Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Information Technology and Electrical Engineering
Department of Electric Power Engineering

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A Method for Planning a Fast Charging Station

Applied to the distribution grid of Eidsiva Nett

Master's thesis in Energy and Environmental Engineering
Supervisor: Gerd Kjølle
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Problem description

The electrification of the transport sector will require much from the power grid in the following years, as it introduces large loads with new load profiles. The grid operators will have an important role in how fast the electrification of the transport sector can happen since a secure and predictable charging network will be crucial. There is a lack of planning methods for the future power grid, that can result in wrong dimensioned components in the grid. Over-dimensioned components are not socioeconomically beneficial, while an under-dimensioned grid probably will slow down the electrification.

This master thesis will aim to find a method for planning a fast charging station. It will be discussed which factors will be most relevant to consider for such a large load and how that will introduce a new way of thinking when planning the grid.

Which battery and charging technologies that are expected to come in the following years, will be decisive for the requirements of a fast charging station for electric vehicles and freight transport. Different solutions for covering the increased power demand will be discussed in this thesis. In addition to traditional reinforcement of the grid, a large battery at the charging station or avoiding an investment by applying smart power management will be investigated.

The developed method will be applied to some locations in the area of Eidsiva Nett to find an optimal location for a fast charging station and to test the method. It will be performed technical and economic analysis in Netbas for the different alternatives and locations. The factors of interest will be available power, cost of electric power losses and cost of grid investments to avoid overloaded components. There will also be a discussion of the security of supply and the aspects that cannot be measured economically.

Abstract

This master thesis presents a suggestion for a planning method for fast charging stations. A new way of thinking when planning new, large connections in the grid will be necessary for the future distribution grid to be socioeconomic beneficial. Cooperation between the owner of the charging station and the distribution system operator will be crucial to obtain a better utilization of the existing power grid. The need for establishing new load profiles, especially one for fast charging stations was found to be important, as the peak load of a fast charging station occurs during the summer while the existing load profiles are calculated with a peak load in the winter. Besides, a large load such as a fast charging station will require a finer resolution in the load variation in the grid simulation software than it is today. Based on traffic counting, one can see that there is a significant difference between the traffic on a Monday evening compared to a Friday evening. The same applies for the weekends, when there is a lot more traffic on the road on Sunday evenings than Saturday evenings. One cannot always select a location based on the available capacity in the grid, since the location does also need to be a logical place to stop, have some necessary facilities and enough space to establish a charging station.

There is a need for a standard for the requirements of the security of supply, removing that question from the planning process and making the charging stations more predictable for the end-users. This thesis has looked at different alternatives in addition to traditional reinforcements of the grid to cover the increased power demand from a fast charging station. A solution with a battery without any grid upgrades can be beneficial if the total price of the battery system is low enough, it can also be a good temporal solution if the power demand is expected to increase further in the following years. A solution that combines reinforcements of the grid and a smaller battery will probably not be that beneficial, as the price difference between upgrading two different cross-sections is not very large compared to the installation cost. Both the solutions with a battery in the grid will require a lot from the battery, which will be very costly with many charging cycles during the year for this application. The batteries need to have enough storage capacity to cover the demand in all the hours it shall be used, and it requires large enough power capacity to recharge in the possible hours. The second alternative to traditional reinforcement is smart power management which utilizes the existing grid to the maximum. Such a solution will reduce the power to the charging station in the busiest hours of the year, according to the simulation done in this thesis. There may be exceptions somewhere in the grid, making that alternative worth to consider, as it will be the most economically beneficial alternative if the supplied power can be tolerable. Technical and economic analysis for different alternatives and locations have been performed in this thesis, where the alternative with traditional reinforcement was the best alternative for all locations, given that the total price of a battery system is higher than 1030 kr/kW.

Sammendrag

Denne masteroppgaven foreslår en ny planleggingsmetodikk for hurtigladestasjoner. Ny tenking når man skal planlegge nye, store laster i nettet vil være nødvendig for at framtidens distribusjonsnett skal være samfunnsøkonmisk lønnsomt. Samarbeid mellom nettselskap og den som skal eie ladestasjonen vil være avgjørende for å utnytte strømnettet på en best mulig måte. Det er et behov for nye lastporfiler, spesielt for en hurtigladestasjon, da det ble funnet at topplasten for en hurtigladestasjon inntreffer om sommeren, i motsetning til om vinteren som er standard i dagens lastprofiler. I tillegg ble det funnet nødvendig å ha en finere oppløsning på lastvariasjonene i nettsimuleringsprogram enn det som finnes i dag. Basert på data fra trafikktelling er det stor forksjell på trafikken en mandag ettermiddag og en fredag ettermiddag. Det samme gjelder for helgen, da det er mye mer trafikk på veien søndag kveld enn lørdag kveld. Man kan ikke alltid velge lokasjon basert på tilgjengelig kapasitet i nettet, da lokasjonen må være et logisk sted å stoppe, samt ha noen grunnleggende fasiliteter og nok plass til å etablere ladestasjonen. Det bør fastsettes en standard for kravene til leveringspålitelighet, noe som vil fjerne denne vurderingen fra planlegginsprosessen samt gjøre ladestasjonen mer forutsigbar for sluttbrukerne. Det ble i denne oppgaven sett på ulike alternativer i tillegg til tradisjonell reinvestering i nettet for å dekke det økte kapasitetsbehoved fra en hurtigladestasjon. En løsning med batteri i nettet uten andre oppgraderinger vil være lønnsom så lenge totalprisen for batterisystemet er lav nok. Det kan også være en bra midlertidig løsning dersom det er forventet en lastøkning i de kommende årene. En løsning som kombinerer oppgradering av nettet med et mindre batteri vil ikke være like lønnsomt, da prisforskjellen mellom ulike ledningstverrsnitt ikke er så stor i forhold til installasjonskostnaden. Begge løsningene med batterier i nettet vil kreve mye fra batteriet, noe som blir veldig kostbart siden det vil være mange ladesykluser i løpet av et år for dette bruksområdet. Batteriet må ha stor nok lagringskapasitet til å dekke forbruket i de timene det skal brukes, samt stor nok effektkapasitet til å lades opp igjen i de timene det er mulig. Det andre alternativet til tradisjonell reinvestering er smart effektstyring der det eksisterende nettet blir maksimalt utnyttet. Denne løsningen vil redusere effekten til ladestasjonen i de travleste timene i året, ifølge simuleringer gjort i denne oppgaven. Det kan være unntak for visse lokasjoner i nettet, noe som gjør dette alternativet verdt å undersøke, siden det vil være det mest samfunnsøkonomisk lønnsomme alternativet så lenge den leverte effekten er akseptabel. Det har blitt utført tekniske og økonomiske analyser for ulike alternativer og lokasjoner i denne oppgaven, der alternativet med tradisjonell reinvestering var det beste alterativet for alle lokasjonene, så lenge totalprisen for batterisystemet er høyere enn 1030 kr/kW.

