15$, the search space is so large that can not be handled by a standard programming language. Only if k has a value lower than 5, the program can handle it. However, the case with only 5 CBs is not considered in the Skagerak Nett networks, it would fall away of the main problem. It is possible to reduce the search space by reducing the steps at each interval to value lower than 10. Indeed this would not allow a fairly exploration. In any case, the reason to discard the brute search algorithm is that it can not be handled by a standard programming language in a standard computer.

For this reason the actual tools to solve the OCP are the genetic algorithms described at section 3.2.2. Standard parameters for the genetic are shown in table 4.9. However they can be modified to obtain better solutions.

Table 4.9: Genetic Algorithms standard parameters

Parameter	Value
Population size	300
Offspring size	299
String lenght of each CB	12
Number of generations	40
Crossover probability	0.5
Mutation probability	0.2
Selection operator	Tournament (3.2.2)
Initial population	Random
Crossover operator	Two-point crossover (3.2.2)
Mutation operator	Random two bits (3.2.2)
Survival operator	One individual elitism

The complete code of the algorithms in Python can be found at the appendix.

4.5.2 Algorithm Performance

The performance of genetic algorithms are governed by the crossover and mutation probabilities, the size of the population and the number of generations. The tests showed what are the most effective values in order to find the optimal solutions. The number of generations can be enlarged in the cases that the convergence is not achieved before the algorithm finish, running the algorithm several times usually shows that 150 to 200 generations are enough. The crossover probability can be modified between 0.3 and 0.75 leading to good results, while the mutation probability is better kept in values below 0.4. The reason is that a high rate of mutation introduces too much variability and do not allow the good solutions to grow within the population.

Although it can seem illogic, a large population does not guarantee good results because two much diversity makes the algorithm hard to converge. One important factor is the number of bits used for each chromosome. The standard values that have shown a good performance are in table 4.9.

4.6 Results

The following list contains the strategy followed to obtain the best solutions.

1. Use more than one algorithm.
2. Run the algorithm 15 times with the same parameters to check the contingency of the solution.
3. Try a set of 5 different values for crossover probability and mutation probability.

4. Try different selection procedures.
5. Try different crossover and mutation operators.
6. Try different survival operators.
7. Use a seeding population.
8. Suppress one or more functions of the objective function and inspect how they differ.

Tables 4.10 and 4.11 show the best solutions obtained, with regards of the total costs, by the three genetic algorithms elitism selection (ESGA), $(\mu+\lambda)$-genetic algorithm (MPLGA) and (μ, λ)-genetic algorithm (CMLGA). All solutions have been obtained independently of each other.

Table 4.10: Telemark Solutions

CB	No CBs	ST1	ST2	ST3	ST4	ST5	ST6
1	0.00	29.90	29.48	29.82	29.31	29.08	29.74
2	0.00	29.33	13.78	0.00	28.13	18.76	13.72
3	0.00	0.00	14.79	14.85	0.00	10.51	13.13
4	0.00	35.25	35.79	35.97	37.40	38.76	37.05
5	0.00	9.41	8.48	14.07	7.53	0.00	0.00
6	0.00	73.42	74.64	68.59	55.96	56.03	66.91
7	0.00	0.00	0.00	14.73	0.00	23.53	18.41
8	0.00	0.00	0.00	0.00	7.59	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	29.94	29.96	29.97	29.98	29.97	29.99
11	0.00	14.89	15.00	14.98	14.86	14.85	14.86
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	9.90	0.00	0.00
Total costs	320.84	252.11	252.16	252.17	252.64	252.68	252.67
Losses (MW)	16.69	16.55	16.55	16.55	16.55	16.55	16.55
Losses costs	242.10	240.13	240.09	240.08	240.01	240.12	240.06
RP ex. (Mvar)	190.37	19.99	19.99	19.99	19.99	19.99	19.96
RP Costs	78.74	0.00	0.00	0.00	0.00	0.00	0.00
CBs invest.	0.00	11.78	11.83	11.85	12.37	12.32	12.37
O&M costs	0	0.21	0.24	0.24	0.27	0.24	0.24
Num. of Tr. St.	0	7	8	8	9	8	8
Total RP	0.00	222.13	221.92	222.97	220.67	221.49	223.80
Maximum RP	0.00	73.42	74.64	68.59	55.96	56.03	66.91
Mean RP	0.00	17.09	17.07	17.15	16.97	17.04	17.22
Minimum RP	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Benefits	0.00	68.73	68.68	68.68	68.20	68.16	68.18
Algorithm	-	ESGA	ESGA	ESGA	CMLGA	CMLGA	MPLGA
NGEN		200.00	150	150	150	150	150
CXPB		0.67	0.75	0.75	0.6	0.5	0.6
MUTPB		0.20	0.5	0.2	0.35	0.2	0.4
POP		300.00	300	300	300	300	150

Table 4.11: Vestfold solutions

CB	Nu. CBs	SV1	SV2	SV3	SV4	SV5
1	0	8.25	6.02	0.00	0.00	6.45
2	0	24.15	15.37	0.00	0.00	22.76
3	0	0.00	0.00	0.00	0.00	0.00
4	0	0.00	0.00	0.00	0.00	0.00
5	0	0.00	0.00	0.00	0.00	0.00
6	0	0.00	0.00	0.00	0.00	0.00
7	0	12.85	0.00	0.00	6.17	0.00
8	0	0.00	0.00	8.34	0.00	0.00
9	0	0.00	0.00	0.00	0.00	0.00
10	0	0.00	0.00	0.00	0.00	0.00
11	0	0.00	0.00	6.75	0.00	0.00
12	0	0.00	0.00	0.00	0.00	0.00
13	0	18.13	0.00	11.96	20.07	6.34
14	0	0.00	11.25	0.00	6.27	6.44
15	0	0.00	0.00	0.00	0.00	0.00
16	0	0.00	13.38	7.94	0.00	0.00
17	0	0.00	19.79	16.28	14.22	18.98
18	0	8.95	9.33	7.95	13.20	15.41
19	0	0.00	0.00	0.00	0.00	0.00
20	0	0.00	0.00	0.00	12.20	9.35
21	0	14.95	10.34	12.77	0.00	9.23
22	0	0.00	0.00	0.00	13.52	0.00
23	0	0.00	0.00	0.00	0.00	0.00
24	0	0.00	0.00	0.00	16.25	0.00
25	0	0.00	0.00	0.00	0.00	0.00
26	0	0.00	0.00	7.18	16.06	0.00
27	0	0.00	0.00	0.00	8.63	9.96
28	0	16.90	0.00	0.00	0.00	0.00
29	0	0.00	11.92	0.00	0.00	0.00
30	0	0.00	0.00	10.12	0.00	0.00
31	0	13.44	14.48	6.60	0.00	7.61
32	0	0.00	9.90	13.14	0.00	0.00
33	0	24.08	8.61	9.71	16.51	12.91
34	0	0.00	0.00	11.72	0.00	7.37
35	0	0.00	0.00	0.00	0.00	0.00
36	0	0.00	0.00	0.00	0.00	7.63
37	0	0.00	0.00	7.17	6.20	0.00
38	0	6.02	19.69	9.38	6.65	14.12
Total costs	209.29	169.47	169.51	173.30	172.81	169.97
Losses (MW)	9.00	8.69	8.64	8.61	8.65	8.66
Losses costs	130.54	126.03	125.35	124.86	125.45	125.62
RP ex. (Mvar)	190.37	84.83	84.88	89.99	84.79	79.86
RP costs	78.74	33.16	33.16	35.23	33.16	31.08
CBs investment	0.00	9.99	10.65	12.76	13.82	12.86
O&M costs	0.00	0.30	0.35	0.44	0.38	0.41
Num. of Tr. St.	0	10	12	15	13	14

Continued on next page

CB	Nu. CBs	SV1	SV2	SV3	SV4	SV5
Total RP	0	147.72	150.08	147	155.96	154.57
Maximum RP	0	24.15	19.79	16.28	20.07	22.76
Mean RP	0	3.89	3.95	3.87	4.1	4.07
Minimum RP	0	0.00	0	0	0	0
Total Benefits	0	39.81	39.77	35.99	36.47	39.32
Algorithm	-	ESGA	ESGA	CPLGA	PMLGA	ESGA
NGEN		200	150	150	150	200
CXPB		0.8	0.75	0.6	0.65	0.65
MUTPB		0.5	0.5	0.35	0.2	0.2
POP		300	300	200	150	300

Chapter 5

Solution Analysis for The Skagerak Nett Network

The solutions presented in Chapter 4 are analysed here in technological and economic terms. The technological analysis includes the verification of constraints. The analysis will conclude with the proposal solution.

The first thing to point out is that all the solutions satisfy the constraints: voltage variation lower than 3 % and power factor variation limits. Secondly, although not all the solutions are optimal, their cost values are very similar. This means that the solutions are in fact accumulating around near optimal solutions.

5.1 Telemark

The no investment solution has a present cost of 320 million NOK along 20 years. The 75 % of these costs corresponds to line losses, 242 million NOK. Reactive power costs are only 78 MNOK. Optimal solutions can achieve savings of around 68 million krones.

5.1.1 Technology

The majority of solutions show that optimal CBC tend to concentrate the reactive power supply on the first siz CBs. Total reactive power supplied is around 221 Mvar by eight CBs of a total of 13 available buses. The total maximum reactive power that can be installed is 366.5 Mvar D.2.

CBs numbers one, four, ten and eleven have a quite regular value along all the solutions. Number one is fitted to a value of 29 Mvar, number four to values around 37 Mvar, number ten to 30 Mvar and number eleven to 15 Mvar. Bus number six does not show this same regularity but at least the solutions show that this bus needs a big amount of reactive power supply. This is a bus that admits 75 Mvar as maximum reactive power supply. The reactive power in that transformer station is divided in 4 different CBs of sizes of $(20, 20, 20, 15)$ Mvar. The solutions with less than 60 Mvar at that bus can use only three CBs, while the other ones have to use the four. The situation is the same for other transformer stations as is listed in table D.2. It is worth noting in the other side that there are some buses that do not need any CB, these are buses nine and twelve. In addition, the majority off solutions do not have any CB placed at buses eight and thirteen. These trends are easily visualized in graph 5.1.

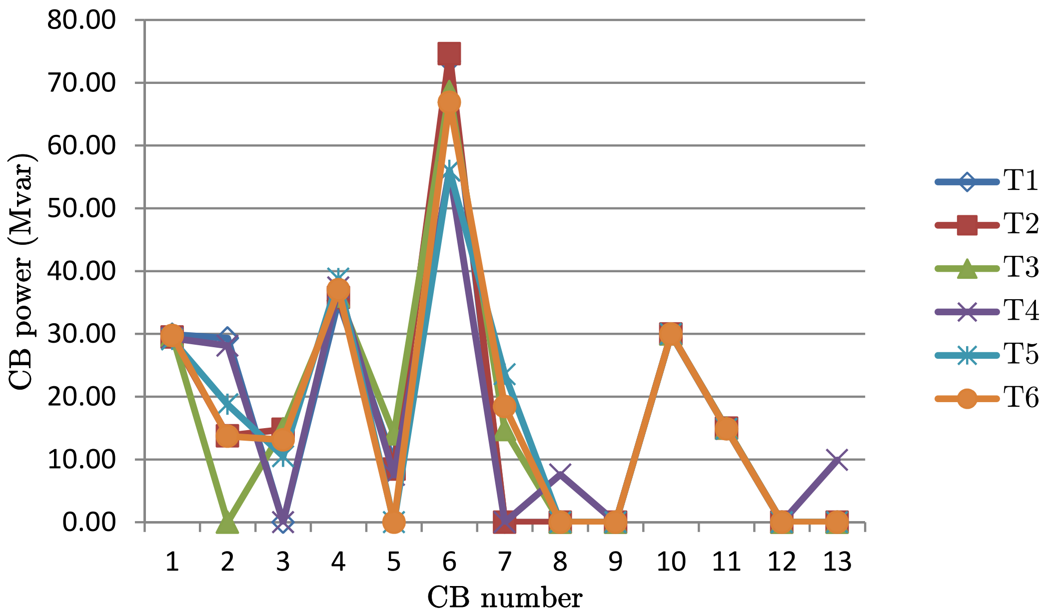

Figure 5.1: Telemark powers of CBs for solutions ST1 to ST6

Solutions 1 a 2 are very close in all the parameters: power losses, reactive power exchange, similar CBs powers and investment. The only difference is that they have capacitors 2 and 7 exchanged. These buses are Myrene and Kylve (respectively) and are connected through a third bus (Meen). Both buses have similar loads and are connected to two power lines.

Power losses have suffered slight modifications with all the solutions. All the CBC only can reduce losses in power lines by 140 kW. This produce a power loses cost stuck to 240 million krones and savings of only 2 million krones. In front of this, there are the reactive power losses which are reduced to 0, what means savings of 78 million krones in this aspect. The cause is that the reactive power exchange is reduced below 20 Mvar. This is achieved through three available buses that are connected to the bus where the reactive power exchange is measured.

5.1.2 Economy

Investment costs of the solutions are established around 12 million krones. Solutions one and two, which are the ones with the lowest cost, have the lowest investment. The operation and managements costs are around 240 thousand krines, that corresponds to 8 new CBs. The differences in total costs between best and worst of these 5 solutions are around half million krones. This amount is due mainly to the investment in CBs. In the rows of total reactive power and investment costs, it can be observed that a major investment or a major total reactive power supply does not guarantee a lesser overall cost.

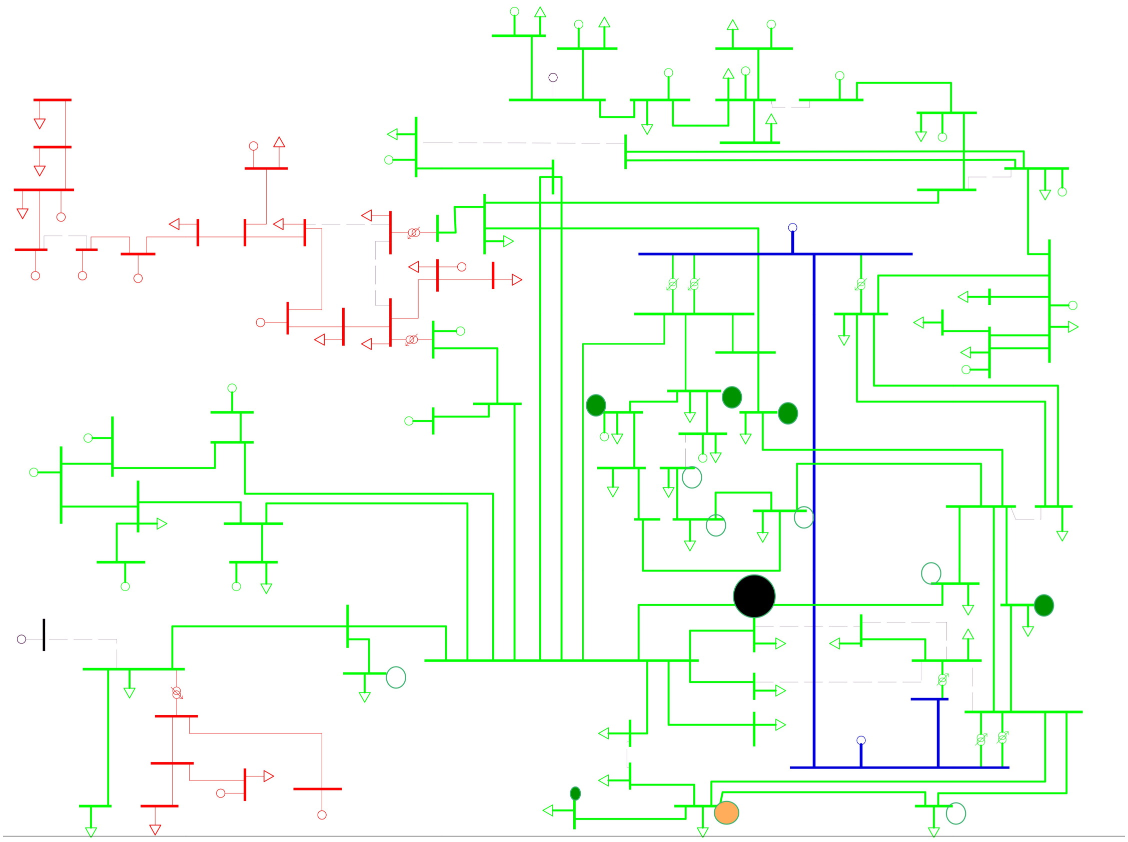

Figure 5.2: Telemark transmission network with voltage levels 300 kV (blue), 125-132 kV (green) and 56 kV (red). Available buses marked with green circle. Sizes of CBs solution ST1 represented by proportional circles (green, orange, black).