Preface

This thesis is written during the spring semester 2019 at the Department of Electric Power Engineering at the Norwegian University of Science and Technology and completes the degree Master of Science in the study program Energy and Environmental Engineering. The thesis is written in cooperation with the research program CINELDI and Eidsiva Nett and focuses on a planning method for a fast charging station. It has been interesting to work on a future-oriented topic where most people have an opinion. Lack of data for the future charging needs and technology have been challenging during this process, but it has allowed me to find creative solutions.

I want to thank my supervisor Gerd Kjølle at SINTEF Energy research for the suggestions and helpful advice during the process of writing this thesis. The cooperation with Eidsiva Nett has been decisive for the final product, as they have shared their data and knowledge with me. I am incredibly grateful for all the interesting discussions and support from Ingrid Nytun Christie, and I would also like to thank Anders Dalseg in Eidsiva Nett for helping me understand Netbas and how to interpret the results.

The five years as a student at NTNU would never have been the same without my fellow students, your company have been highly appreciated.

Nathalie Skyttermoen
Trondheim June 3, 2019

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Abbreviations

BEV Battery Electric Vehicle

CCS Combined Charging System

CENS Cost of Energy Not Supplied

CHAdeMO Charge de Move

DSO Distribution System Operator

Elbilforeningen The Norwegian society for owners of electric vehicles

EV Electric Vehicle

KSU Power system review (Kraftsystemutredning)

NTP The Norwegian National Transport plan 2018-2029

NVE The Norwegian Water Resources and Energy Directorate

OED The Norwegian Ministry of Petroleum and Energy

SoC State of Charge

TSO Transmission System Operator

TØI The Norwegian Institute of Transport Economics

VAT Value Added Tax

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Chapter 1

Introduction

1.1 Motivation

Grid planning has been very predictable the last 40-50 years, as the most present reason to dimension for an incremented load has been a forecast increment in the population. The power grid consisted of some large producers at a high grid level and many small consumers on the lowest grid level. The available power has been almost constant from year to year, even from hour to hour for some of the most stable power sources. The load consumed by the end-users has also been very stable, with one power peak in the morning and another one after work hours in the evening. With more distributed generation from renewable, more unstable energy sources on lower grid levels and a change in consumption due to the electrification of many sectors will require a change from the traditional grid planning. Microgrids and bidirectional power flow will require new planning methods to avoid failures and interruptions in the grid, and a secure electricity supply will be more important as more sectors are getting electrified. One of the sectors that are going through an electrification process is the transport sector and will require much power and much grid capacity. The Norwegian Government has stated some goals for the transport sector in The Norwegian National Transport plan 2018-2029 (NTP) that applies both for passenger cars, where the electrification of the fleet is going fast, and for freight transport and buses. The aim is that a large share of these vehicles shall be emission-free within a few years, which will affect the power grids in a different way than what is seen today. In the project work *Impact on the Distribution Grid of Eidsiva Nett due to Home Charging of Electric Vehicles* [46], the consequences of home charging of Electric Vehicles (EVs) is treated. This thesis will focus on public fast charging of EVs and heavier vehicle types. Freight transport is a sector that in a large scale competes against other countries to do the job, which makes it essential for Norway to have an efficient freight transport, both when it comes to costs and emissions.

DNV GL wrote a report for The Norwegian Ministry of Petroleum and Energy (OED) [37], discussing the different aspects when considering whether it is possible to introduce hydrogen as an energy source in Norway or not. This thesis will focus on electricity as the source of energy, but the factors will be the same. The first and maybe the most decisive factor is the availability of vehicles, which means that the production of vehicle covers the demand. More and more EV models are on the market, but there is a waiting list for the delivery on most of them [24] [56].

Another factor is the energy density and efficiency, where a Battery Electric Vehicle (BEV) has a very low energy density compared to hydrogen and fossil vehicles, resulting in a smaller payload [43]. The efficiency, on the other hand, is best for BEVs compared to the other technologies. How the different systems will be affected by temperature variations may be decisive for some areas, as if cold ambient temperatures reduce the efficiency of the engine or the battery charging.

The infrastructure for tanking or charging of the vehicle will have an important role. If there is a lack of charging points, it will not be practically feasible to drive that kind of vehicle. Also, the time it takes to refill the vehicle will be crucial, as time is money for the consumers in most occasions.

1.2 Structure of the report

This report will first present relevant background information that can be useful to understand the task in this thesis, followed by the required theory to perform the analysis. A suggested method for planning a fast charging station will be developed and later utilized for some locations in the grid of Eidsiva Nett. There will be performed grid analysis for different alternatives for a fast charging station in each of the locations. Some of the options consist of traditional reinforcements of the grid, some include the use of a battery in the grid, or to avoid upgrading the grid at all by applying a smart power management system. It will be performed simplified economic calculations for the different alternatives, where the results will show if there is one of the alternatives that typically is the best for all locations. The report will also comment on what is the main challenges and what types of data is the most crucial to have before considering a location.

1.3 Limitations

As the transport sector includes a lot of different vehicles with different outlooks and very different needs from the power grid, there are some limitations to this thesis. This thesis will focus on public fast charging of the segment of the transport sector driving on the roads, which includes passenger vehicles, vans, local buses and trucks. The grid to be

investigated will be the distribution grid of Eidsiva Nett, where the alternative locations for the charging station will be close to E6. The grid to be analyzed will be from the regional grid transformer to the charging station, which is taught to be connected to the high voltage distribution grid. The grid analysis will only focus on overloaded components and electric power losses. There will be looked at alternatives, including batteries in the grid, but the specific requirements of the batteries will not be found. It will only be assumed that the desired battery exists and what the total price of it needs to be price competitive to other alternatives. The same yields for the smart power management; It is expected to exist and operate in the desired way.

Chapter 2

Background

2.1 Climate goals and political incentives

The goals in NTP is due to the requirements in the Paris agreement to reach the 2 degrees target [12]. This agreement commits all nations in the world to make a plan to reduce global warming due to emission of greenhouse gases. As the transport sector have a large potential for reducing emissions, the Norwegian Government has made some goals and guidelines on how to do that. NTP therefore, states that all new passenger cars and city buses sold after 2025 shall be zero-emission vehicles. The same applies to all vans, 75% of all local buses and 50% of heavier freight transport vehicles sold after 2030

There are several economic incentives for buying a zero-emission vehicle in Norway today. Exemption from registration tax, low annual road tax, free municipal parking, exemption from 25% Value Added Tax (VAT) on purchase and no charges on toll roads [46]. As the share of EVs is becoming a large share of the total vehicle stock in Norway, some of the incentives will be removed, both for practical and economic reasons. The Norwegian Government has stated that there will be a discount on the toll stations for climate-friendly vehicles, equivalent to at least 50% of the amount for conventional vehicles. The Norwegian society for owners of electric vehicles (Elbilforeningen) recommend that the toll prices shall increase gradually corresponding to the total share of EVs in the actual area [28], saying that the toll price for an EV will be 25% of the price for a conventional car when the share is 25%. From 2017, each municipality was free to decide whether the EVs should pay for parking or not [31]. Therefore it is different rules around the country, but the trend is that everyone has to pay for parking in the biggest cities, where the share of EVs is largest. The exemption from the VAT on purchase is the most crucial incentive for the high EV-sales in Norway, 60% answered in a survey done by Elbilforeningen that this was the decisive factor [30]. This incentive is granted at least to the end of 2020, but the Government says that they will continue with the lower tax for EV-purchase as long as necessary to reach

the goals in NTP [30].

2.2 Fast charging of Electric vehicles

Home charging is by now the most present charging location for EVs, wherein average 62% are charging at home every day [46]. The charging routines may change in the future, due to longer travels with an EV and lack of possibilities for home charging, especially for those who live in large apartment buildings and housing cooperatives. The development and forecast of fast charging stations will be discussed here, while the technical aspects will be treated in the theory chapter. To anticipate the charging need in a specific area is hard due to the unknown factors such as how many vehicles there will be in that particular area and when they will charge. To find a model for the needs of public fast charging contains even more unknown factors. One of the reason is that the fast chargers will be used by the traffic through an area, which means that there will be a mismatch between the number of EVs registered in the area and the number of EVs that will charge in the area. Figure 2.1 shows a map of the fast charger coverage in the different counties in Norway based on the expected need in 2025.

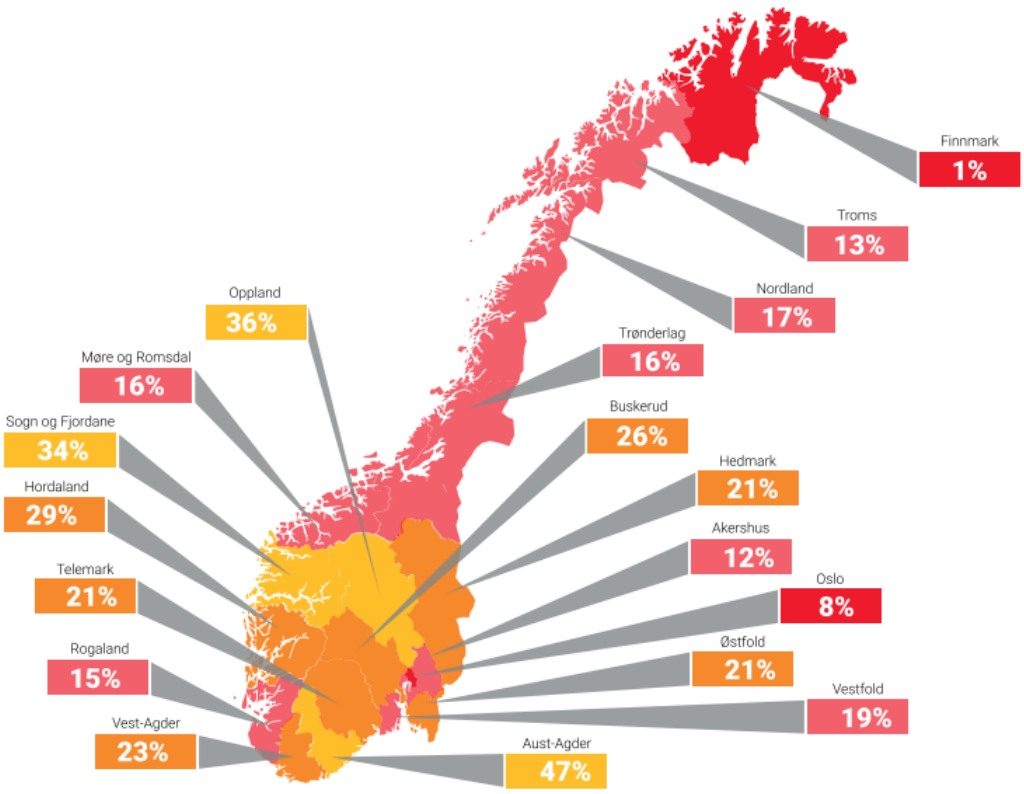

Figure 2.1: Fast charger coverage in the different counties in Norway. Figure from [27]

In the area of Eidsiva Nett, the share of EVs is low compared to for example Oslo [29], which means that one needs to take into account the national EV-share when calculating the need for fast chargers, not only the local share. From Figure 2.1, it looks like the coverage of fast charging points is pretty good in Oppland with 36% coverage compared to Oslo with only 8% [27]. The traffic flow may be completely different in for example holidays when a huge part of the inhabitants of Oslo drives through Oppland to get to ski resorts. Therefore, one cannot only consider the population close to the charging station but also gain knowledge about who will use the chargers. As the holidays will make the charging stations most busy, it means that one will have a dilemma between installing too many charging points that will be unused most of the year or to have enough to cover the peak hour a regular day during the year. Fortum, which operates many of the fast charging points in Norway, announced in June 2018 that they were increasing the price on 35 out of 1350 charging stations that are located in rural areas with little use compared to other points [13]. The reason is that the price of having that much power available makes it unprofitable when the charger is barely used for a large part of the year.

In February 2019 it was registered 1700 fast charging points in Norway, where 231 of them are in Hedmark and Oppland [27]. Elbilforeningen had a survey for their members about fast charging, where 66% of the respondents answered that they were using fast chargers and that 86% of them have experienced a queue at the charging stations. Today it is approximately 118 EVs sharing each charger, giving a need of 8000 new charging points before 2025 to cover the requirements with the same relationship between the number of vehicles and charging points.

There are several types of charges characterized as fast chargers in Norway today. The most common available charging power for fast charging today is 50 kW [11], while the Tesla chargers have a power of 120 kW [54]. The first charger with 150 kW available opened in April 2018 in Ås [26], and other locations have followed with the same power rating since then. The installations are prepared for charging powers up to 350 kW, but this will not be necessary for the first years, as most of the older EV-models cannot utilize charging powers over 50 kW since the battery capacity is too small and they are not constructed to handle such a large power [53]. Hyundai has released the model Hyundai Kona that can charge with a power of 100 kW [16] and Porsche Taycan will be released in 2019 with the possibility of charging with 350 kW [44]. There are two different charging standards in addition to the Tesla chargers; CCS and CHAdeMO. On charging stations with power less than 50 kW, the EV owners need to bring the charging cable that follows the car. Therefore it does not matter which of the standards the vehicle supports. On the charging stations with a power above 50 kW, one needs to use the mounted cable, due to the high current that requires special cables. It is normal that each charging point has two outlets, one for CCS and one for CHAdeMO, where one can only use one of them at the same time. IONITY has introduced a charging network over a large part of Europe that can handle charging powers

up to 350 kW. IONITY is a cooperation of some of the largest European car manufacturers, including the BMW Group, Daimler AG, Ford Motor Company, and Volkswagen Group with Audi and Porsche. All the manufacturers are utilizing the CCS standard, which means that this charging points will only be available for the CCS technology [19]. The most sold EV-model in Norway, Nissan Leaf has the CHAdeMO standard, which makes it interesting to see how the future planning of charging stations will be. It looks like CCS is becoming the European standard, which may force Nissan to change from CHAdeMO to CCS, at least for the European market to avoid a situation where there are not chargers for their vehicles [4]. Figure 2.2 shows the three different charging plug standards. The CHAdeMO which fits among others Nissan Leaf to the left, Tesla that only supports Tesla in the middle and CCS which is the only available in the IONITY charging network to the right.