5.2 Vestfold

The no investment solution has a present cost of 209 million krones. The losses in lines are 9 MW which cause total costs of 130 million krones. The reactive power exchange has 190 Mvar what will suppose a charge of 78 million krones along the 20 years of the analysis (this is the equivalent present value). It should be noted that the reactive power exhange is the sum of the reactive powers exchange at both networks (see note at (4.9)). Among these solutions, the difference in overall costs are at most around 3 million krones.

5.2.1 Technology

Losses in power lines do not show a significant reduction, just around 350 kW. in overall costs this suppose around 5 million krones. The reactive power exchange is established between 85 and 95 Mvar. The best solution, SV1, has a total of 10 used transformer stations, while the other solutions have 13 or 15, of a total of 38 available buses. There no exist clear patterns about the amount reactive power to place at each available bus, probably because there are many available buses. However, these solutions show that some buses do not have need of reactive power; buses 3, 4, 5, 9, 10, 12, 15, 19, 20, 23, 25 and 35. Reactive powers of CBs range from 6 to 20 Mvar. The total reactive power supplied by CBCs is between 134 and 155 Mvar. Figures 5.3 and 5.4 show the profile of the CBCs of solutions SV1 to SV5.

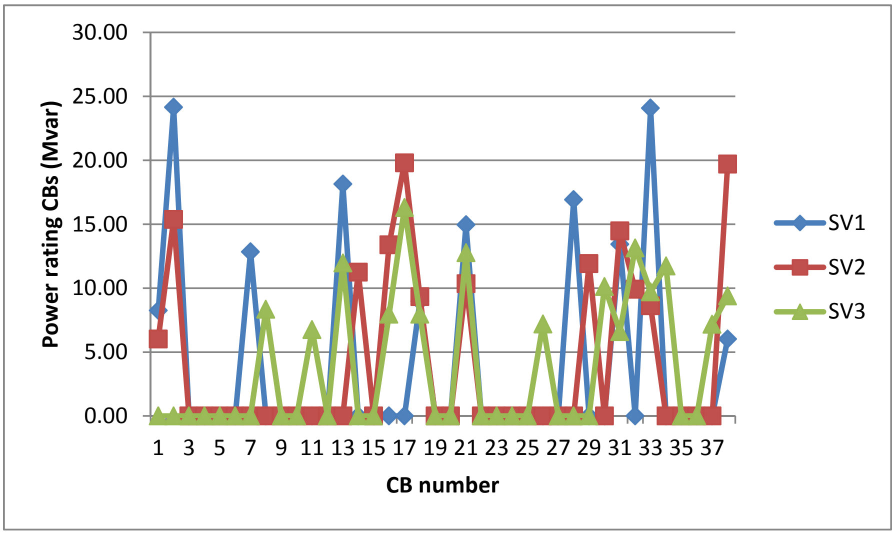

Figure 5.3: Vestfold powers of CBs for solutions SV1, SV2 and SV3

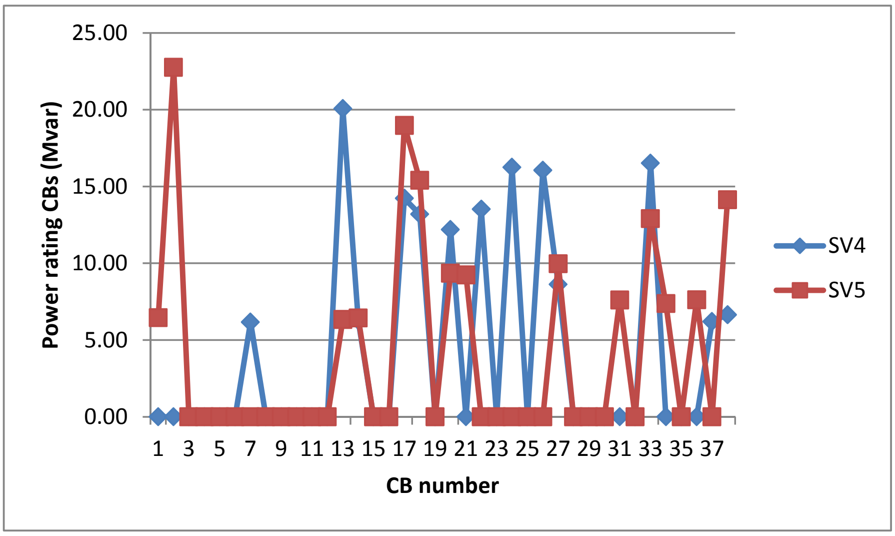

Figure 5.4: Vestfold powers of CBs for solutions SV4 and SV5

5.2.2 Economy

Benefits of these solutions range from 35 to 39 million krones. These are mainly due to reduction in reactive power costs, losses savings only represent 5 million krones. The best solution has actually the lowest investment in CBs, 10.65 million krones. Again the importance of placing reactive power at the right stations. Maintenance costs are around 400.000 NOK for each solution.

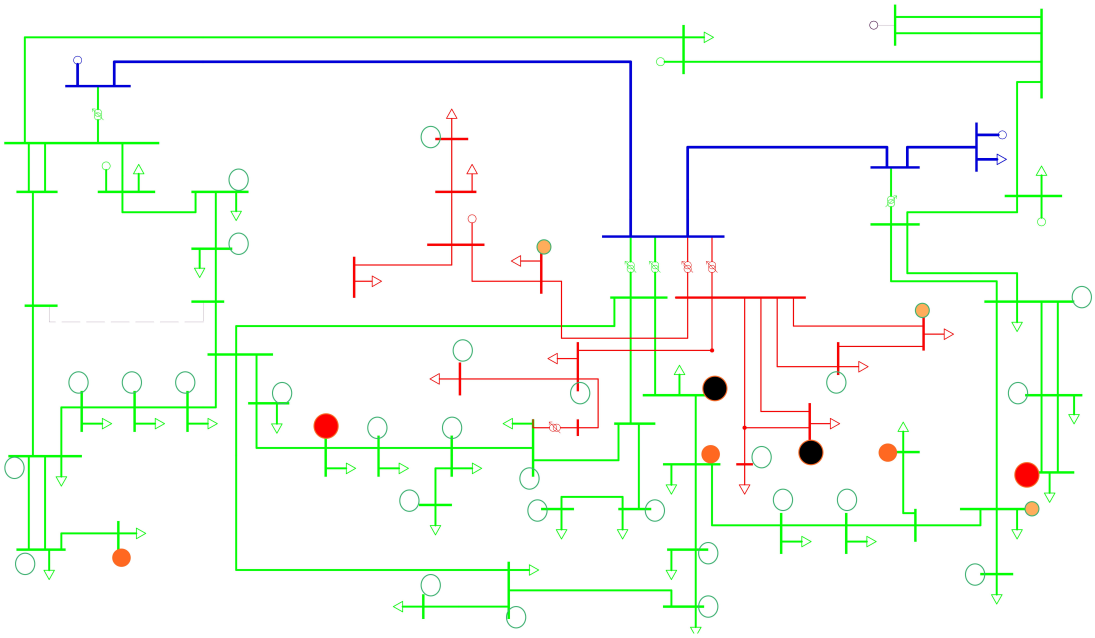

Figure 5.5: Vestfold transmission network with voltage levels 300 kV (blue), 130 kV (green) and 66 kV (red). Available buses marked with green circle. Sizes of CBs solution SV1 represented by proportional circles (orange, dark orange, red and black).

5.3 Solutions

The savings that can be achieved with the solutions in Telemark almost double the savings in Vestfold. The main reason is that in Vestfold the reduction of reactive charge has less impact. In both networks the savings in line losses are not significantly reduced, although in Vestfold the savings triple the ones in Telemark in this aspect. However the total reactive power to be installed in Telemark is greater than in Vestfold, 221 Mvar versus 151 Mvar. The number of transformer stations that have to allocate CBs is lower in Telemark than in Vestfold, although in percentage less than half of the available buses in Vestfold are used.

Telemark is the network that can cause the highest costs and the one where the largest savings can be achieved. However, best solutions of both networks require similar investments from 10 to 13 million krones. In both networks, a large reduction in reactive power costs can be achieved.

Disposing of various near optimal solutions a post analysis can be performed including the particular conditions of the network. The final decision will include: number of CBs, number of switchgears and capacitor banks sizes (which are agreed with manufacturer in addition to tolerances parameters). The solutions in tables 4.10 and 4.11 state the best buses to allocate CBs, which is an important factor in the investment decision.

The optimal solutions for the Skagerak Nett networks are solutions ST1 and SV1, because they are the ones that require the fewest investment and achieved the largest benefits. These solutions are optimal in this economic sense. In addition they both satisfy the voltage and power factor constraints.

To evaluate how efficient are the solutions some more computations are done. The optimization is

Table 5.1: Solution with the only objective of reducing losses in Telemark

Capacitor Bank	Telemark
1	19.87
2	0.00
3	0.00
4	0.00
5	6.49
6	46.89
7	7.56
8	0.00
9	0.00
10	6.55
11	14.40
12	0.00
13	9.94
Total costs	237.17
Losses (MW)	16.35
Losses costs	237.17
RP ex. (Mvar)	126.21
RP Costs	-
CBs investment	7.60
O&M costs	-
Number of CBs	7

performed taking into account just the power losses. In this way, the only objective is to reduce power losses in the lines. The results are shown in tables 5.1 and 5.2.

Table 5.2: Vestfold solution with the only objective of reducing losses

CB	Vestfold	CB	Vestfold
1	0.00	24	12.34
2	18.38	25	0.00
3	0.00	26	6.37
4	0.00	27	14.24
5	0.00	28	0.00
6	8.77	29	10.74
7	0.00	30	0.00
8	11.44	31	0.00
9	0.00	32	0.00
10	0.00	33	0.00
11	0.00	34	6.62
12	0.00	35	0.00
13	0.00	36	0.00
14	0.00	37	7.98
15	0.00	38	0.00
16	0.00	Total costs	123.97
17	11.24	Losses (MW)	8.55
18	7.31	Losses costs	123.97
19	13.97	RP ex. (Mvar)	101.25
20	0.00	RP costs	-
21	0.00	CBs investment	12.24
22	0.00	O&M costs	-
23	0.00	Number of CBs	12

The total costs of these CBCs show that if the objective function only account for reduction of line losses, then their values are 237 and 124 MNOK for Telemark and Vestfold networks respectively. Although these values are also obtained with the ESGA algorithm and they are not the same solutions as ST1 and SV1, they give an idea of how much the total costs can be minimized. They are lower bounds for the objective function of the OCP. Note that if that values are added to the investment in the CBCs then they get closer to the values of the proposed solutions (252 and 169 MNOK).

Chapter 6

Discussion

Capacitor Banks

Shunt capacitor banks are used by utility companies to compensate reactive power. Other technologies exist for this purpose, but capacitor banks are widely used because of their low cost in terms of maintenance and investment. They can, however, cause problems in the electric grid if they are not correctly placed and sized. Some limitations have to be accomplished, which has been included in the problem formulation as constraints.

The transmission network connects the power plants with the distribution network. When capacitor banks are placed at the start point of the distribution feeder, they will supply the loads with part of the required reactive power. This reduces the production of reactive power at power plants and its transportation through power lines. The power lines increase their capacity as they do not have to transport as much reactive power.

Problem formulation

The problem solved, Optimal Capacitor Problem (OCP), is an optimization problem with constraints. The objective function has been established from the costs of such aspects of the network which can be improved and measured: reactive power exchange, voltage levels, investment and power line losses. Thus, the objective function includes the following specially selected cost elements: kilowatt-hour price, reactive power price, capacitor costs, maintenance costs and installation costs.

The cost of each Capacitor Bank (CB) has been estimated by the formula in Table 4.5 which gives a fair estimation. In this way large CBs are penalized by the objective function, which can lead a solution with smaller CBs to have lower global cost. The investment requirements for each transformer station has been estimated to approximately 500 KNOK. The exact number of CBs needed in each station has been taken into account by the algorithm, by using the transformer station data available from Skagerak Nett.

The OCP has been designed to optimize a single function. However, there are other approaches that make use of a multi-objective function [13]. Using a single function is a good approach because it simplifies the interpretation and definition of the objective and weights all the aspects with a practical real approach onto monetary values. The costs have also been calculated using the present value method, which means that future costs are being compared to the initial investment in CBs. Although the investment can be delayed in time, this has not been considered here. Other objectives described in the literature and not considered her are: voltage profile improvement, system stability improvement and power factor improvement. Nevertheless, voltage level and power factor aspects have been included only in the penalization function in order to avoid unfeasible solutions for the system. The constraints implemented in the algorithm are maximum voltage variation, power factor limits and minimum and maximum number of CBs. They have been implemented modularly, which means that there is the possibility to choose the constraints that take part in the optimization. All the functions have been implemented separately with Python 2.7: constraints functions, objective function, Power System Simulator for Engineering (PSS/E) interaction function, constraints report and cost functions. Dividing the costs into each aspect allows for performing a post analysis.

The objective function can be defined in several ways, depending on the data available. Other approaches may include multi-objective functions or weighted costs. Also, some other measures or calculations can be taken into the electric network like power system stability indexes. In this way, the OCP can be defined in multiple ways and admit multiple approaches. It depends on what the objectives are and how the objective function is defined.

The optimization begins by defining the objective function and the model. The accuracy of the approach will determine how well the simulations and results can be exported to the real network. In this project the most reliable values are the active power losses and the constraints. The economic values are approximated as explained below.

Assumptions

The data used in the optimization process comprises the following information: load figures of active power peak demand, network impedance matrix, active power price, reactive power price, reactive power exchange, actual voltage levels and investments costs.

Some assumptions have been made in order to establish the objective function that computes the costs, such as economic and technological assumptions. These assumptions define the objective function. Other sets of the assumptions would lead to other approaches with other results.

Economic assumptions

- Discount rate and other rates.
- Active and reactive power prices.
- Investment in CBs, switchgears and installations are based on practical approximations.

Technological assumptions

- Losses are not significant in capacitor banks and distribution transformers.
- Load figures and measurements from PSS/E fit to the purpose of optimization.