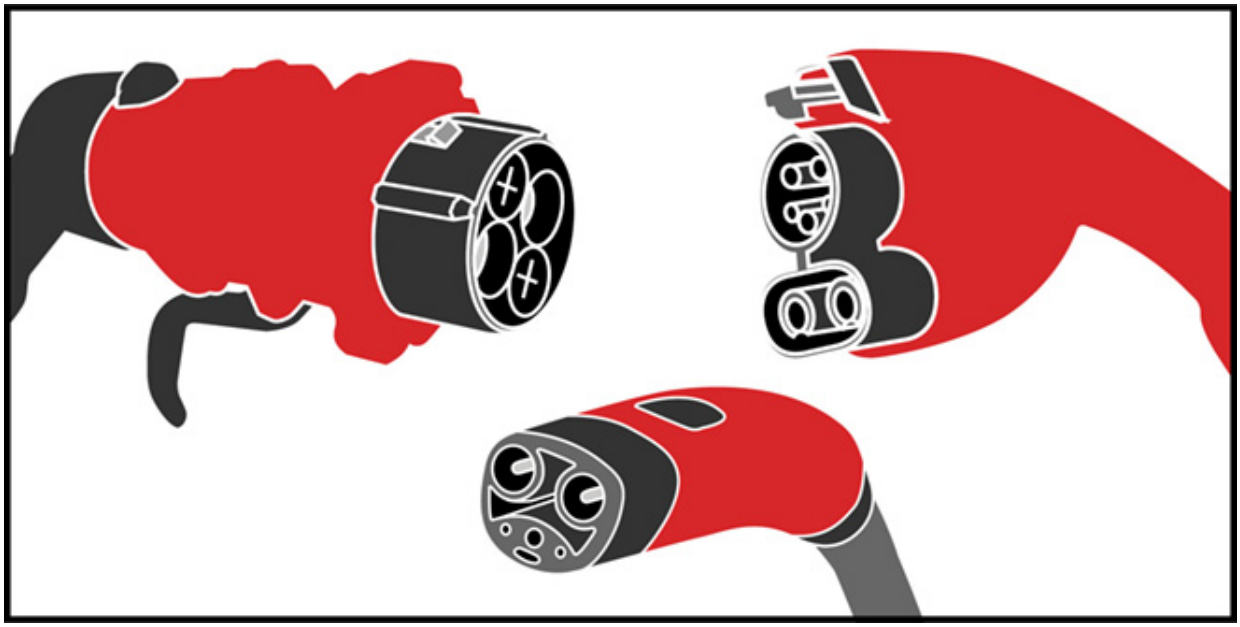

Figure 2.2: The three different charging standards. From the left: CHAdeMO, Tesla and CCS. Figure from [1]

The governmental institution, Enova, has since 2015 given financial support to fast chargers along the main roads in Norway; at least two fast chargers of 50 kW every 50 km [10]. After giving support to 230 fast chargers along the main roads, Enova has now introduced a new support program to cover the needs for fast chargers in each region as an incentive to reach the goal about the EV sale in NTP [9]. They will do it in geographical order, starting with the northern part of Norway, as they see the potential for EV growth most present in that area. Elbilforeningen have made a report where they suggest that it should be charging stations consisting of 50 fast chargers with a power of at least 150 kW

every 150 km along the main roads in Norway [27]. This suggestion corresponds to at least 7.5 MW at each charging station, where Elbilforeningen recommends dimensioning for 10 MW.

2.3 Development on heavier vehicles

Even though the trend for the development of passenger cars is that everything is getting electric, there are still a lot of questions and uncertainties regarding heavier vehicles. The main reason why the development is going slower here is the payload of the vehicles, which is important, as the payload more or less decides the revenue. It yields to find the balance between the capacity of the battery and the size of it, where large capacity gives a large range, but less payload. The status of those questions and some qualified forecasts will be briefly discussed here.

2.3.1 Electric vans

While the EV sales for passenger cars were 20% in 2017, it was only 2.7% for light goods vehicles, which means vans and trucks with a payload less than 3.5 tons. The vehicle itself does not differ that much from passenger cars, but the carrying capacity of a van needs in most cases to be larger than for transporting passengers, giving a larger total weight and more energy used for each kilometre driven. Another point is that the car is the primary working tool, which means that a vehicle limiting the work cannot be accepted. The range may also be more crucial if the job requires flexibility when it comes to changed plans and driving routes. The Norwegian Institute of Transport Economics (TØI) made a report in 2017, where they were looking at the potential for electrification of those vehicle types [14]. The report says that if the development in the electric vans is following the same path, the electric van sales will be 22% in 2030, giving a total share of 16% of all vans that year. If all lighter vans sold after 2025 are electric, the total share will be 60% in 2030. From the project thesis, it was found that if all passenger cars sold after 2025 are electric, the stock in 2030 will only be 50% [46]. The reason why the vehicle fleet is changing faster for the vans is simply that the average lifetime for a van is shorter than for a passenger car. It was found that 50% of all vans used for goods distribution today is five years or newer, while only 4% is older than 15 years [14]. When it came to the potential for electrification, the report had a conclusion saying that all vehicles that daily drive less than 80 km can be replaced by an electric van today, corresponding to 41% of the fleet. If the battery capacity and then the range increases to 130 km, 68% of the vehicles can be replaced.

2.3.2 Electric buses

One can divide the bus fragment into local buses and city buses. The local buses will need a capacity to drive a long distance without recharging the battery too often, and the payload, i.e. the number of passengers, will be crucial for how beneficial the bus will be. The charging of this type of bus will probably be depot charging on a charging station and will depend from that the battery capacity is good. According to the law, the driver has to take 45 minutes to rest every 4.5 hours drive [48]. This means that this time can be used for fast charging of the bus, requiring that there is a charging possibility every 4.5 hours along the route. This will require additional services at the charging station, such as a restaurant or cafeteria. It does not exist zero-emission local buses on the market in Norway today, but it is expected to come within the year [42]. As there are no buses available today, it is more unclear what will be the leading technology. One can assume that all will be electric, all driven on hydrogen, or more probably a mix between the two.