Algorithms

There exist several implementations of genetic algorithms. The chosen one is in Python, jointly with the package DEAP (Distributed Evolutionary Algorithms in Python). Nevertheless, there are other programming languages with implemented genetic algorithms available at on-line sites. In this case, Python, although it can interact with those programming languages, was the native language to interact with PSS/E 33.3, thus, it would be more efficient to execute genetic algorithms written with Python. The definitive choice on the DEAP package is a result of various trial searches for the best algorithm. DEAP is a framework for evolutionary algorithms with multiple tools available. It allows building up your own evolutionary algorithm by selecting the desired operators and parameters like: roulette wheel, tournament, one point or two point crossover and uniform mutation among others.

There are other global optimizations algorithms that has not worked in this problem: brute search, simulated annealing, Nelder-Mead descend algorithm (all available with the Scipy package). There is no commercial software with a module for solving the OCP. When doing this in your own way you have more room for defining the objectives and the algorithm used to solve the problem.

Genetic Algorithms

Genetic algorithms have been applied to the OCP. They are suitable because they are not dependent on the particularities of the problem. They adapt well to any kind of optimization problem and they are consistent because they can be applied to networks of any size. The advantages that make them suitable for the OCP are the following:

- Easily adaptable to the problem
- Modifiable with parameters
- Randomness of starting population
- Executable multiple times
- Modular construction through operators
- Wide exploration scheme
- Independent of starting set of solutions
- Can solve constrained problems
- Can handle large solution space
- Solutions to complex problems, as OCP, that cannot be solved with a deterministic algorithm

However, genetic algorithms have been reported to include some disadvantages

- Convergence to local extremes, instead of global extremes.
- Slow convergence.

- Stochastic algorithm without 100 % probability of finding the optimal solution.

These problems have been solved by modifying the genetic algorithm with the parameters and operators, or trying different genetic algorithms like the $\mu + \lambda-$ Genetic Algorithm (MPLGA) and $\mu, \lambda-$ Genetic Algorithm (CMLGA). The algorithm with the best performance has been the Elitism Selection Genetic Algorithm (ESGA) because it returned the best results. All the algorithms are stopped by a maximum number of generations criterion, which is also used in [32]. This has not affected the solutions as it has been checked that the solutions actually converged. The algorithm can not guarantee an optimal solution, but there is a high probability of finding one if enough runs of the algorithm are performed.

Solutions

Some of the best results obtained from the algorithms are presented in section 4.6. The final optimal solutions to the OCP are shown in Table 5.1 and Table 5.2. The solutions show that the optimization considerably reduces the reactive power exchange, while the reduction of active power losses is low.

The solution for Telemark has the lowest cost and the lowest number of stations with CBs. The total number of CBs is 14. Four of them are localized at bus 6, where all the near-optimal solutions have placed a big amount of reactive power (see fig. 5.2). The powers of the CBs are listed in Table 6.1 in increased order and showing the detailed number of CBs in each station (depending on the number of transformers at each station, see table D.2). There are 14 new CBs at Telemark distributed in 7 transformer stations. The investment amounts to 11.78 MNOK. This is the best solution for Telemark because it minimizes the costs defined in the objective function. The economic savings after the period of 20 years are of 68.73 MNOK. The special characteristic of this solution that stands out compared to the others is that the number of new CBs is the lowest.

Table 6.1: Detailed distribution of CBs at each station in Telemark.

Bus		Power (Mvar)	CBs (Mvar)
5	LANGESUND	9.41	9.41
11	SKOTFOSS	14.89	14.89
2	MYRENE	29.33	15, 14.33
1	FROGNER	29.90	15, 14.90
10	ÅRHUS	29.94	15, 14.99
4	BREVIK	35.25	20, 15.25
6	ROLIGHETEN	73.42	20, 20, 20, 13.42
	Mean	31.73	

The solution for Vestfold also has the characteristic of the solution with the lowest costs and the lowest number of CBs (see Table 4.11). It has 13 CBs distributed in 10 stations. The investment amounts to 10 MNOK. While the reduction in losses is not the largest among the solutions, the reduction of reactive power exchange is the largest. The total cost savings after 20 years are 39.81 MNOK. Table 6.2 shows the details of the Capacitor Bank Configuration (CBC) solution.

Table 6.2: Detailed distribution of CBs at each station in Vestfold.

Bus		Power (Mvar)	CBs (Mvar)
38	VEGGBAKKEN	6.02	6.02
1	BRåR	8.25	8.25
18	BENTSRUD	8.95	8.95
7	RØREÅSEN	12.85	12.85
31	DOLVEN	13.44	13.44
21	SLAGEN	14.95	14.95
28	BUGÅRDEN	16.90	12.50, 4.40
13	SVELVIK	18.13	11.25, 6.88
33	HEIMDAL	24.08	12.30, 11.78
2	RAKKÅS	24.15	24.15
	Mean	14.77	

Optimality

The solutions presented above are the best solutions obtained. The question that arises is if in fact there exists better solutions. They still could be found with genetic algorithms, but as these are stochastic algorithms, they cannot tell us if the final solution is the optimal one. Neither can they tell how many optimal solutions exist. We have to content ourselves with near optimal solutions. A external analysis would have to be carried to see how good these solutions are . There are two issues: the first is to continue finding better solutions (by whatever method), and second, try to prove that the found solution is optimal or practically optimal[1].

The first issue has been carried out in this project by executing several times the described algorithms by the methods explained in section 4.6: using three different algorithms and varying their parameters (probabilities, number of generations and population).

The second issue of verifying the optimality of the solution has been approached by the discussion in section 5.3. A lower bound has been proposed by performing the optimization for a reduced objective function that only takes into account the power losses and the constraints. The lower bounds found are 237 MNOK and 124 MNOK for Telemark and Vestfold respectively[2].

They also give lower bounds for the active power losses: 16.35 MW and 8.55 MW respectively. Now these values can be compared with solutions ST1 and SV1, whose losses are 16.55 MW and 8.69 MW respectively. Although it has been pointed out that the reduction in loses are only 0.140 MW and 0.400 MW, the lower bounds 16.35 MW and 8.55 MW are close enough to the optimal solutions, therefore 237 MNOK and 124 MNOK are also close lower bounds of 240 MNOK and 125 MNOK (see tables 4.10 and 4.11).

The algorithms used are of the same class, Genetic Algorithm (GA). Although it would be more consistent to obtain same results by other algorithms, the other ones have failed to work and it is

[1] Here by practically optimal we understand a solution such that the difference with the optimal solution is below a significant difference, for example 1 thousand krones. So solutions that have costs of 215.009.100 NOK and 215.010.000 NOK are equally optimal although in this case the best one is the former. Another way to say this is that they have the same 5 significant digits, $215.01 \cdot 10^6$.

[2] This means that the optimal solutions, if are different of ST1 and SV1, have costs between 237 and 251 MNOK and between 124 and 169 MNOK.

harder to obtain good results with them. GAs are easier to handle. Although many algorithms can be tried, the only purpose would be to find better and better solutions, not to prove the optimality of the solution.

The solution obtained is not unique. This is caused by the nature of the genetic algorithm. They are stochastic algorithms that may not converge towards the same solution at each execution. The proposed solutions, however, share common characteristics, and this tends to confirm the proposed optimal solutions[3]. In first place, they have similar costs. The total cost is in the range of MNOK, which means that solutions within a range of one million can be considered to be equally optimal.

Secondly, optimal solutions have CBs at specific buses. This means that these are important buses that have to be supplied with reactive power. Solutions show that supplying more reactive power to the network does not mean we get lower losses or lower reactive power exchange. The placement of the reactive power source is important.

It cannot be said that the best solution presented minimizes the costs of operation of the network installing CBs, because the minimum of the objective function is not actually known. The presented solutions are at least close to the optimal solution and they are considered good enough because the algorithms have been executed several times and a lower bound for the costs has been depicted.

The ideal case would be that all the executions of the algorithm converge to the same solution. However this has not been the case. The best solution continues being the best solution although the executions converge to slightly different CBCs. What is worth noting is that the algorithm usually converges to the same solution if it is executed with the same parameters of crossover, mutation and number of generations.

The present situation is that one can obtain different solutions by different executions of the algorithm, which at least share the same effect on the system regarding reactive power compensation, voltage levels and line losses.

In this way, the optimization gives a general view of what can be achieved, how much the costs can be reduced and the CBC that leads to it. No previous idea was conceived of what can be achieved with the reactive power compensation. It has to be noted that the initial population of each genetic algorithm is totally random. In this way, the convergence of the algorithms respond to a real optimization process. The problem is to make sure that the convergence is approaching the optimal solution.

[3] The algorithm is robust in the sense that the output results have common characteristics

Chapter 7

Conclusions

Capacitor Banks

Capacitor banks are good devices for improving the network, and are already used by Skagerak Nett. What has been achieved in this project is a solution to the Optimal Capacitor Problem (OCP) applied to a particular transmission network. The optimization satisfies the constraints that govern the performance of a power system.

The optimization is based on reduction of costs, which will account for reduction in line losses and reactive power exchange.

Algorithms

Genetic algorithms perform satisfactory to the optimization problem with constraints. They are applied to several optimization problems in electric power systems, in particular to the placement and sizing of capacitor banks in a large network.

Genetic algorithms are scalable and offer a wide range of possibilities to attack the problem. If a scheme or operator do not return good results, the algorithm parameters are modified. Any other prospective solutions can be tested with the fitness function of the algorithm. However, the genetic algorithm does this with thousands of solutions in each execution.

The algorithms have been executed multiple times to assure reliability, robustness and consistence. Each execution converges to optimal or near-optimal solutions, when the appropriate parameters are set: crossover probability between 0.5 and 0.75, mutation probability from 0.2 to 0.5, population in the range of 200-300 individuals and the number of generations around 200.

The applied algorithms are the Elitism Selection Genetic Algorithm (ESGA), $\mu + \lambda-$ Genetic Algorithm (MPLGA) and $\mu, \lambda-$ Genetic Algorithm (CMLGA). The latter was the most valuable as it returned the best results for both networks.

Solutions

The consequence of using genetic algorithms is that solutions are not unique. However they share the same traits: buses and sizes. This has been verified after a sufficient amount of results.

Optimal sizes and placements have been found, as all the solutions include the same scheme. The solutions show that the optimization has an impact on reactive power exchange, while the reduction of active power losses is low.

The optimal solutions are Capacitor Bank Configurations (CBCs) that affect 7 and 10 transformer stations in Telemark and Vestfold. The CBC solution in Telemark applies 14 capacitor banks in these stations, with power ratings from 9 to 20 Mvar. The station that allocates more reactive power has 73 Mvar, and the rest are below 35.25 Mvar. The optimal CBC solution in Vestfold applies 13 Capacitor Banks (CBs) with power ratings from 6 to 15 Mvar. The highest power rating in a transformer station is 24.08 Mvar.

These solutions will accomplish the objectives of reduction of losses and reduction of reactive power bill. The most significant savings will occur in the Telemark network, which amounts to 68 MNOK, while at Vestfold they nearly reach 40 MNOK. However, the investments are almost the same, 12 MNOK at Telemark and 10 MNOK at Vestfold. The savings are not equally distributed over the calculation period because of the computations with the discount rate.

Apart from the savings the installation of CBs will free system capacity and will support voltage stability and reactive power supply.

Recommendations

The solutions explained above will achieve all the initial objectives: reduction of overhead lines active losses and billing charges. In addition the networks will benefit from voltage and var support and increased system capacity. Future system expansion could benefit from a major system capacity.

The recommended CBCs for improving the grid are the optimal solutions described at tables 6.1 and 6.2.

The specified CBs have to be installed in the specified transformer stations which is the reflect of the simulation. As has been checked in the solutions, the costs are sensitive to the placement of CBs.

Future Work

There are three fields where the work can continue. Firstly, if the optimization part is going to be explored further, trying to find better solutions, other algorithms and methods can be carried on. In this aspect there is plenty of research and publications, mostly related to genetic algorithms.

Secondly, investigating other approaches described at the introduction. This will lead to other system models and objective functions, and will span the scope of the problem, which can embrace questions that could emerge in the future. Adaptation of the optimization method to the particularities of the network and the constraints is another aspect in this field.

Thirdly, the actual installation of CBs must be realized have to be put into practice. This will imply further study on the transformer stations regarding availability of space, expansion necessities and harmonic resonance, in addition to agreements with the manufacturers on CBs ratings and tolerances.

Appendix A

Capacitor Banks

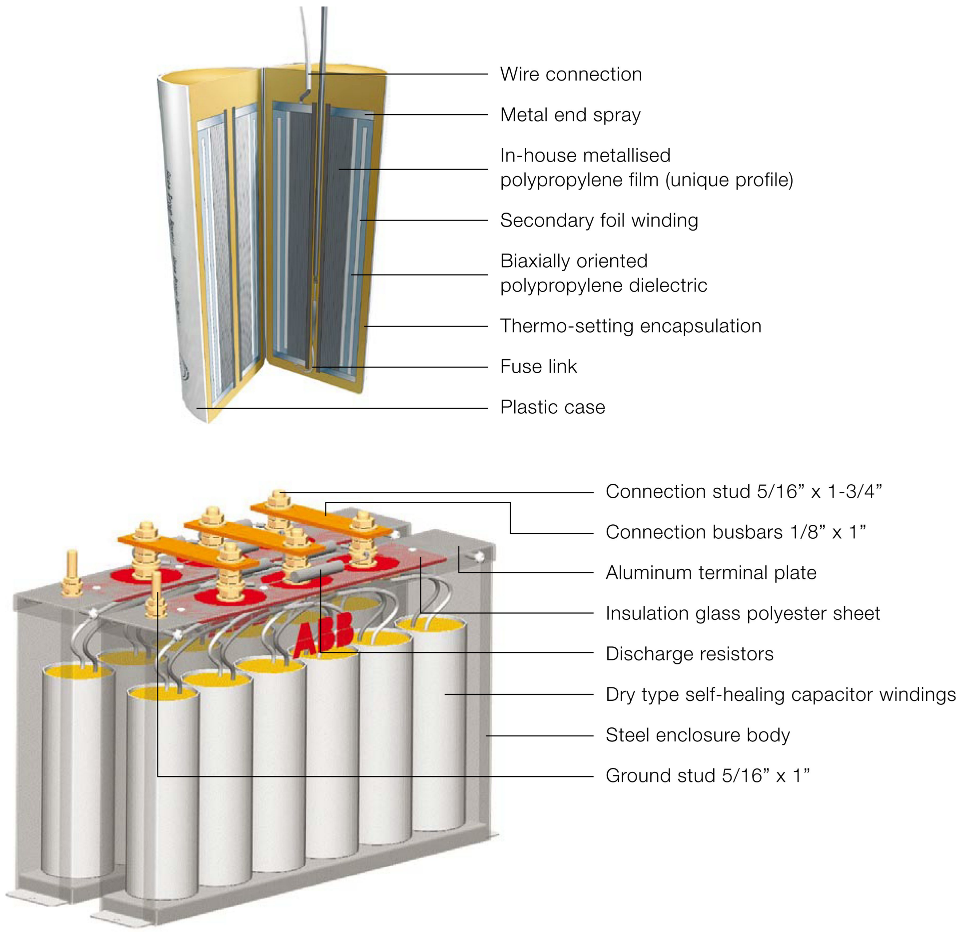

Figure A.1: Low voltage CB unit, which has the same characteristics as a high voltage unit [4].