2.3.3 Electric freight transport

By now, only a few full-electric trucks are driving on the Norwegian roads, all of them remodelled trucks that originally had combustion engines. ASKO introduced the first remodelled, electric truck in Norway, with a payload of 5.5 tons, which is 2.5 tons less than before the remodelling. The battery capacity is 200 kWh, giving a range of 200km [51]. There will be launched several battery-electric models the following years from manufactures as Renault and Volvo. The trucks are expected to have a driving range of 200-300 km and be up to 26 tons. Tesla will launch a model, Tesla Semi, which is expected to be 36 tonnes and have a range of 800 km [60]. The restrictions for resting time is the same for a truck driver as for a bus driver; they need to have a 45 minutes break for every 4.5 hours they drive. The distance from Gothenburg in Sweden to Trondheim is 781 km and is estimated to take 9 hours and 51 minutes according to Google Maps. This means that with a battery capacity that gives a range of 800 km, one can drive from Gothenburg to Trondheim with no need for recharging, even if the driver needs to stop twice to rest. If the price is reduced and the payload increases at the same time, electric trucks may be a good alternative in a few years.

THEMA Consulting Group has estimated the development of the price for electric trucks compared to other fuels for the situation in 2020 and 2030. They found that the annual vehicle price for an electric truck will be the double compared to a diesel truck in 2020, but the total cost over one year will be cheaper for an electric truck due to lower operation costs. This is because electricity is less expensive than diesel, lower maintenance costs and exemption from toll. The battery price is expected to be further reduced, while the diesel price and road taxes will increase, making an electric truck even more beneficial

in 2030. As the taxes on the fuel and the electricity price is the reason why electric is the cheapest, it means that the politic in the following years will be decisive for the development of electric freight transport.

A project called ELinGO looked at the possibilities of electrifying the road itself, with three different options. The first is to install an electric rail in the road. The second is an overhead line over the road while the third is inductive charging where all the infrastructure is buried under the road [39]. The project finds that the two first alternatives are those where the technology is almost ready for installation and that it might be a good alternative compared to that the battery needs to last all the distance. All the solutions will be very costly and require much new infrastructure on a large part of the road. The overhead line will also require that the vehicles have approximately the same height, which may not be an optimal situation. Moreover, when the requirements for resting time forces the driver to stop, it may be more beneficial to use that time to recharge the vehicle instead of doing it along the road.

2.4 Charging of heavier electric vehicles

As time is money for freight transport, it means that it will not be possible to wait one hour for an available charger or that the charger provides less power than it is supposed to do. A charging network for freight transport will always require enough charging points and available capacity. The Tesla Semi with a battery capacity of 800 kWh will need a massive charging power to avoid long charging times. As the truck is said to be able to charge around 650 km range in 30 minutes, it will require a charging power of 1.6 MW [3]. If that will be the standard for all truck charging points, it will have a significant impact on the grid. It might be reasonable to think that the average charging power for trucks will not be that high, but between 500 kW and 1 MW is probable. It may be that freight transport, the vans and the local buses will use the same charging standards as passenger cars, giving possibilities to have a joint location for a charging station for all vehicles.

There will be transportation companies that have depots along the road, and therefore will have a charging station for their vehicles at that specific location. This location will probably not be the best possibility for the grid, and it will require that the company pays a larger part of the grid investment cost. Those charging points will, therefore, be reserved for that specific company, giving that there will be a lot of smaller charging station along the road compared to if everyone is charging on the same network. In the same time, it will generate less traffic on the public charging stations and then possibilities to reduce the capacity at those.

2.5 Important traffic routes in the area of Eidsiva Nett

For the traffic from Oslo to Trondheim, the natural way is to drive through the area of Eidsiva Nett. E6 goes through the area from Stange in the south to Dombås in the north, a distance of 212 km. Another option is Rv3 through Østerdalen, which is nearly 300 km in the area of Eidsiva Nett. This means that if the transport sector is electrified in Norway, the charging infrastructure in the area of Eidsiva Nett is essential. The area of the regional grid of Eidsiva Nett is the area inside the black line on the map in Figure 2.3, where the two main roads, E6 and Rv3 are marked in green and blue. E6 is going through Gudbrandsdalen via Brummunddal and Lillehammer while Rv3 is going through Østerdalen via Elverum and Koppang.

Figure 2.3: The grid area of Eidsiva Nett is inside the black line on the map. E6 through Gudbrandsdalen is marked in green and Rv3 through Østerdalen in blue

As one can see on Figure 2.3, a large part of E6 from Oslo to Trondheim goes through the area where Eidsiva Nett owns and operates the regional grid. Eidsiva Nett is responsible for the distribution grid from Hamar to Lillehammer. The other road alternative, Rv3, is inside the regional grid area from Stange in the south to almost Røros in the north. The distribution grid area covers Rv3 from Hamar to Koppang.

Chapter 3

Theory

3.1 Construction of the Norwegian power grid

The power grid is constructed by power lines and cables, and it will always be electric power losses due to the physical construction of the conductor. To avoid large power losses when the power is transported a long distance, the Norwegian power grid is divided into three grid levels. The transmission grid has a nominal voltage of 300 kV or 420 kV and is operated by Statnett as the Transmission System Operator (TSO). The regional grid has a voltage level of 66 kV or 132 kV and is together with the distribution grid with a voltage level below 22 kV operated by the 130 different Distribution System Operators (DSOs) in Norway [35]. Both the regional grid and the distribution grid are defined as distribution systems by the EU.

3.2 Capacity in the grid

The transformers have different lines out that are sharing the total capacity from the transformer. There are some grid customers that are a part of an agreement where the grid operator can disconnect the power supply in order to cover the demand for other customers in the grid during a fault (utkoblbar tariff). The DSO will reconnect the customer when the grid is repaired, giving them a lower cost of being connected [7]. This flexibility is essential to have a reliable power supply and can also postpone reinvestments in the grid. The capacity in each of the radials is given by the dimensions of the power lines, fuses and switches. It may, therefore, be possible to increase the power flow in one line by increasing the sizing, as long as the total power from all the lines does not exceed the power rating of the transformer. All the power in a radial needs to go through the first cable from the transformer, which means that this cable will need the largest cross-section, it may still be bottlenecks further out in the grid, if the dimensions are reduced more than the power

flow is, especially with new connections.

The capacity of the transformer itself is given in KVA and can be calculated by Equation 3.1.

$$S_n = \sqrt{3} \cdot U_n \cdot I_n \tag{3.1}$$

where:

S = Nominal power [KVA]
V = Nominal voltage [kV]
I = Nominal current [A]

The transformer will be overloaded if the current through it gets too high, which results in a reduced lifetime of the transformer. The lifetime of the transformer depends on the insulation, where a higher current corresponds to a higher load level and a higher temperature in the transformers, which reduces the lifetime. The cooling of the insulation depends on the ambient temperature, which means that lower ambient temperatures increase the overloading capacity [5]. A transformer can be overloaded by 20% for a number of hours during the year, and even higher for shorter time spans [6].

The transmission grid and the regional grid are, in most cases constructed to fulfil the N-1 criteria, which means that the system shall be able to handle a failure in one component without violating the power quality. This means that the current needs to flow in another direction without causing any overloads, or affecting the voltage quality. This criterion is somewhat used in the distribution grid too, but it is not seen as beneficial as the outage costs usually are lower than the investment costs to fulfil the criteria. Consequently, many transformer stations and power lines seem to be over-dimensioned, which they are until a failure occurs. Therefore a grid planner needs to take this criterion under consideration when checking the available capacity at one point or are dimensioning for a new grid connection. This means that if one transformer with a capacity of 20 MVA is loaded only 50%, it may not be correct to say that there is 10 MVA available capacity from this transformer, as it may be a capacity reserve for another transformer station.

3.3 Traditional planning methods for power grids

The main reasons for investments in the distribution grid are new investments due to new consumption followed by reinvestments due to the technical condition of the existing grid and reinvestment due to new consumption [34]. New consumption is, for example, if there are established new houses or new industry somewhere, requiring a power supply that was not available at that point before. The DSO may experience that there are locations in the grid where there are higher losses and more frequent failures than others, which indicated that the grid does not fulfil the technical requirements and makes reinvestments necessary.

The traditional method for investments in the distribution grid is shown in the flow chart in Figure 3.1.

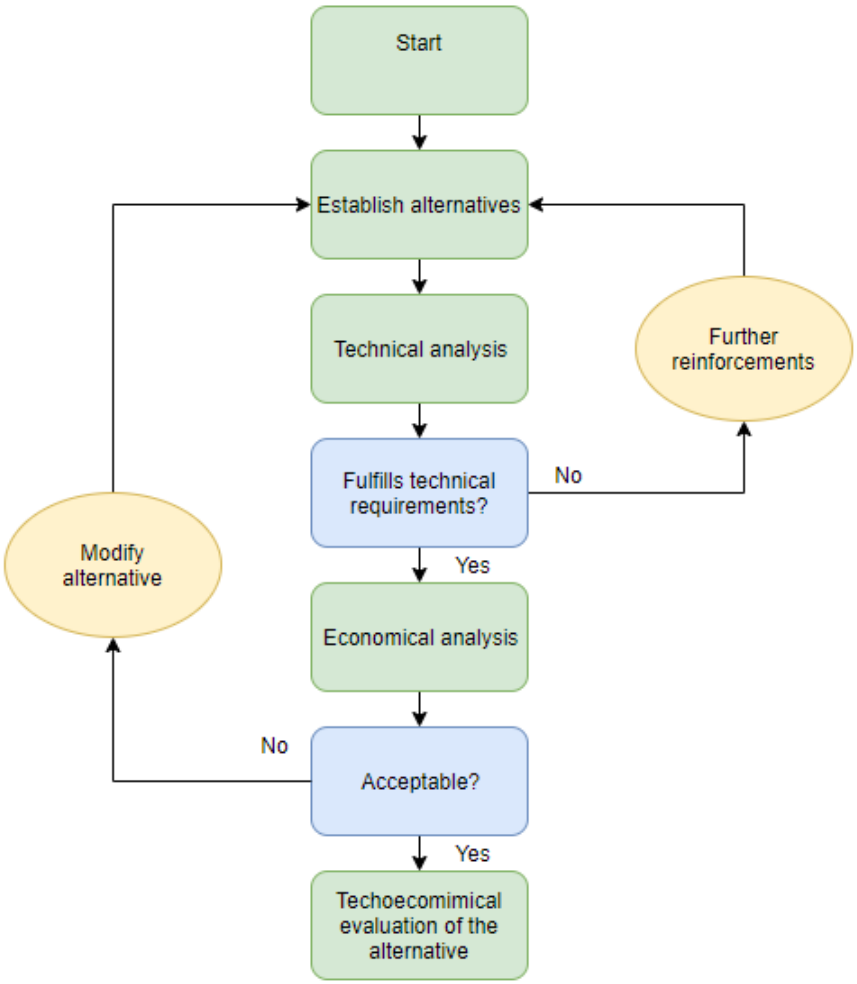

Figure 3.1: Traditional planning of distribution grid, based on a figure in [45]

The starting point in Figure 3.1 is to know the demand, which can be an industry company that want to initiate production in one location and asks the DSO for power supply. Then the DSO needs to establish alternatives to cover this demand, which can be to see if there is any available capacity in an existing power grid nearby, or if reinvestment is necessary. Technical analysis needs to be performed to ensure that all technical requirements are fulfilled. The technical analysis consists of [45]:

- Load flow analysis

- Short circuit analysis
- Analysis of reliability and power quality
- Risk analysis

The technical requirements are amongst others security of supply, voltage quality, frequency and flicker [38]. If the alternative violates some of the requirements, the alternative needs to be modified. If the alternative was to upgrade the power lines to a larger cross-section, a modification could be to increase it even more, eventually to build new power lines, upgrade the power transformer or establish a new transformer station. Once the requirements are fulfilled, economic analysis is the next step, to see how much the alternative will cost. This includes both the investment costs, cost of electric power losses, interruption costs and operation costs over a given period. When the technical and economic analysis is ready, the customer has to decide whether the alternative is affordable or not. If the total cost is not acceptable, one needs to go back and modify the alternative and perform the technical analysis once more. Once they are acceptable, one alternative solution to cover the power demand is found, and the plan can either be realized or compared to other feasible alternatives, where the most profitable for the customer is typically chosen.

3.4 Socioeconomic costs

As there are several alternatives to cover a future power demand, it can be useful to perform socioeconomic analysis to compare them. By socioeconomic calculations, it does not matter who needs to cover the cost. Some alternatives can be more economically beneficial for either the DSO, the operator of the charging station or the end-user, but this will not be taken into account here.

The Norwegian energy act (Energiloven) says that production, transmission and utilization of energy shall happen in a socially efficient manner [20].

> *The Act shall ensure that the generation, conversion, transmission, trading, distribution and use of energy are conducted in a way that efficiently promotes the interests of society, which includes taking into consideration any public and private interests that will be affected. [23]*

This is ensured by The Norwegian Water Resources and Energy Directorate (NVE) by regulating the allowed revenue for each DSO. Every second year the largest DSO in the region has to make a report on the existing capacity in the grid, load flow analysis, energy and power balances and the reliability of the power supply to have a socioeconomic development of the power system [21]. This report, the Power system review (Kraftsystemutredning) (KSU), shall also describe planned grid investments over the next 20 years,

with different alternatives and an argumentation why that investment is important and simplified socioeconomic calculations for the asset.