Figure A.2: Entire CB unit in a transformer station [3]

Appendix B

Scripts

1. ESGA algorithm
2. Fitness function
3. Interaction with Power System Simulator for Engineering (PSS/E)
4. MPLGA
5. CMLGA

```
#ESGA ALGORITHM IN PYTHON

#! /usr/bin/python

# This line is a comment
#    This file is part of DEAP.
#
#    DEAP is free software: you can redistribute it and/or modify
#    it under the terms of the GNU Lesser General Public License as
#    published by the Free Software Foundation, either version 3 of
#    the License, or (at your option) any later version.
#
#    DEAP is distributed in the hope that it will be useful,
#    but WITHOUT ANY WARRANTY; without even the implied warranty of
#    MERCHANTABILITY or FITNESS FOR A PARTICULAR PURPOSE. See the
#    GNU Lesser General Public License for more details.
#
#    You should have received a copy of the GNU Lesser General Public
#    License along with DEAP. If not, see <http://www.gnu.org/licenses/>.



import os,sys
sys.path.insert(0,'C:\\Program Files (x86)\\PTI\\PSSE33\\PSSBIN')
os.environ['PATH'] = 'C:\\Program Files (x86)\\PTI\\PSSE33\\PSSBIN'+';'+os.environ['PATH']
from pylab import *
import LossesPython11
import fitness

from deap import base
from deap import creator
from deap import tools



#-------------- DATA NEEDED TO DEFINE CODIFICATION
creator.create("FitnessMin", base.Fitness, weights=(-1.0,))
creator.create("Individual", list, fitness=creator.FitnessMin)


global buses, x_size

Telemark = 1 # 1 opens Telemark case, 0 opens Vestfold case


if Telemark == 1:
    buses = [14, 17, 19, 20, 21, 27, 30, 31, 32, 33, 34,  42, 400] #[21, 31, 32] #Available buses in Telemark
else:
    buses =  [2, 101, 201, 301, 602, 901, 1217, 1255, 1257, 1273, 1278, 1283, 1390, 1398, 1405, 1408,
    1413, 1415, 1416, 1417, 1418, 1419, 1420, 1424, 1425, 1426, 1427, 1428, 1429, 1436, 1439, 1498,
    1501, 1587, 1593, 1801, 2001, 2101] #Available buses in Vestfold
k=size(buses) #number of AVAILABLE buses
bitspercb = 12 # BITS PER CAPACITOR BANK (CB)
x_size = k * bitspercb #each CB will have 12 bits and each chromosome 12*k
M = pow(2,bitspercb)-1

import random

toolbox = base.Toolbox()
# Attribute generator
```

```
toolbox.register("attr_bool", random.randint, 0, 1)
# Structure initializers
toolbox.register("individual", tools.initRepeat, creator.Individual,
    toolbox.attr_bool, x_size)
toolbox.register("population", tools.initRepeat, list, toolbox.individual)

def d2b(f, b):
    n = int(f)
    base = int(b)
    ret = ""
    for y in range(base-1, -1, -1):
        ret += str((n >> y) & 1)
    return ret

def conversion(indivi,max_power_trans):
    #x_size = int(len(str(indivi)))
    n = bitspercb
    xa =''
    for j in range(x_size):
        xa = xa + str(int(indivi[j]))

    xcbs = [ float(int(xa[j*n : (j+1)*n],2))*max_power_trans[j]/M for j in range(k) ]

    for i in range(len(xcbs)):
        if xcbs[i] < kscb*cb_minimum_size:
            xcbs[i] = 0.
    return xcbs



def evalOneMax(individual):
    individual_c = conversion(individual,max_power_trans) #Converts from binary representation to
    decimal
    return [fitness.fit(individual_c, T, years, KE,KR,KM,Kext,cb_minimum_size, cb_maximum_size, winter,
    Telemark, slope, constraints, buses, max_power_trans, num_transf, nominal_volt, nominal_pf)[0]]

# Operator registering
toolbox.register("evaluate", evalOneMax)
toolbox.register("mate", tools.cxTwoPoints)
toolbox.register("mutate", tools.mutFlipBit, indpb=0.05)
toolbox.register("select", tools.selTournament, tournsize=3)
#toolbox.register("select", tools.selRoulette)

def factor(t,p,n):
    factor = 0
    for i in range(n):
        factor += ((1+p)**i)/((1+t)**i)
    return factor

def main():
    now = datetime.datetime.now() #Time
    print str(now)
    ##########################-DATA-##################### HECTOR
    global cb_minimum_size, cb_maximum_size, cb_maximum_size2, T, KE, KR, KM, Kext, winter,
    Telemark, slope, constraints, nominal_volt, nominal_pf, nom_pf, nom_deltavolt, years, years1, years2,
    years3, max_power_trans, num_transf, kscb
    if Telemark == 1: #Maximum power allowed by transformers
        max_power_trans = [30., 30., 15., 40., 30., 75.75, 30., 15., 15., 30., 15., 30.75, 10.]
        num_transf = [[2, 2, 1, 2, 2, 4, 2, 1, 1, 2, 1, 2, 1 ], [ 15., 15., 15., 20., 15.,  18.9375, 15.,  15., 15.,
        15.,15.,15.375, 10.]]
```

```
    #Nominal voltages for buses from original case in Telemark
    nominal_volt = [0.9864000082015991, 0.9965774416923523, 0.9820456504821777,
    0.9935963749885559, 0.9564775824546814, 0.9553197622299194, 0.9449586272239685,
    0.9449586272239685, 0.9779844880104065, 0.9454360008239746, 0.9484376907348633,
    0.969795286655426, 0.9514490962028503, 0.9534476399421692, 0.9526903033256531,
    0.948431134223938, 0.9451680779457092, 0.9429348111152649, 0.946739137172699,
    0.9481845498085022, 0.9560107588768005, 0.9560999870300293, 0.9476392269134521,
    0.9833024740219116, 0.9833565354347229, 0.948107123374939, 0.9480345845222473,
    0.947547435760498, 0.9469067454338074, 0.9478999972343445, 0.9475882649421692,
    0.956059992313385, 0.9938703179359436, 0.9465696811676025, 0.9484127759933472,
    0.948207676410675, 0.947365403175354, 0.961199164390564, 0.9610193967819214,
    0.9795196056365967, 0.9821054339408875, 0.9920745491981506, 0.9942881464958191, 1.0,
    0.9931477904319763, 0.9938681125640869, 0.9925756454467773, 1.0440583229064941,
    1.0086678266525269, 1.0245585441589355, 1.0248277187347412, 1.032738208770752,
    1.0292413234710693, 1.0298970937728882, 1.0154999494552612, 1.0092004537582397, 1.0,
    1.0189517736434937, 1.056765079498291, 1.059999942779541, 0.9832600951194763,
    0.932507336139679, 0.9296169877052307, 0.9936174154281616, 0.992900013923645,
    0.9922121167182922, 0.9923163056373596, 0.9893938302993774, 0.9460427165031433,
    0.9866999983787537, 0.9901164174079895, 0.9833300113677979, 1.007599949836731,
    0.9444400072097778, 0.9444400072097778, 0.996707558631897]
    nominal_pf = [0.9486832946234875, 0.9821790144404517, 0.9486833038500962,
    0.9506657018801034, 0.9962893617451879, 0.9883086622616891, 0.9919632988868424,
    0.9880249334593876, 0.9912559862184933, 0.9724746311731169, 0.9499899610415863,
    0.9976765629911872, 0.9957795922726442, 0.9985327923576389, 0.9978616105858487,
    0.9988997443289251, 0.996880972941118, 0.9858558458931067, 0.9507749606047069, 1.0,
    6.123031769111886e-17, 0.9948757345555095, 6.123031769111886e-17, 0.99998456825799,
    0.9501238797966282, 0.9520285621287126, 0.9499872732906824, 0.9486832917676322,
    0.9486833038500962, 0.9505216538778778, 0.949925788782497, 0.9510340720635365,
    0.9508714370812013, 0.9497947826324705, 0.9886443956635264, 0.950091809080251,
    0.9524241458810333, 0.9495753205634484, 0.9524241458810333, 0.9500317509596723,
    0.9761870601839527, 0.9500317509596723, 0.9486832953578502]
else:
    max_power_trans = [16., 25., 22.5, 10., 12.5, 12.5, 31.5, 15.75, 25., 8., 25., 8., 22.5, 15.75, 15., 15.,
    20., 31.5, 25., 20., 15., 15.75, 12.5, 22.5, 30., 31.5, 25., 25., 25., 25.75, 15.75, 31.5,  37.5, 25., 20.,
    10., 8., 20.]
    num_transf = [[1, 1, 2, 2, 1, 1, 2, 1, 2, 1, 2, 1, 2, 1, 1, 1, 2, 2, 4, 2, 1, 1, 1, 2, 2, 2, 2, 2, 2, 2, 1, 2, 3, 2,
    2, 2, 2, 2], \
                [ 16., 25.,11.25, 5.,12.5,12.5,15.75,15.75,12.5, 8.,12.5, 8.,11.25,
                15.75,15.,15.,10.,15.75,6.25,10.,15.,15.75,12.5,11.25,15.,15.75,12.5,12.5,12.5,12.875,15.75,15
                .75,12.5,12.5,10.,5.,4., 10.]]
    nominal_volt = [0.9962496161460876, 0.8944634199142456, 0.9680748581886292,
    0.9728454351425171, 0.899463951587677, 0.966580331325531, 0.8976662158966064,
    0.8922545909881592, 0.8957124352455139, 0.9061315655708313, 0.9900145530700684,
    0.9030084609985352, 0.9702364206314087, 0.8968620300292969, 0.9006768465042114, 1.0,
    0.9894052147865295, 0.9749227166175842, 0.9014720916748047, 0.9709425568580627, 1.0,
    0.9972646832466125, 0.9688130617141724, 0.9619632959365845, 0.9933841824531555,
    0.9853055477142334, 0.9594244956970215, 0.9763199687004089, 0.9858558773994446,
    0.9696002006530762, 0.9865742325782776, 0.9747240543365479, 0.9868267774581909,
    0.9753950834274292, 0.9705768823623657, 0.9701027870178223, 0.9708573222160339,
    0.9649279117584229, 0.9593239426612854, 0.9646528363227844, 0.9635495543479919,
    0.9630184769630432, 0.9634543657302856, 0.964869499206543, 0.9603306651115417,
    0.9596023559570312, 0.9644697308540344, 0.9888824224472046, 0.9636656045913696,
    0.971640408039093, 0.9655811190605164, 1.0003968477249146, 1.0, 0.967119574546814,
    0.8990491628646851, 1.0008752346038818, 1.0, 0.9640973210334778, 0.9622787833213806,
    0.8984959721565247, 0.8985216021537781, 0.8962931036949158, 0.8961841464042664]
    nominal_pf = [0.950366715725956, 0.989570214512584, 0.9994127625283334,
    0.9506054569087762, 0.950397131480438, 0.9524241458810333, 0.9942878833962411,
    0.9492535886177365, 0.9991330729776726, 0.9932631396929565, 0.9865275805774509,
    0.950309031986394, 0.9246781020556955, 0.9933596874179859, 0.8750340416176856,
    0.9833821812458453, 0.9492749218114773, 0.7071067811865476, 0.9993034265138183,
```

```
    0.9980321934841888, 0.9925434562753054, 0.9504697366010705, 0.9505306073644221,
    0.9775210452519167, 0.9925706143866178, 0.9942614425566723, 0.9982743733090996,
    0.9945390408505832, 0.9942149980368328, 0.9981270234595921, 0.9941347452354805,
    0.994489027530242, 0.9985910484291765, 0.9486833029146797, 0.9497017175440386,
    0.9946586230806512, 0.9818368969333605, 0.9497356063145225, 0.9837447491577539,
    0.9942653331868008, 0.9496286504502847, 0.9494461988426094, 0.9986614439905438]

if Telemark == 1:
    cb_maximum_size = 75.75 #CB Power in MVAr NOT USED
    cb_maximum_size2 = cb_maximum_size #Modifable parameter NOT USED
    cb_maximum_size20 = cb_maximum_size2 #NOT USED
    kscb0 = 0.5 #Modifable parameter
    kscb1 = 0.4
    kscb = kscb0
else:
    cb_maximum_size = 31.5 #CB Power in MVAr NOT USED
    cb_maximum_size2 = 18. #CB Power in MVAr. Modifable parameter NOT USED
    cb_maximum_size20 = cb_maximum_size2 #NOT USED
    kscb0 = 0.5 #Modifable parameter
    kscb1 = 0.5
    kscb = kscb0
cb_minimum_size = 6. #Power in MVAr
#number_of_steps = 91 #Search space is number_of_steps^k, k = number of capacitors
nom_pf = 0.95
nom_deltavolt = 0.03

winter = 1 # 1 opens winter case, 0 opens summer case
slope = 10e10 #slope of the line that defines the out-of-the-limits costs. It has to be adjusted in
function of the other costs so that it has approximately the same magnitude
constraints = [1., 1., 1.,0, k] #Activate constraints on [Voltages, Power factor, CB positive power]


#----------------NOK costs
T = 3000 #Period of the year in hours
years = 20 #life cycle of the cbs

KE = 0.35 * 1000 # 0.35 NOK/kWh = 350 NOK/MWh Active power
KR = 30. * 1000 #30 NOK per kvar. 30000 NOK per Mvar. From Statnett and from Knut Skagerak
KM = 2000 #Cost maintenance in NOK. Provided by Skagerak
Kext = 500000 #Cost extension of the building and switchgears
t = 0.045 # Discount rate
increment_losses = 0.002
increment_reactivepower = 0.002
increment_fixedcosts = 0.01
years1 = factor(t,increment_losses,years)
years2 = factor(t,increment_reactivepower,years)
years3 = factor(t,increment_fixedcosts,years)
years = [years,years1,years2,years3]

random.seed(64)

#------First population
gn = 0 #Register generation number
gnkscb = 0 #Register generation number
pop = toolbox.population(n=200)

CXPB, MUTPB, NGEN = 0.75, 0.35, 100 #GENETIC ALGORITHM PARAMETERS

#------ Solution without CBs -------------- HECTOR
no_cbs = zeros(k)
```

```
fit2ncb = fitness.fit(no_cbs, T, years, KE,KR,KM,Kext,cb_minimum_size, cb_maximum_size, winter,
Telemark, slope, constraints, buses, max_power_trans, num_transf, nominal_volt, nominal_pf)
print "Solution without CBs"
print "Total cost ", fit2ncb


#----------------------------------------- START OF GA

print("Start of evolution")

# Evaluate the entire population
fitnesses = list(map(toolbox.evaluate, pop))
#fitnesses = transform(fitnesses)
for ind, fit2 in zip(pop, fitnesses):
    ind.fitness.values = fit2
min_f = min(fitnesses)

print("  Evaluated %i individuals" % len(pop))

bests = [] #TO PLOT AT THE END HECTOR
bestscb =[]


# Begin the evolution
for g in range(NGEN):
    print("-- Generation %i --" % g)

    # Select the next generation individuals
    offspring = toolbox.select(pop, len(pop)-1)
    # Clone the selected individuals
    offspring = list(map(toolbox.clone, offspring))

    # Apply crossover and mutation on the offspring
    for child1, child2 in zip(offspring[::2], offspring[1::2]):
        if random.random() < CXPB:
            toolbox.mate(child1, child2)
            del child1.fitness.values
            del child2.fitness.values

    for mutant in offspring:
        if random.random() < MUTPB:
            toolbox.mutate(mutant)
            del mutant.fitness.values

    # Evaluate the individuals with an invalid fitness
    invalid_ind = [ind for ind in offspring if not ind.fitness.valid]
    fitnesses = map(toolbox.evaluate, invalid_ind)
    #fitnesses = transform(fitnesses)
    for ind, fit2 in zip(invalid_ind, fitnesses):
        ind.fitness.values = fit2

    print("Evaluated %i individuals" % len(invalid_ind))

    # The population is entirely replaced by the offspring, (edited) except the best solution
    best_ind = tools.selBest(pop, 1)[0]
    pop = []
    pop.append(best_ind) #Elitism selection HECTOR
    pop[1:] = offspring

    # Gather all the fitnesses in one list and print the stats
```

```
    fits = [ind.fitness.values[0] for ind in pop]
    fits2 = sorted(fits)
    fits2 = fits2[0:100]
    length = len(fits2)
    mean = sum(fits2) / length
    sum2 = sum(x*x for x in fits2)
    std = abs(sum2 / length - mean**2)**0.5


    min_fn = fits2[0] #BEST FITNESS
    bests.append(min(fits)) #TO PLOT AT THE END HECTOR
    if min_fn < min_f: #MODIFICATIONS HECTOR
        min_f = min_fn
        gn = g
        if  g > 28:
            gnkscb += 1
            kscb = kscb1
            cb_maximum_size2 = cb_maximum_size

    print("  Min %s" % min_f)
    print("  Max %s" % fits2[99])
    print("  Avg %s" % mean)
    print("  Std %s" % std)

print("-- End of (successful) evolution --")


##########################-RESULTS OUTPUT######################### HECTOR
if Telemark == 1:
    file1 = open("Telemark Winter Solutions ESGA.txt","a")
    file1.write("\nWinter season \n")
    print "###################Telemark Winter#########################"
else:
    file1 = open("Vestfold Winter Solutions ESGA.txt","a")
    file1.write("\nWinter season \n")
    print "####################Vestfold Winter##########################"

best_ind = tools.selBest(pop, 1)[0]
print("Best individual fitness %s" % (best_ind.fitness.values))
min_cb = conversion(best_ind,max_power_trans)
print "Best individual ", min_cb
print "@ generation number ", gn
Flosses = fitness.fit(min_cb, T, years, KE, KR, KM, Kext, cb_minimum_size, cb_maximum_size, winter,
Telemark, slope, constraints, buses, max_power_trans, num_transf, nominal_volt, nominal_pf)
fitbest = toolbox.evaluate(best_ind)
print "Best individual fitness ", fitbest
now2 = datetime.datetime.now()
print str(now2)
time_elapsed = now2 - now
print "Elapsed time ", time_elapsed

file1.write(str(now2))
file1.write(" \n")
file1.write("Constraints ")
file1.write(str(constraints))
file1.write(" \n")
file1.write("Bits per CB ")
file1.write(str(bitspercb))
file1.write(" \n")
file1.write("Span of time ")
```

```
    file1.write(str(T))
    file1.write(" \n")
    file1.write("The optimum CBC is  = ")
    file1.write(str(min_cb))
    file1.write(" \n")
    file1.write("The minimum cost is ")
    file1.write(str(best_ind.fitness.values))
    file1.write("\n (Total cost, Lossescosts, Reactcosts, Fixedcosts, Investment, Num. AB, Num. CB,
    [Active Losses, ReactiveEx, VoltageCC , Power FactorCC, Range CBsCC]) = ")
    file1.write(str(Flosses))
    file1.write(" \n")
    Flosses = [Flosses[0]/1.e6,
    Flosses[7][0],Flosses[1]/1.e6,Flosses[7][1],Flosses[2]/1.e6,Flosses[4]/1.e6,Flosses[3]/1.e6, Flosses[5],
    Flosses[6],Flosses[7][2:4]]
    file1.write(str(Flosses))
    file1.write(" \n")
    file1.write("At generation  = ")
    file1.write(str(gn))
    file1.write(" \n")
    file1.write(str([NGEN,CXPB,MUTPB,len(pop)]))
    file1.write(" \n")
    file1.write("Cross over probability  = ")
    file1.write(str(CXPB))
    file1.write(" \n")
    file1.write("Mutation probability  = ")
    file1.write(str(MUTPB))
    file1.write(" \n")
    file1.write("Number of generations  = ")
    file1.write(str(NGEN))
    file1.write(" \n")
    file1.write("Population  = ")
    file1.write(str(len(pop)))
    file1.write(" \n")
    file1.write("kscb0  = ")
    file1.write(str(kscb0))
    file1.write(" \n")
    file1.write("kscb1  = ")
    file1.write(str(kscb1))
    file1.write(" \n")
    mean2 = sum(min_cb)/Flosses[6]
    file1.write(str([Flosses[6],Flosses[5],sum(min_cb),maxcb,mean2,mincb,fit2ncb[0]-Flosses[0]]))
    file1.write(" \n \n")

    LossesPython11.constraints_report(nominal_volt, nominal_pf, nom_pf)

    #Ploting data for maximum values for each generation
    figure(3)
    plot(range(NGEN),bests, 'ro')
    axis([0, NGEN, 1e8, 3e8])
    xlabel('Generations')
    ylabel('F(x) Minimum')
    title(r'$F(x)$')
    show()


if __name__ == "__main__":
    main()
```

```
# FITNESS FILE
#! /usr/bin/python

__author__="HMLE"
__date__ ="$14.mai.2013 12:55:53$"

import LossesPython11
from pylab import *

def ext_costs(v, num_transf):
    nrcb = 0
    for cb, i in zip(v, range(len(v))):
        if cb > 0:
            nrcb += floor(cb/num_transf[1][i])+1
    return nrcb


def reac_cost2(RL,KR):
    RL = abs(RL)
    if RL > 20:
        m = int(RL / 5.)
        RL = 5*m
        rl = RL*KR
    else:
        rl = 0
    return rl

def invest_cost(v):
    m = (550000.-70000.)/(25-0.6)
    n = 70000. - 0.6 * m
    cost = 0.
    for cb in v:
        if cb > 0:
            cost += m * cb + n
    return cost


def fit(v, T, years, KE, KR, KM, Kext, cb_minimum_size, cb_max_size, winter, Telemark, slope,
constraints, buses, max_power_trans, num_transf, nominal_volt, nominal_pf):

    n1 = len(v)

    nrcb = ext_costs(v, num_transf) #Counting total number of CBs inside stations
    investment = invest_cost(v) + nrcb * Kext  #Total investment

    ncb = len([x for x in v if x > 0]) #Number of capacitor banks
    fixed_omcb_cost = ncb * KM #fixed maintenance costs in NOK

    #This function returns the array (Active Power losses, Reactive power in bus 100, Voltage constraints
    costs, Power factor constraints costs)
    Flosses = LossesPython11.losses(v,buses,Telemark, slope, cb_minimum_size, max_power_trans,
    constraints, nominal_volt, nominal_pf)

    reactive_bill = reac_cost2(Flosses[1],KR)

    # Minimum number of CBs constraints
    mincb_constraint = 0
    if ncb < constraints[3]:
        mincb_constraint = slope*slope
```

```
    # Maximum number of CBs constraints
    maxcb_constraint = 0
    if ncb > constraints[4]:
        maxcb_constraint = slope*slope

    # Costs in NOK for the objective function in present value
    a = KE * T * years[1] * Flosses[0] #Power losses
    b = years[2] * reactive_bill  #Reactive power charge
    c = years[3] * fixed_omcb_cost  #Maintenance costs

    #----Cost function: Active losses + Reactive power billing + Fixed costs + Investment cost +
    Constraints costs + minimum number of CBs constraint
    r = a +  b + c + investment + constraints[0]*Flosses[2] + constraints[1]*Flosses[3] +
    constraints[2]*Flosses[4]+mincb_constraint+maxcb_constraint


    return [r, a, b, c, investment, ncb, nrcb, Flosses]

#-#-#-#-##-#-#-#-##-#-#-#-#-#-#-#-#-#-#-#-##-#-#-#-#-###-#-#
```

```
# LOSSES. INTERACTION WITH PSSE FILE
# -*- coding: utf-8 -*-

from pylab import *
import psspy
import redirect

def open_winter(Telemark):
    #-------------------------open the file
    if Telemark == 1:
    # File:"C:\Hector\Hector info and documents\Python scripts\TM1flow.py", generated on SUN, MAR
    31 2013  16:31, release 33.03.00
        psspy.case(r"""C:\Users\hmle\Desktop\PSSE\PSSE-models\2012\Telemark 2012.sav""")
        psspy.bsys(0,0,[ 56.0,
        132.],0,[],72,[4,5,6,8,9,10,11,12,13,14,15,16,17,18,19,20,21,22,23,24,25,26,27,30,31,32,33,34,35,36,3
        7,39,40,41,42,48,49,50,51,52,53,54,59,61,62,64,65,66,67,68,69,70,71,73,74,75,76,77,82,
        83,84,85,87,88,89,90,97,201,301,400,401,402],0,[],0,[])
        psspy.bsys(1,0,[ 1.0,
        0.1E+05],0,[],77,[4,5,6,8,9,10,11,12,13,14,15,16,17,18,19,20,21,22,23,24,25,26,27,28,29,30,31,32,33,
        34,35,36,37,39,40,41,42,48,49,50,51,52,53,54,59,61,62,64,65,66,67,68,69,70,71,73,74,75,76,77,81,
        82,83,84,85,87,88,89,90,97,100,201,300,301,400,401,402],0,[],0,[])
    else:
        psspy.case(r"""C:\Users\hmle\Desktop\PSSE\PSSE-models\2012\Vestfold 2012.sav""")
        psspy.bsys(1,0,[ 1.0,
        0.1E+05],0,[],63,[1,2,3,101,102,201,202,301,401,501,601,602,801,901,1201,1202,1212,1213,1214,12
        17,1232,1239,1255,1257,1263,1273,1278,1283,1390,1398,1405,1408,1413,1415,1416,1417,1418,1
        419,1420,1423,1424,1425,1426,1427,1428,1429,1436,1437,1439,1447,1448,1470,1493,1498,1501,
        1513,1523,1587,1593,1801,1901,2001,2101],0,[],0,[])
        psspy.bsys(0,0,[ 1.0,
        0.1E+05],0,[],59,[2,3,101,102,201,202,301,401,501,601,602,801,901,1201,1213,1214,1217,1239,125
        5,1257,1263,1273,1278,1283,1390,1398,1405,1408,1413,1415,1416,1417,1418,1419,1420,1423,14
        24,1425,1426,

        1427,1428,1429,1436,1437,1439,1447,1448,1470,1493,1498,1501,1513,1523,1587,1593,1801,1901
        ,2001,2101],0,[],0,[])



def volt_cost(slope, nominal_volt):
    subId = 1
    busStatusFlag = 1
    paramStrList = ['PU']
    ierr, voltageList = psspy.abusreal(subId, busStatusFlag, paramStrList)
    l = voltageList[0]
    cost = 0
    for v1, v2 in zip(l, nominal_volt):
        if abs(v1-v2) > 0.03:
            cost += abs(v1-v2)*slope
    return cost

def cb_cons(slope,v,cb_minimum_size, max_trpower):
    cost = 0
    for i in range(len(v)):
        if v[i] > 10e-3:
            if v[i] < cb_minimum_size/2:
                cost += v[i]*slope
            elif v[i] < cb_minimum_size:
                cost += (cb_minimum_size-v[i])*slope*slope
            elif v[i] > max_trpower[i]:
                cost += (v[i]-max_trpower[i])*slope*slope
```

```
        elif v[i] < -10e-6:
            cost += (-v[i])*(slope**3)
    return cost

def constraints_report(nominal_volt, nominal_pf, nom_pf):
    subId = 1
    busStatusFlag = 1
    paramStrList = ['PU']
    ierr, voltageList = psspy.abusreal(subId, busStatusFlag, paramStrList)
    paramStrList = ['NUMBER']
    ierr, labellist = psspy.abusint(subId, busStatusFlag, paramStrList)

    paramStrList = ['MVAACT']
    ierr, xarray = psspy.alodbuscplx(0, 1, paramStrList)
    paramStrList = ['NUMBER']
    ierr, xarray2 = psspy.alodbusint(0, 1, paramStrList)
    l = voltageList[0]
    l2 = labellist[0]
    l3 = xarray[0]
    l4 = xarray2[0]

    print "Bus     New Voltage       Old voltage      Danger"
    for v1, v2, la in zip(l, nominal_volt,l2):
        #print la, "    ", v1, "      ", v2,
        if abs(v1-v2) > 0.03:
            print la, "    ", v1, "      ", v2,
            print "1111"
        #else: print "0"

    print "Bus     New PF       Old PF      Danger"
    for pf1, pf2, la in zip(l3, nominal_pf, l4):
            if abs(pf1.real) > 0:
                b = math.atan(pf1.imag/abs(pf1.real))
            else:
                b = math.pi/2
            b = math.cos(b)
            #print  la, "       ", b, "        ", pf2,
            if abs(b-pf2) > 0.1:
                print  la, "       ", b, "        ", pf2,
                print "1111"
            #else: print "0"


def pf_costs(slope, nominal_pf):
    paramStrList = ['MVAACT']
    ierr, xarray = psspy.alodbuscplx(0, 1, paramStrList)
    paramStrList = ['NUMBER']
    ierr, xarray2 = psspy.alodbusint(0, 1, paramStrList)
    l = xarray[0]
    la = xarray2[0]
    powerfactors = []
    cost = 0
    for pf1, pf2, i in zip(l, nominal_pf, la):
        if abs(pf1.real) > 0:
            b = math.atan(pf1.imag/abs(pf1.real))
        else:
            b = math.pi/2
        b = math.cos(b)
        if abs(b-pf2) > 0.2 and b < 0.94:
            cost += abs(b-pf2)*slope
```

```
    return cost

def losses(v, buses, Telemark, slope, cb_minimum_size, max_power_trans, constraints, nominal_volt,
nominal_pf):

    redirect.psse2py()

    psspy.psseinit(2000)
    ierr = psspy.progress_output(islct=6)

    open_winter(Telemark)


    #-------------------------modify the reactive power of the buses

    _i=psspy.getdefaultint()
    i=0

    for x in buses:
        ierr = psspy.load_data_4(x, '2', [1,_i,1,1,1,1], [0.,-v[i],0.,0.,0.,0.])
        i+=1
    #print "Return Modified Load"
    #----------------------load flow

    psspy.fnsl([1, 0, 0, 1, 1, 0, 0, 0])

    #print "Return Flow"
    #------------------get active power losses

    ierr, xarray = psspy.aflowcplx(0, 1, 1, 1, 'PQLOSS')
    a = sum(array(xarray))/2
    #print "Return Active Losses"
    #-------------get bought reactive power

    Telemark_base = 79.98919487
    Vestfold_base = 110.382061914
    ierr, xarray2 = psspy.aflowcplx(0, 1, 3, 1, 'PQ')
    S = sum(array(xarray2))
    Q = S.imag

    if Telemark == 1:
        Q += Vestfold_base
    else:
        Q += Telemark_base

    #-------------Constraints
    #-------VOLTAGE range +/-3%
    voltage_costs = volt_cost(slope, nominal_volt)

    #-------POWER FACTOR > 0.95
    powerfactor_costs = pf_costs(slope, nominal_pf)

    #-------CBS WITH ALLOWED CAPACITY RANGE
    range_cb = cb_cons(slope,v,cb_minimum_size, max_power_trans)

    return [a.real, Q, voltage_costs, powerfactor_costs, range_cb]
```

```
# mu+lambda GA file

#! /usr/bin/python

import os,sys
sys.path.insert(0,'C:\\Program Files (x86)\\PTI\\PSSE33\\PSSBIN')
os.environ['PATH'] = 'C:\\Program Files (x86)\\PTI\\PSSE33\\PSSBIN'+';'+os.environ['PATH']
from pylab import *
import LossesPython11
import fitness
import random
from deap import base
from deap import creator
from deap import tools
from deap import algorithms

__author__="HMLE"
__date__ ="$13.mai.2013 18:16:35$"

if __name__ == "__main__":
    print "Hello World";


def d2b(f, b):
    n = int(f)
    base = int(b)
    ret = ""
    for y in range(base-1, -1, -1):
        ret += str((n >> y) & 1)
    return ret

def conversion(indivi,max_power_trans):
    #x_size = int(len(str(indivi)))
    n = bitspercb
    xa =''
    for j in range(x_size):
        xa = xa + str(int(indivi[j]))

    xcbs = [ float(int(xa[j*n : (j+1)*n],2))*max_power_trans[j]/M for j in range(k) ]

    for i in range(len(xcbs)):
        if xcbs[i] < kscb*cb_minimum_size:
            xcbs[i] = 0.
    return xcbs


def factor(t,p,n):
    factor = 0
    for i in range(n):
        factor += ((1+p)**i)/((1+t)**i)
    return factor

def evalOneMax(individual):
    individual_c = conversion(individual,max_power_trans) #Converts from binary representation to
    decimal
    return [fitness.fit(individual_c, T, years, KE,KR,KM,Kext,cb_minimum_size, cb_maximum_size, winter,
    Telemark, slope, constraints, buses, max_power_trans, num_transf, nominal_volt, nominal_pf)[0]]

def evalOneMax2(individual):
    individual_c = conversion(individual,max_power_trans) #Converts from binary representation to
```

```
    decimal
    return [1/fitness.fit(individual_c, T, years, KE,KR,KM,Kext,cb_minimum_size, cb_maximum_size,
    winter, Telemark, slope, constraints, buses, max_power_trans, num_transf, nominal_volt,
    nominal_pf)[0]]


def main():
    toolbox = base.Toolbox()

    Tournament = 1;

    if Tournament == 1:
        toolbox.register("select", tools.selTournament, tournsize=3)
        toolbox.register("evaluate", evalOneMax)
        creator.create("FitnessMin", base.Fitness, weights=(-1.0,)) #Minimum
    else:
        toolbox.register("select", tools.selRoulette)
        toolbox.register("evaluate", evalOneMax2)
        creator.create("FitnessMin", base.Fitness, weights=(1.0,)) #Maximum
    # Operator registering
    toolbox.register("mate", tools.cxTwoPoints)
    toolbox.register("mutate", tools.mutFlipBit, indpb=0.05)
    #toolbox.register("select", tools.selRoulette)

    #-------------- DATA NEEDED TO DEFINE CODIFICATION
    global buses, x_size, Telemark, bitspercb, k, M

    Telemark = 0 # 1 opens Telemark case, 0 opens Vestfold case


    if Telemark == 1:
        buses = [14, 17, 19, 20, 21, 27, 30, 31, 32, 33, 34,  42, 400] #[21, 31, 32] #Available buses in
        Telemark
    else:
        buses =  [2, 101, 201, 301, 602, 901, 1217, 1255, 1257, 1273, 1278, 1283, 1390, 1398, 1405, 1408,
        1413, 1415, 1416, 1417, 1418, 1419, 1420, 1424, 1425, 1426, 1427, 1428, 1429, 1436, 1439,
        1498, 1501, 1587, 1593, 1801, 2001, 2101] #Available buses in Vestfold
    k=size(buses) #number of AVAILABLE buses
    bitspercb = 12 # BITS PER CAPACITOR BANK (CB)
    x_size = k * bitspercb #each CB will have 12 bits and each chromosome 12*k
    M = pow(2,bitspercb)-1


    creator.create("Individual", list, fitness=creator.FitnessMin)
    # Attribute generator
    toolbox.register("attr_bool", random.randint, 0, 1)
    # Structure initializers
    toolbox.register("individual", tools.initRepeat, creator.Individual,
    toolbox.attr_bool, x_size)
    toolbox.register("population", tools.initRepeat, list, toolbox.individual)


    now = datetime.datetime.now() #Time
    print str(now)
    ##########################-DATA-##################### HECTOR
    global cb_minimum_size, cb_maximum_size, cb_maximum_size2, T, KE, KR, KM, Kext, winter, slope,
    constraints, nominal_volt, nominal_pf, nom_pf, nom_deltavolt, years, years1, years2, years3,
    max_power_trans, num_transf, kscb
    if Telemark == 1: #Maximum power allowed by transformers
        max_power_trans = [30., 30., 15., 40., 30., 75.75, 30., 15., 15., 30., 15., 30.75, 10.]
```

```
    num_transf = [[2, 2, 1, 2, 2, 4, 2, 1, 1, 2, 1, 2, 1 ], [ 15., 15., 15., 20., 15.,  18.9375, 15.,  15., 15.,
    15.,15.,15.375, 10.]]
    #Nominal voltages for buses from original case in Telemark
    nominal_volt = [0.9864000082015991, ... (same data as in ESGA) 0.996707558631897]
    nominal_pf = [0.9486832946234875,...(same data as in ESGA) 0.9486832953578502]
else:
    max_power_trans = [16., 25., 22.5, 10., 12.5, 12.5, 31.5, 15.75, 25., 8., 25., 8., 22.5, 15.75, 15., 15.,
    20., 31.5, 25., 20., 15., 15.75, 12.5, 22.5, 30., 31.5, 25., 25., 25., 25.75, 15.75, 31.5,  37.5, 25., 20.,
    10., 8., 20.]
    num_transf = [[1, 1, 2, 2, 1, 1, 2, 1, 2, 1, 2, 1, 2, 1, 1, 1, 2, 2, 4, 2, 1, 1, 1, 2, 2, 2, 2, 2, 2, 2, 1, 2, 3, 2,
    2, 2, 2, 2], \
             [ 16., 25.,11.25, 5.,12.5,12.5,15.75,15.75,12.5, 8.,12.5, 8.,11.25,
             15.75,15.,15.,10.,15.75,6.25,10.,15.,15.75,12.5,11.25,15.,15.75,12.5,12.5,12.5,12.875,15.75,15
             .75,12.5,12.5,10.,5.,4., 10.]]
    nominal_volt = [0.9962496161460876, ...(same data as in ESGA)
    nominal_pf = [0.950366715725956, ... (same data as in ESGA)

if Telemark == 1:
    cb_maximum_size = 75.75 #CB Power in MVAr NOT USED
    cb_maximum_size2 = cb_maximum_size #Modifable parameter NOT USED
    cb_maximum_size20 = cb_maximum_size2 #NOT USED
    kscb0 = 0.5 #Modifable parameter
    kscb1 = 0.5
    kscb = kscb0
else:
    cb_maximum_size = 31.5 #CB Power in MVAr NOT USED
    cb_maximum_size2 = 18. #CB Power in MVAr. Modifable parameter NOT USED
    cb_maximum_size20 = cb_maximum_size2 #NOT USED
    kscb0 = 0.5 #Modifable parameter
    kscb1 = 0.5
    kscb = kscb0
cb_minimum_size = 6. #Power in MVAr
#number_of_steps = 91 #Search space is number_of_steps^k, k = number of capacitors
nom_pf = 0.95
nom_deltavolt = 0.03