The net present value is calculated to compare different investment alternatives for the grid. The net present value is calculated by Equation 3.2.

$$NPV = -B_0 + \sum_{t=1}^{N} \frac{U_t}{(1+r)^t} \tag{3.2}$$

where:

B_0 = Investment cost [kr]
U_t = Net cash inflow-Outflow [kr]
r = Discount rate
N = Number of years in the analysis period

As seen from Equation 3.2, the discount rate and the number of years in the analysis period needs to be decided. A separate calculation of the discount rate is necessary for a larger investment, where the risk may vary between different projects. There are normally standardized rates for a smaller investment, where the rate depends on predefined risk levels. Several costs compose the total costs in the distribution grid that will be presented in the following sections.

3.4.1 Investment cost

The investment cost is the total cost of new investment in the grid, including both material costs and the construction cost. The cost of a new power line depends from which cross-section it shall be upgraded, at what voltage level and how difficult the terrain is [45]. It may be hard to anticipate the future cost of an investment, as it will depend from the conditions at that point. If there is a planned road to be constructed at the same time, some of the costs may be reduced since the work can be done simultaneously. It is hard to tell the exact cost of a transformer, but there is an estimate based on a survey in *Planleggingsbok for kraftnett* [45]. This estimate is independent of the size of the transformer, and therefore is the cost of upgrading to for example 20 MVA and 30 MVA considered as the same in this thesis. The investment cost of a battery in the grid does not only consist of the cost of the battery itself but the entire storage system. The cost of the power inverter for a large scale storage battery can be up to 35% of the total system cost [59]. The European trade association Eurobat have reported a cost of 273 $/kWh from some manufacturers, and the price is expected to drop in the following years [59]. The energy capacity is decided from how much energy is needed to be stored in the battery to cover the demand before a recharge is possible. The power capacity is how much power the battery can supply at the same time. A battery supplying the system with 1 MW in one hour before it can be

recharged, will need an energy storage capacity of 1 MWh, while a power rating of 3 MW in the same hour will require a storage capacity of 3 MWh.

When the total cost of an investment is calculated for economic analysis, one needs to compensate for the residual value of the investment. Most power system components have an expected lifetime of 40-50 years, which means that the residual value for the component is expected to be 0 at the end of the analysis period if it is longer than 40 years. For a comparison between alternatives with different lifetimes, compensation for the residual value is needed for the alternative with the longest lifetime. The residual value is calculated by Equation 3.3 [47].

$$PV(I) = I \cdot \varepsilon_r \cdot \lambda_r \tag{3.3}$$

where:

$PV(I)$ = Present value of the investment
I = Investment cost
ε_r = Annuity factor
λ_r = Capitalization multiplier
r = Discount rate

The net present value of the investment can be found by Equation 3.4.

$$PV(I) = (l_{cables} \cdot (I_{cables} + I_{work}) + I_{transformer}) \cdot \varepsilon_r \cdot \lambda_r + I_{battery} \tag{3.4}$$

where:

$PV(I)$ = Present value of the investment
l_{cables} = Length of cables to be upgraded
I_{cables} = Material cost of the cables
I_{work} = Cost of the work to install the cables
$I_{transformer}$ = Cost of the transformer
$I_{battery}$ = Investment cost battery
ε_r = Annuity factor
λ_r = Capitalization multiplier
r = Discount rate

3.4.2 Operational and maintenance costs

The operational and maintenance costs will depend much from where the components are located. If there is a forest close to the power lines, there will probably be a larger need for maintenance due to tree fall compared to areas without forest. An accessible grid area normally has lower costs than a remote area. It will often be difficult to estimate the operational costs, but they are estimated to be around 1.5% of the investment costs due to experienced costs [15].

3.4.3 Cost of losses

There will always be electric power losses in the power system, where the losses are proportional to the resistance in the conductor. The resistance depends on the cross-section of the conductor and the length of it. The losses are proportional to the current squared, and as power is the product of current and voltage, a higher power flow will generate more losses. This means that the size of the electric power losses depends on how much power that flows through the power lines and will, therefore, increase when the load level of a conductor increases. Losses are energy that needs to be produced but cannot be used by any of the consumers. Therefore, the cost of the losses needs to be covered by the grid operator, giving a balance between dimensioning for a grid with low losses but high investment costs, or lower investment costs and higher losses. The power losses compose around 15% of the total revenue cap for the DSOs in Norway [15].

Equation 3.5 shows how the annual cost of the power losses are calculated.

$$K_{loss} = k_{pekv} \cdot \Delta P_{max} \tag{3.5}$$

where:

k_{pekv} = Equivalent cost of losses referred to the annual maximum of the losses [kr/kWh]
ΔP_{max} = Maximum power loss (heavy load) [kW]

Equation 3.5 shows that the annual costs of the power losses depend from the maximum power loss during the year, which can be found by load flow analysis and the equivalent costs of the losses, that are calculated by Equation 3.6.

$$k_{pekv} = k_p + k_{wekv} \cdot T_t \tag{3.6}$$

where:

k_p = Cost maximal power loss (heavy load) [kr/kW year]
k_{wekv} = Equivalent annual cost of energy losses [kr/kWh]
T_l = Utilization time for losses [hours/year]

In Equation 3.6, the annual cost of losses is multiplied by the utilization time for losses. This corresponds to the number of hours with losses in the grid and can be calculated by Equation 3.7.

$$T_l = \frac{\Delta W}{\Delta \hat{P}} \tag{3.7}$$

where:

T_l = Utilization time for losses [hours/year]
ΔW = Annual energy loss [kWh]
$\Delta \hat{P}$ = Peak power loss [kW]

3.4.4 Interruption costs

Interruptions in the grid are caused by faults in a grid component due to several events. It can be due to lightning, ice, wind or overloaded components, amongst others [15]. These factors are very unpredictable, but to estimate the interruption costs, one needs to find the probability for a failure to occur. The security of electricity supply is a measure of the available energy on one point in the grid and how often an interruption occurs. NVE are responsible for registering all interruptions and for giving the grid operators an economic motivation to have good security of supply rather than have a limit on how many interruptions that are permitted [33]. Interruptions will cause a cost for the end-users, and the total interruption costs depend from the distribution of the different customers in the affected grid, and how the grid is constructed. To compensate for that different types of customers will experience different costs during an interruption, the system of Cost of Energy Not Supplied (CENS) was initiated in 2001 in Norway [32]. This takes into account what kind of end-user that is affected by the interruption, at what time and the duration [45]. The interruption cost for a household is the same no matter how long the interruption is, while the cost is increasing a lot depending on the length of the interruption for an industrial customer. Besides, there are correction factors to compensate for at what time the interruption occurs, as it will be more critical for the industrial customer if the interruption occurs during the working hours compared to the of work hours. It is also lower during the summer than in the winter both in the industry and the households. The compensation for at what time the interruption occurs is not taken into account when planning the grid, as there are calculations on how probable an interruption is, but not at what time it happens. The exact cost for the hours the interruption lasted will be compensated for in the cost the DSO will have after the interruption has occurred. Tables for all these factors can be found in *Planleggingsbok for kraftnett* [45], and the resulting specific cost can be calculated by Equation 3.8.

$$K_{P,ref,res} = \sum_{i=1}^{s} k_{P,ref,i} \cdot w_i \tag{3.8}$$

where:

$K_{P,ref,res}$ = Resulting specific cost for the node at the reference hour
$K_{P,ref,i}$ = Specific cost for load category number i at the reference hour
w_i = Share of the load in category number i
s = Number of load categories in the node

In addition to the CENS, there is also a maintenance cost related to repair the damaged components.