#search_space_size = number_of_steps**k
#sizes = zeros(number_of_steps)
#step = (cb_maximum_size-cb_minimum_size) / (number_of_steps-1)
winter = 1 # 1 opens winter case, 0 opens summer case
slope = 10e10 #slope of the line that defines the out-of-the-limits costs. It has to be adjusted in
function of the other costs so that it has approximately the same magnitude
constraints = [1., 1., 1., 0] #Activate constraints on [Voltages, Power factor, CB positive
power,Minimum number of CBs]


#----------------NOK costs
T = 3000 #Period of the year in hours
years = 20 #life cycle of the cbs
KE = 0.35 * 1000 # 0.35 NOK/kWh = 350 NOK/MWh Active power
KR = 30. * 1000 #30 NOK per kvar. 30000 NOK per Mvar. From Statnett and from Knut Skagerak
KM = 2000 #Cost maintenance in NOK. Provided by Skagerak
Kext = 500000 #Cost extension of the building and switchgears
t = 0.045 # Discount rate
increment_losses = 0.002
increment_reactivepower = 0.002
increment_fixedcosts = 0.01
years1 = factor(t,increment_losses,years)
years2 = factor(t,increment_reactivepower,years)
years3 = factor(t,increment_fixedcosts,years)
years = [years,years1,years2,years3]
```

```
random.seed(64)

#------First population
gn = 0 #Register generation number
gnkscb = 0 #Register generation number
pop = toolbox.population(n=300)
CXPB, MUTPB, NGEN = 0.5, 0.12, 200 #GENETIC ALGORITHM PARAMETERS
mu = 150
lambda_ = 400

#------ Solution without CBs -------------- HECTOR
no_cbs = zeros(k)
fit2ncb = fitness.fit(no_cbs, T, years, KE,KR,KM,Kext,cb_minimum_size, cb_maximum_size, winter,
Telemark, slope, constraints, buses, max_power_trans, num_transf, nominal_volt, nominal_pf)
print "Solution without CBs"
print "Total cost ", fit2ncb

sizes = (0, cb_maximum_size)
ranges = [sizes for i in range(k)]
#ranges = ((0,100),(70,100),(0,100))

print("Start of optimization")


##---------------------OPTIMIZATION PROCEDURE
s = tools.Statistics(n=3)
s.register("Mean", mean)
s.register("Min",min)
s.register("Desv",std)
H = tools.HallOfFame(NGEN)
verbose = 0
pop2 = algorithms.eaMuPlusLambda(pop, toolbox, mu, lambda_, CXPB, MUTPB, NGEN)

#print H
#print s.Min
print("-- End of optmization --")

#Save the best CBC as a PSS\E case

print("-- End of (successful) evolution --")

# Gather all the fitnesses in one list and print the stats
fits = [ind.fitness.values[0] for ind in pop2]
fits2 = sorted(fits)
fits2 = fits2[0:100]
length = len(fits2)
means = sum(fits2) / length
sum2 = sum(x*x for x in fits2)
std2 = abs(sum2 / length - means**2)**0.5

print("  Min %s" % fits2[0])
print("  Max %s" % fits2[-1])
print("  Avg %s" % means)
print("  Std %s" % std2)

fitbest = min(pop)

best_ind = tools.selBest(pop2, 1)[0]
#print("Best individual is %s, %s" % (best_ind, best_ind.fitness.values))
print("Best individual is %s" % (best_ind.fitness.values))
```

```
min_cb = conversion(best_ind,max_power_trans)
print "Best individual ", min_cb
#print "@ generation number ", gn
#Flosses = LossesPython11.losses(min_cb,buses,Telemark, slope, cb_minimum_size,
max_power_trans, constraints, nominal_volt, nominal_pf)
Flosses = fitness.fit(min_cb, T, years, KE, KR, KM, Kext, cb_minimum_size, cb_maximum_size, winter,
Telemark, slope, constraints, buses, max_power_trans, num_transf, nominal_volt, nominal_pf)
fitbest = toolbox.evaluate(best_ind)
print "Best individual fitness ", fitbest
now2 = datetime.datetime.now()
print str(now2)
time_elapsed = now2 - now
print "Elapsed time ", time_elapsed


if Telemark == 1:
    file1 = open("Telemark Winter Solutions.txt","a")
    file1.write("\nWinter season \n")
    print "##################Telemark Winter########################"
else:
    file1 = open("Vestfold Winter Solutions.txt","a")
    file1.write("\nWinter season \n")
    print "###################Vestfold Winter#########################"

file1.write(str(now2))
file1.write(" \n")
file1.write("Constraints ")
file1.write(str(constraints))
file1.write(" \n")
if Tournament == 1:
    file1.write("Tournament\n ")
else:
    file1.write("Roulette \n ")
file1.write("Bits per CB ")
file1.write(str(bitspercb))
file1.write(" \n")
file1.write("Span of time ")
file1.write(str(T))
file1.write(" \n")
file1.write("The optimum CBC is  = ")
file1.write(str(min_cb))
file1.write(" \n")
file1.write(str(best_ind))
file1.write(" \n")
file1.write("The minimum cost is ")
file1.write(str(best_ind.fitness.values))
file1.write("\n (Total cost, Lossescosts, Reactcosts, Fixedcosts, Investment, [Active Losses,
ReactiveEx, VoltageCC , Power FactorCC, Range CBsCC]) = ")
file1.write(str(Flosses))
file1.write(" \n")
file1.write("At generation  = ")
file1.write(str(gn))
file1.write(" \n")
file1.write("Cross over probability  = ")
file1.write(str(CXPB))
file1.write(" \n")
file1.write("Mutation probability  = ")
file1.write(str(MUTPB))
file1.write(" \n")
file1.write("Number of generations  = ")
```

```
    file1.write(str(NGEN))
    file1.write(" \n")
    file1.write("Population  = ")
    file1.write(str(len(pop)))
    file1.write(" \n")
    file1.write("kscb0  = ")
    file1.write(str(kscb0))
    file1.write(" \n")
    file1.write("kscb1  = ")
    file1.write(str(kscb1))
    file1.write(" \n")

    LossesPython11.constraints_report(nominal_volt, nominal_pf, nom_pf)

if __name__ == "__main__":
    main()
```

```
# mu,lambda GA file

#! /usr/bin/python

import os,sys
sys.path.insert(0,'C:\\Program Files (x86)\\PTI\\PSSE33\\PSSBIN')
os.environ['PATH'] = 'C:\\Program Files (x86)\\PTI\\PSSE33\\PSSBIN'+';'+os.environ['PATH']
from pylab import *
import LossesPython11
import fitness

from deap import base
from deap import creator
from deap import tools
from deap import algorithms

__author__="HMLE"
__date__ ="$13.mai.2013 18:16:35$"

if __name__ == "__main__":
    print "Hello World";


#-------------- DATA NEEDED TO DEFINE CODIFICATION
global buses, x_size
Telemark = 1 # 1 opens Telemark case, 0 opens Vestfold case
if Telemark == 1:
    buses = [14, 17, 19, 20, 21, 27, 30, 31, 32, 33, 34,  42, 400] #[21, 31, 32] #Available buses in Telemark
else:
    buses =  [2, 101, 201, 301, 602, 901, 1217, 1255, 1257, 1273, 1278, 1283, 1390, 1398, 1405, 1408,
    1413, 1415, 1416, 1417, 1418, 1419, 1420, 1424, 1425, 1426, 1427, 1428, 1429, 1436, 1439, 1498,
    1501, 1587, 1593, 1801, 2001, 2101] #Available buses in Vestfold
k=size(buses) #number of AVAILABLE buses
bitspercb = 12 # BITS PER CAPACITOR BANK (CB)
x_size = k * bitspercb #each CB will have 12 bits and each chromosome 12*k
M = pow(2,bitspercb)-1

import random


def d2b(f, b):
    n = int(f)
    base = int(b)
    ret = ""
    for y in range(base-1, -1, -1):
        ret += str((n >> y) & 1)
    return ret

def conversion(indivi,max_power_trans):
    #x_size = int(len(str(indivi)))
    n = bitspercb
    xa =''
    for j in range(x_size):
        xa = xa + str(int(indivi[j]))

    xcbs = [ float(int(xa[j*n : (j+1)*n],2))*max_power_trans[j]/M for j in range(k) ]

    for i in range(len(xcbs)):
        if xcbs[i] < kscb*cb_minimum_size:
            xcbs[i] = 0.
```

```
    return xcbs



def factor(t,p,n):
    factor = 0
    for i in range(n):
        factor += ((1+p)**i)/((1+t)**i)
    return factor

def evalOneMax(individual):
    individual_c = conversion(individual,max_power_trans) #Converts from binary representation to
    decimal
    return [fitness.fit(individual_c, T, years, KE,KR,KM,Kext,cb_minimum_size, cb_maximum_size, winter,
    Telemark, slope, constraints, buses, max_power_trans, num_transf, nominal_volt, nominal_pf)[0]]

creator.create("FitnessMin", base.Fitness, weights=(-1.0,))
creator.create("Individual", list, fitness=creator.FitnessMin)

import random

toolbox = base.Toolbox()
# Attribute generator
toolbox.register("attr_bool", random.randint, 0, 1)
# Structure initializers
toolbox.register("individual", tools.initRepeat, creator.Individual,
toolbox.attr_bool, x_size)
toolbox.register("population", tools.initRepeat, list, toolbox.individual)

# Operator registering
toolbox.register("evaluate", evalOneMax)
toolbox.register("mate", tools.cxTwoPoints)
toolbox.register("mutate", tools.mutFlipBit, indpb=0.05)
toolbox.register("select", tools.selTournament, tournsize=3)
#toolbox.register("select", tools.selRoulette)

def main():
    now = datetime.datetime.now() #Time
    print str(now)
    ##########################-DATA-###################### HECTOR
    global cb_minimum_size, cb_maximum_size, cb_maximum_size2, T, KE, KR, KM, Kext, winter,
    Telemark, slope, constraints, nominal_volt, nominal_pf, nom_pf, nom_deltavolt, years, years1, years2,
    years3, max_power_trans, num_transf, kscb
    if Telemark == 1: #Maximum power allowed by transformers
        max_power_trans = [30., 30., 15., 40., 30., 75.75, 30., 15., 15., 30., 15., 30.75, 10.]
        num_transf = [[2, 2, 1, 2, 2, 4, 2, 1, 1, 2, 1, 2, 1 ], [ 15., 15., 15., 20., 15.,  18.9375, 15.,  15., 15.,
        15.,15.,15.375, 10.]]
        #Nominal voltages for buses from original case in Telemark
        nominal_volt = [0.9864000082015991, same data as in ESGA  0.996707558631897]
        nominal_pf = [0.9486832946234875,same data as in ESGA 0.9486832953578502]
    else:
        max_power_trans = [16., 25., 22.5, 10., 12.5, 12.5, 31.5, 15.75, 25., 8., 25., 8., 22.5, 15.75, 15., 15.,
        20., 31.5, 25., 20., 15., 15.75, 12.5, 22.5, 30., 31.5, 25., 25., 25., 25.75, 15.75, 31.5,  37.5, 25., 20.,
        10., 8., 20.]
        num_transf = [[1, 1, 2, 2, 1, 1, 2, 1, 2, 1, 2, 1, 2, 1, 1, 1, 2, 2, 4, 2, 1, 1, 1, 2, 2, 2, 2, 2, 2, 2, 1, 2, 3, 2,
        2, 2, 2, 2], \
                    [ 16., 25.,11.25, 5.,12.5,12.5,15.75,15.75,12.5, 8.,12.5, 8.,11.25,
                    15.75,15.,15.,10.,15.75,6.25,10.,15.,15.75,12.5,11.25,15.,15.75,12.5,12.5,12.5,12.875,15.75,15
                    .75,12.5,12.5,10.,5.,4., 10.]]
        nominal_volt = [0.9962496161460876, same data as in ESGA, 0.8961841464042664]
```

```
    nominal_pf = [0.950366715725956, same data as in ESGA 0.9986614439905438]

if Telemark == 1:
    cb_maximum_size = 75.75 #CB Power in MVAr NOT USED
    cb_maximum_size2 = cb_maximum_size #Modifable parameter NOT USED
    cb_maximum_size20 = cb_maximum_size2 #NOT USED
    kscb0 = 0.5 #Modifable parameter
    kscb1 = 0.5
    kscb = kscb0
else:
    cb_maximum_size = 31.5 #CB Power in MVAr NOT USED
    cb_maximum_size2 = 18. #CB Power in MVAr. Modifable parameter NOT USED
    cb_maximum_size20 = cb_maximum_size2 #NOT USED
    kscb0 = 0.5 #Modifable parameter
    kscb1 = 0.5
    kscb = kscb0
cb_minimum_size = 6. #Power in MVAr
#number_of_steps = 91 #Search space is number_of_steps^k, k = number of capacitors
nom_pf = 0.95
nom_deltavolt = 0.03
#search_space_size = number_of_steps**k
#sizes = zeros(number_of_steps)
#step = (cb_maximum_size-cb_minimum_size) / (number_of_steps-1)
winter = 1 # 1 opens winter case, 0 opens summer case
slope = 10e10 #slope of the line that defines the out-of-the-limits costs. It has to be adjusted in
function of the other costs so that it has approximately the same magnitude
constraints = [1., 1., 1., 0] #Activate constraints on [Voltages, Power factor, CB positive
power,Minimum number of CBs]


#----------------NOK costs
T = 3000 #Period of the year in hours
years = 20 #life cycle of the cbs
KE = 0.35 * 1000 # 0.35 NOK/kWh = 350 NOK/MWh Active power
KR = 30. * 1000 #30 NOK per kvar. 30000 NOK per Mvar. From Statnett and from Knut Skagerak
KM = 2000 #Cost maintenance in NOK. Provided by Skagerak
Kext = 500000 #Cost extension of the building and switchgears
t = 0.045 # Discount rate
increment_losses = 0.002
increment_reactivepower = 0.002
increment_fixedcosts = 0.01
years1 = factor(t,increment_losses,years)
years2 = factor(t,increment_reactivepower,years)
years3 = factor(t,increment_fixedcosts,years)
years = [years,years1,years2,years3]
random.seed(64)

#------First population
gn = 0 #Register generation number
gnkscb = 0 #Register generation number
pop = toolbox.population(n=300)
CXPB, MUTPB, NGEN = 0.6, 0.35, 150 #GENETIC ALGORITHM PARAMETERS
mu = 200
lambda_ = 300

#------ Solution without CBs -------------- HECTOR
no_cbs = zeros(k)
fit2ncb = fitness.fit(no_cbs, T, years, KE,KR,KM,Kext,cb_minimum_size, cb_maximum_size, winter,
Telemark, slope, constraints, buses, max_power_trans, num_transf, nominal_volt, nominal_pf)
print "Solution without CBs"
```

```
print "Total cost ", fit2ncb

sizes = (0, cb_maximum_size)
ranges = [sizes for i in range(k)]
#ranges = ((0,100),(70,100),(0,100))

print("Start of optimization")


##--------------------OPTIMIZATION PROCEDURE
s = tools.Statistics(n=3)
s.register("Mean", mean)
s.register("Min",min)
s.register("Desv",std)
H = tools.HallOfFame(NGEN)
verbose = 0
pop2 = algorithms.eaMuCommaLambda(pop, toolbox, mu, lambda_, CXPB, MUTPB, NGEN)

#print H
#print s.Min
print("-- End of optmization --")

#Save the best CBC as a PSS\E case

print("-- End of (successful) evolution --")

#Save the best CBC as a PSS\E case
# Gather all the fitnesses in one list and print the stats
fits = [ind.fitness.values[0] for ind in pop2]
fits2 = sorted(fits)
fits2 = fits2[0:100]
length = len(fits2)
means = sum(fits2) / length
sum2 = sum(x*x for x in fits2)
std2 = abs(sum2 / length - means**2)**0.5

print("  Min %s" % fits2[0])
print("  Max %s" % fits2[-1])
print("  Avg %s" % means)
print("  Std %s" % std2)

############################-RESULTS-######################### HECTOR
#if gnkscb < 2:
#  print "H----------------------"
#  kscb = kscb0
#  cb_maximum_size2 = cb_maximum_size20
print kscb

fitbest = min(pop)

best_ind = tools.selBest(pop2, 1)[0]
#print("Best individual is %s, %s" % (best_ind, best_ind.fitness.values))
print("Best individual is %s" % (best_ind.fitness.values))
min_cb = conversion(best_ind,max_power_trans)
print "Best individual ", min_cb
#print "@ generation number ", gn
#Flosses = LossesPython11.losses(min_cb,buses,Telemark, slope, cb_minimum_size,
max_power_trans, constraints, nominal_volt, nominal_pf)
Flosses = fitness.fit(min_cb, T, years, KE, KR, KM, Kext, cb_minimum_size, cb_maximum_size, winter,
Telemark, slope, constraints, buses, max_power_trans, num_transf, nominal_volt, nominal_pf)
```

```
fitbest = toolbox.evaluate(best_ind)
print "Best individual fitness ", fitbest
now2 = datetime.datetime.now()
print str(now2)
time_elapsed = now2 - now
print "Elapsed time ", time_elapsed


if Telemark == 1:
    file1 = open("Telemark Winter Solutions.txt","a")
    file1.write("\nWinter season \n")
    print "##################Telemark Winter#####################"
else:
    file1 = open("Vestfold Winter Solutions.txt","a")
    file1.write("\nWinter season \n")
    print "###################Vestfold Winter#########################"

file1.write(str(now2))
file1.write(" \n")
file1.write("Constraints ")
file1.write(str(constraints))
file1.write(" \n")
file1.write("Bits per CB ")
file1.write(str(bitspercb))
file1.write(" \n")
file1.write("Span of time ")
file1.write(str(T))
file1.write(" \n")
file1.write("The optimum CBC is  = ")
file1.write(str(min_cb))
file1.write(" \n")
file1.write(str(best_ind))
file1.write(" \n")
file1.write("The minimum cost is ")
file1.write(str(best_ind.fitness.values))
file1.write("\n (Total cost, Lossescosts, Reactcosts, Fixedcosts, Investment, [Active Losses,
ReactiveEx, VoltageCC , Power FactorCC, Range CBsCC]) = ")
file1.write(str(Flosses))
file1.write(" \n")
file1.write("At generation  = ")
file1.write(str(gn))
file1.write(" \n")
file1.write("Cross over probability  = ")
file1.write(str(CXPB))
file1.write(" \n")
file1.write("Mutation probability  = ")
file1.write(str(MUTPB))
file1.write(" \n")
file1.write("Number of generations  = ")
file1.write(str(NGEN))
file1.write(" \n")
file1.write("Population  = ")
file1.write(str(len(pop)))
file1.write(" \n")
file1.write("kscb0  = ")
file1.write(str(kscb0))
file1.write(" \n")
file1.write("kscb1  = ")
file1.write(str(kscb1))
file1.write(" \n")
```

```
    LossesPython11.constraints_report(nominal_volt, nominal_pf, nom_pf)

if __name__ == "__main__":
    main()
```

Appendix C

ESGA Output

013-06-02 19:56:14.523000

SIEMENS POWER TECHNOLOGIES INTERNATIONAL

2000 BUS POWER SYSTEM SIMULATOR–PSS(R)E-33.3.0

INITIATED ON SUN, JUN 02 2013 19:56

Solution without CBs

Total cost 320840522.25993979, Losses cost 242096633.47526574, RP cost 78743888.78467405, Investment 0.0, Maintenance 0.0, Power losses 16.690042715961823 MW, Reactive exch. 190.37125678399514 Mvar,

Start of evolution Evaluated 200 individuals – Generation 0 – Evaluated 164 individuals Min 255528507.94 Max 3.12164142651e+21 Avg 1.10136785571e+20 Std 4.91594755067e+20 – Generation 1 – Evaluated 161 individuals Min 255176231.369 Max 27726094395.6 Avg 10194439677.1 Std 12248569442.3 – Generation 2 – Evaluated 158 individuals Min 254763197.947 Max 282130267.56 Avg 267465814.497 Std 9543633.30398 – Generation 3 – Evaluated 170 individuals Min 254366042.183 Max 265540111.564 Avg 258605650.577 Std 4030427.59263 – Generation 4 – Evaluated 168 individuals Min 254246477.813 Max 256422727.336 Avg 255438014.867 Std 516849.30237 – Generation 5 – Evaluated 170 individuals Min 253901981.011 Max 255965041.041 Avg 255110957.203 Std 469569.288544 – Generation 6 – Evaluated 180 individuals Min 253845754.335 Max 255606215.292 Avg 254879451.091 Std 474347.720146 – Generation 7 – Evaluated 153 individuals Min 253657276.818 Max 255282617.675 Avg 254503726.62 Std 415430.342676 – Generation 8 – Evaluated 170 individuals Min 253631067.785 Max 254941956.781 Avg 254237433.397 Std 359027.74392 – Generation 9 – Evaluated 166 individuals Min 253415662.448 Max 254474003.284 Avg 253939965.863 Std 218530.758622 – Generation 10 – Evaluated 164 individuals Min 252941852.822 Max 254476694.017 Avg 253842561.935 Std 260754.304647 – Generation 11 – Evaluated 168 individuals Min 252941852.822

Max 254450642.024 Avg 253773618.078 Std 270061.760744 – Generation 12 – Evaluated 169 individuals Min 252941852.822 Max 253944418.679 Avg 253624107.695 Std 195767.143985 – Generation 13 – Evaluated 162 individuals Min 252941852.822 Max 253699956.656 Avg 253467751.157 Std 208729.698261 – Generation 14 – Evaluated 172 individuals Min 252941852.822 Max 253656751.413 Avg 253396676.11 Std 227789.27023 – Generation 15 – Evaluated 163 individuals Min 252917928.75 Max 253575861.966 Avg 253252787.218 Std 228697.021738 – Generation 16 – Evaluated 165 individuals Min 252917928.75 Max 253553313.4 Avg 253062769.298 Std 148014.501776 – Generation 17 – Evaluated 165 individuals Min 252912017.388 Max 253128624.467 Avg 252985963.004 Std 58935.3671746 – Generation 18 – Evaluated 156 individuals Min 252850114.449 Max 253728688.399 Avg 252980100.211 Std 111194.102434 – Generation 19 – Evaluated 158 individuals Min 252844001.958 Max 252984451.9 Avg 252937681.944 Std 20534.9273191 – Generation 20 – Evaluated 169 individuals Min 252844001.958 Max 253102216.667 Avg 252953677.872 Std 49688.4293976 – Generation 21 – Evaluated 174 individuals Min 252844001.958 Max 253044972.314 Avg 252940563.312 Std 35540.305795 – Generation 22 – Evaluated 168 individuals Min 252844001.958 Max 253098010.145 Avg 252936287.353 Std 45177.5699214 – Generation 23 – Evaluated 169 individuals Min 252814436.459 Max 253013527.29 Avg 252919890.998 Std 34009.0404452 – Generation 24 – Evaluated 171 individuals Min 252814436.459 Max 253043201.746 Avg 252919098.58 Std 41559.6085641 – Generation 25 – Evaluated 159 individuals Min 252814436.459 Max 253004084.081 Avg 252908692.345 Std 38293.7533287 – Generation 26 – Evaluated 175 individuals Min 252814436.459 Max 253170100.3 Avg 252914052.835 Std 58466.6594907 – Generation 27 – Evaluated 160 individuals Min 252814436.459 Max 252959652.287 Avg 252887261.294 Std 32371.9939454 – Generation 28 – Evaluated 175 individuals Min 252814436.459 Max 253649020.976 Avg 252935249.831 Std 195190.819415 – Generation 29 – Evaluated 179 individuals Min 252814436.459 Max 253170053.462 Avg 252882267.125 Std 73037.7593851 – Generation 30 – Evaluated 160 individuals Min 252814436.459 Max 252862509.289 Avg 252844254.287 Std 7427.97576733 – Generation 31 – Evaluated 164 individuals Min 252814436.459 Max 252845696.552 Avg 252842100.45 Std 5840.28629435 – Generation 32 – Evaluated 172 individuals Min 252814436.459 Max 252844165.366 Avg 252842466.532 Std 4069.26725591 – Generation 33 – Evaluated 175 individuals Min 252814436.459 Max 252844001.958 Avg 252842351.371 Std 2894.21630152 – Generation 34 – Evaluated 155 individuals Min 252814436.459 Max 252842586.221 Avg 252841843.748 Std 3916.75886416 – Generation 35 – Evaluated 155 individuals Min 252814436.459 Max 252842418.288 Avg 252841794.673 Std 3910.58358816 – Generation 36 – Evaluated 168 individuals Min 252814436.459 Max 252842468.302 Avg 252841671.064 Std 3951.27118786 – Generation 37 – Evaluated 154 individuals Min 252814436.459 Max 252844814.833 Avg 252841470.762 Std 4837.46875959 – Generation 38 – Evaluated 171 individuals Min 252814061.244 Max 252878322.445 Avg 252842217.048 Std 9125.76177642 – Generation 39 – Evaluated 152 individuals Min 252814061.244 Max 295564624873.0 Avg 141182647949.0 Std 141412127241.0 – Generation 40 – Evaluated 165 individuals Min 252814061.244 Max 295564358904.0 Avg 178634388316.0 Std 134611741847.0 – Generation 41 – Evaluated 149 individuals Min 252814061.244 Max 283839427607.0 Avg 114080593936.0 Std 128612721803.0 – Generation 42 – Evaluated 155 individuals Min 252814061.244 Max 254536201626.0 Avg 50835155724.7 Std 98413367482.5 – Generation 43 – Evaluated 167 individuals Min 252814061.244 Max 242090385260.0 Avg 3356432895.36 Std 24463291390.3 – Generation 44 – Evaluated 165 individuals Min 252814061.244 Max 254525998.184 Avg 253648177.943 Std 419751.799272 – Generation 45 – Evaluated 164 individuals Min 252814061.244 Max 254359213.275 Avg 253521306.957 Std 407214.250635 – Generation 46 – Evaluated 175 individuals Min 252814048.702 Max 253782542.062 Avg 253315862.933 Std 311978.107104 – Generation 47 – Evaluated 168 individuals Min 252774242.504 Max 253712861.589 Avg 253191230.366 Std 258284.73519 – Generation 48 – Evaluated 169 individuals Min 252341780.842 Max 253581673.6 Avg 253045675.283 Std 198431.680636 – Generation 49 – Evaluated 166 individuals Min 252341780.842 Max 253174461.56 Avg 252932076.48 Std 144998.672463 – Generation 50 – Evaluated 168 individuals Min 252280601.087 Max 253822699.386 Avg 252954899.727 Std 257092.348809 – Generation 51 – Evaluated 168 individuals Min 252280601.087

Max 253772766.672 Avg 252945916.643 Std 326196.586101 – Generation 52 – Evaluated 154 individuals Min 252280291.746 Max 253272834.833 Avg 252807740.79 Std 239687.094338 – Generation 53 – Evaluated 176 individuals Min 252257643.202 Max 253205658.42 Avg 252703764.847 Std 260535.629364 – Generation 54 – Evaluated 161 individuals Min 252257643.202 Max 252958227.013 Avg 252558867.76 Std 250086.404812 – Generation 55 – Evaluated 175 individuals Min 252257643.202 Max 252831155.305 Avg 252420640.132 Std 203635.604235 – Generation 56 – Evaluated 172 individuals Min 252249831.007 Max 252342058.604 Avg 252293519.718 Std 22136.860482 – Generation 57 – Evaluated 169 individuals Min 252241843.748 Max 252342058.604 Avg 252288591.815 Std 22608.6238414 – Generation 58 – Evaluated 158 individuals Min 252241350.554 Max 252314100.987 Avg 252280403.654 Std 19180.7545211 – Generation 59 – Evaluated 169 individuals Min 252240381.738 Max 252314084.109 Avg 252275157.694 Std 17469.3869383 – Generation 60 – Evaluated 164 individuals Min 252240167.482 Max 252291940.837 Avg 252265946.095 Std 15203.619569 – Generation 61 – Evaluated 170 individuals Min 252239290.79 Max 252287918.68 Avg 252259493.148 Std 14554.0556547 – Generation 62 – Evaluated 170 individuals Min 252238921.314 Max 252269547.557 Avg 252247970.107 Std 7020.68030892 – Generation 63 – Evaluated 159 individuals Min 252234499.918 Max 252251457.114 Avg 252242474.422 Std 3881.47600791 – Generation 64 – Evaluated 172 individuals Min 252234499.918 Max 252241350.554 Avg 252239728.722 Std 945.08412324 – Generation 65 – Evaluated 165 individuals Min 252233484.702 Max 252240381.738 Avg 252238968.559 Std 1325.33769282 – Generation 66 – Evaluated 178 individuals Min 252233250.45 Max 252239290.79 Avg 252238019.78 Std 1864.03218856 – Generation 67 – Evaluated 174 individuals Min 252232952.439 Max 252238921.314 Avg 252236549.194 Std 2126.18907908 – Generation 68 – Evaluated 171 individuals Min 252231988.857 Max 252237833.207 Avg 252234924.061 Std 2013.0633373 – Generation 69 – Evaluated 159 individuals Min 252231988.857 Max 252233484.702 Avg 252233160.596 Std 441.941172556 – Generation 70 – Evaluated 165 individuals Min 252230848.994 Max 252233473.586 Avg 252232874.662 Std 509.572369738 – Generation 71 – Evaluated 177 individuals Min 252230848.994 Max 252233250.45 Avg 252232404.315 Std 492.641857743 – Generation 72 – Evaluated 168 individuals Min 252230697.616 Max 252232489.045 Avg 252232034.727 Std 443.377942618 – Generation 73 – Evaluated 170 individuals Min 252230337.907 Max 252232282.174 Avg 252231715.232 Std 483.884283688 – Generation 74 – Evaluated 174 individuals Min 252229707.599 Max 252231988.857 Avg 252231370.583 Std 701.786292257 – Generation 75 – Evaluated 177 individuals Min 252229200.056 Max 252231988.857 Avg 252230918.98 Std 774.927093345 – Generation 76 – Evaluated 169 individuals Min 252229200.056 Max 252231771.101 Avg 252230317.786 Std 488.868080365 – Generation 77 – Evaluated 170 individuals Min 252228481.828 Max 252230697.616 Avg 252229860.453 Std 373.930474821 – Generation 78 – Evaluated 159 individuals Min 252227240.088 Max 252229707.599 Avg 252229546.701 Std 373.630833845 – Generation 79 – Evaluated 176 individuals Min 252227240.088 Max 252229707.599 Avg 252229367.431 Std 583.266662857 – Generation 80 – Evaluated 179 individuals Min 252226738.915 Max 252229707.599 Avg 252229163.15 Std 688.679896614 – Generation 81 – Evaluated 153 individuals Min 252225804.132 Max 252229707.599 Avg 252228618.142 Std 936.692051851 – Generation 82 – Evaluated 163 individuals Min 252225036.649 Max 252229200.056 Avg 252227884.273 Std 1063.65783972 – Generation 83 – Evaluated 161 individuals Min 252225036.649 Max 252229200.056 Avg 252227309.61 Std 1063.39080304 – Generation 84 – Evaluated 169 individuals Min 252225036.649 Max 252228265.451 Avg 252226554.89 Std 824.795732288 – Generation 85 – Evaluated 166 individuals Min 252225036.649 Max 252227240.088 Avg 252226055.02 Std 617.031603729 – Generation 86 – Evaluated 167 individuals Min 252225036.649 Max 252227240.088 Avg 252225865.511 Std 519.307230837 – Generation 87 – Evaluated 181 individuals Min 252225036.649 Max 252227490.031 Avg 252225714.87 Std 494.279273286 – Generation 88 – Evaluated 175 individuals Min 252225036.649 Max 252225804.132 Avg 252225458.341 Std 299.91998933 – Generation 89 – Evaluated 176 individuals Min 252225036.649 Max 252225544.338 Avg 252225162.215 Std 213.653925777 – Generation 90 – Evaluated 169 individuals Min 252225036.649 Max 252225036.649 Avg 252225036.649 Std 8.94427191 – Generation 91 – Evaluated 171 individuals Min 252225036.649

Max 252225036.649 Avg 252225036.649 Std 8.94427191 – Generation 92 – Evaluated 177 individuals Min 252225036.649 Max 252225036.649 Avg 252225036.649 Std 8.94427191 – Generation 93 – Evaluated 177 individuals Min 252225036.649 Max 252225036.649 Avg 252225036.649 Std 8.94427191 – Generation 94 – Evaluated 166 individuals Min 252225036.649 Max 252225036.649 Avg 252225036.649 Std 8.94427191 – Generation 95 – Evaluated 170 individuals Min 252224628.504 Max 252225036.649 Avg 252225032.568 Std 39.6988664826 – Generation 96 – Evaluated 183 individuals Min 252224494.696 Max 252225036.649 Avg 252225014.904 Std 95.1209756048 – Generation 97 – Evaluated 168 individuals Min 252223908.066 Max 252225036.649 Avg 252224966.455 Std 193.059576297 – Generation 98 – Evaluated 171 individuals Min 252223908.066 Max 252225036.649 Avg 252224859.849 Std 287.429991476 – Generation 99 – Evaluated 155 individuals Min 252223908.066 Max 252225036.649 Avg 252224608.588 Std 361.618583593 – End of (successful) evolution –

Best individual fitness 252223908.066 Best individual [27.435271128480704, 28.138739618954567, 0.0, 37.51831949193942, 11.519296531509527, 54.915974596971175, 14.904738641914998, 0.0, 0.0, 29.985344406448462, 14.890083048363458, 0.0, 0.0] @ generation number 97 Best individual fitness [252223908.06609872] 2013-06-02 19:58:22.715000 Elapsed time 0:02:08.192000

Appendix D

Skagerak Nett transmission networks

Table D.1: Available buses with load in Telemark.

Transmission substations	Winter loads	
	MW	Mvar
BREVIK 132,00	50.5	12.1
FROGNER 132,00	36.3	5.6
HAUEN 132,00	21.3	1
HOVHOLT 132,00	30.8	4.1
KJØRBEKK 132,00	24	1.9
KLYVE 132,00	22.9	1.5
LANGESUND 132,00	28.9	9.5
MOFLATA 132,00	18	-0.1
MYRENE 132,00	36.5	5.7
ROLIGHETEN 132,00	92.2	5
SKOTFOSS 132,00	13.5	4.4
VOLL 132,00	8.4	2.8
ÅRHUS 132,00	40	6.8

Table D.2: Maximum sizes of CBs at each station and number of transformers at each station in Telemark.

Available bus	Name	Base kV	Max. Mvar	Num. Transformers	Mvar/Trans.
1	FROGNER	132	30.00	2	15.00
2	MYRENE	132	30.00	2	15.00
3	HOVHOLT	132	15.00	1	15.00
4	BREVIK	132	40.00	2	20.00
5	LANGESUND	132	30.00	2	15.00
6	ROLIGHETEN	132	75.75	4	18.94
7	KLYVE	132	30.00	2	15.00
8	HAUEN	132	15.00	1	15.00
9	KJØRBEKK	132	15.00	1	15.00
10	ÅRHUS	132	30.00	2	15.00
11	SKOTFOSS	132	15.00	1	15.00
12	MOFLATA B	132	30.75	2	15.38
13	VOLL	132	10.00	1	10.00

Table D.3: Available buses with loads in Vestfold

Transmission substations	Winter loads	
	MW	Mvar
ASKEHAUG 66,000	17.7	-1.9
BENTSRUD 130,00	34.2	4.2
BERGELØKKA 130,00	31	1.9
BRUNLA 130,00	20.7	-1.1
BRåR 66,000	16.8	5.5
BUGÅRDEN 130,00	23.9	2.6
DOLVEN 130,00	9.3	3.1
ESSO 130,00	15.3	5
FIRING 130,00	15.5	-1.9
GJÆRDAL 130,00	36.1	3.9
GOKSTAD 130,00	35.4	4.1
HASLESTAD 66,000	11	3.6
HEIMDAL 66,000	41.4	-8
HOLMESTRAND 130,00	24.1	0.9
HOLTAN 130,00	17.5	-0.6
KALDNES 130,00	37.8	6.9
KULLERØD 66,000	16.6	5.5
KVELDE 130,00	4.7	-2.6
LEINÅS 130,00	6	-6
LOFSTAD 130,00	5.1	-2.1
MO 130,00	33.2	3.5
NES 130,00	18	-2.1
RAKKÅS 130,00	15.8	-2.3
RANVIK 130,00	39.8	6.6
RØNNINGEN 130,00	16	5.3
RØREÅSEN 130,00	28.8	1.2
SANDE 130,00	19.1	-1.2
SEMB 66,000	12.4	4.1
SLAGEN 130,00	15.3	-3.3
SLAGEN 66 66,000	10	3.3
SNIPPEN 130,00	15.3	0.9
STANGEBY 130,00	31.8	3.3
SUNDLAND 130,00	34.4	3.7
SVELVIK 130,00	19.5	3.6
TROLLDALEN 130,00	21.1	6.9
UNDERSBO 130,00	32.4	3.4
VEGGBAKKEN 66,000	25.1	1.3
VINDAL 130,00	15.8	-1.7

Table D.4: Maximum sizes of CBs at each station and number of transformers at each station in Vestfold.

Available bus	Name	Base kV	Max. Mvar	Num. Transformers	Mvar/Trans.
1	BRåR	66	16.00	1	16.00
2	RAKKÅS	130	25.00	1	25.00
3	HOLTAN	130	22.50	2	11.25
4	HASLESTAD	66	10.00	2	5.00
5	ASKEHAUG	66	12.50	1	12.50
6	KULLERØD	66	12.50	1	12.50
7	RØREÅSEN	130	31.50	2	15.75
8	NES	130	15.75	1	15.75
9	RANVIK	130	25.00	2	12.50
10	LOFSTAD	130	8.00	1	8.00
11	GOKSTAD	130	25.00	2	12.50
12	KVELDE	130	8.00	1	8.00
13	SVELVIK	130	22.50	2	11.25
14	RØNNINGEN	130	15.75	1	15.75
15	LEINÅS	130	15.00	1	15.00
16	HOLMESTRAND	130	15.00	1	15.00
17	SANDE	130	20.00	2	10.00
18	BENTSRUD	130	31.50	2	15.75
19	TROLLDALEN	130	25.00	4	6.25
20	ESSO	130	20.00	2	10.00
21	SLAGEN	130	15.00	1	15.00
22	FIRING	130	15.75	1	15.75
23	VINDAL	130	12.50	1	12.50
24	SNIPPEN	130	22.50	2	11.25
25	UNDERSBO	130	30.00	2	15.00
26	GJÆRDAL	130	31.50	2	15.75
27	BERGELØKKA	130	25.00	2	12.50
28	BUGÅRDEN	130	25.00	2	12.50
29	MO	130	25.00	2	12.50
30	BRUNLA	130	25.75	2	12.88
31	DOLVEN	130	15.75	1	15.75
32	STANGEBY	130	31.50	2	15.75
33	HEIMDAL	66	37.50	3	12.50
34	KALDNES	130	25.00	2	12.50
35	SUNDLAND	130	20.00	2	10.00
36	SLAGEN 66	66	10.00	2	5.00
37	SEMB	66	8.00	2	4.00
38	VEGGBAKKEN	66	20.00	2	10.00

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