3.5 Batteries in the grid

Problems in the distribution grid, such as frequency regulation and large voltage drops have traditionally been mitigated by upgrading the cross-sections of the power lines and installing a transformer with a higher power rating. An alternative solution that has become more present in the later years, as the technology development is going fast, is to use a battery for energy storage in the grid [25]. How beneficial a battery will be compared to a traditional reinforcement depends on how large the energy gap to be covered is, and how often it occurs. This is due to the price and lifetime of the battery, where the price is higher for a large battery and the lifetime will be reduced if the battery is being charged and recharged very often. A battery that needs to be charged many kilowatt-hours or even megawatt-hours a day will require a large charging power which is more expensive than a battery that can be recharged slowly if it only needs to be used once a week for example. For this reason, areas with a lot of holiday houses, where the power demand is low most of the year, and then increases a lot during weekends and holidays, a battery may be a competitive alternative to fulfil the requirements of power quality. Skagerak EnergiLab is a project where it will be installed a battery with a storage capacity of 1000 kWh and a charging power of 500 kW to cover the increased demand during football games. The total price of the battery system is expected to be between 6 and 10 million NOK [8]. This corresponds to a cost per kWh between 6000 NOK and 10 000 NOK and between 12 000 NOK and 20 000 NOK per kW. When it comes to batteries in the grid, the question of ownership needs to be discussed. It seems to be an advantage if the grid company itself can own the batteries and control it, but it may also be a problem, as it will be possible to charge the battery when the power prices are low and then sell the power when the prices are higher. This type of speculation is beyond the role of a grid company due to the economic revenue regulation, which makes it probable that a DSO will not be allowed to own batteries in the grid [36].

3.6 Battery technology

3.6.1 Materials in batteries

The most common batteries in EVs used today are the lithium-ion batteries. The name derives from the material in the electrolyte, which is a salt solution containing lithium ions in this type of batteries [2]. A sketch of a Li-ion battery in a charging and discharging state is shown in Figure 3.2. The principle of a battery is that it can store and release energy by moving electrons between two electrodes, the anode and the cathode. The anode is normally created by carbon in a lattice structure, while the cathode is made from some metal oxide, often cobalt oxide. There is also a separator film between the anode and the

cathode to avoid a short circuit [50]. When the State of Charge (SoC) in the battery is 100%, all the positive charged Li-ions are in the anode in the battery, but will be attracted to the negatively charged cathode and moves from the anode to the cathode. When all of the Li-ions are in the cathode, this will be more positively charged than the anode, and will, therefore, attract the negatively charged electrons. The electrons are forced to move through an electric motor to generate energy on the way from the anode to the cathode. The battery can be recharged by forcing the Li-ions back to the anode by connecting it to a charger with a high voltage. When the SoC is almost zero, there are very few Li-ions in the anode, and they can, therefore, move fast from the cathode with a high voltage. As the SoC is increasing, the anode is getting more packed with Li-ions, and they will move slower from the cathode.

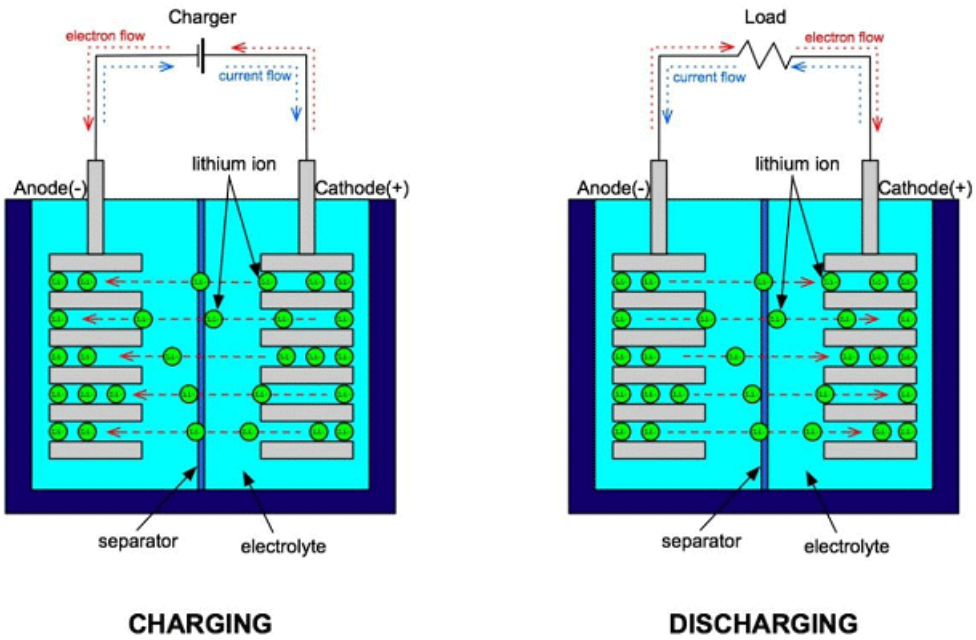

Figure 3.2: The principle of a Li-ion battery[40]

There is much research to make the batteries more efficient and to have a larger energy density. The Norwegian research institution IFE, are working with a solution of replacing the carbon in the anode with silicon, which theoretically has ten times the charging capacity as carbon. The problem is that silicon cannot handle repetitive charging cycles without being damaged, but the researchers found in 2018 a stable solution with silicon that gave five times higher charging capacity than carbon [18]. Due to the massive research in this field, the price of the battery packages is expected to fall. The price per kWh was over 900 $ in 2010, while it was reduced to around 250 $ per kWh in 2018. When the price is

reduced to 125 $/kWh, the EV will be price competitive to conventional vehicles [58].

3.6.2 How batteries are affected by temperature and use

The efficiency and lifetime of a battery depend from several factors, where the most important is from what SoC the charging starts and the ambient temperature. Especially for temperatures below 0°C, the battery will not be able to operate in a good way. A charger with a power rating of 50 kW for 25°C did only deliver 5 kW to the vehicle when the ambient temperature was -25°C and 30 kW in 5°C [57]. This will lead to a huge increment in the charging time and can be a big problem in areas with low temperatures. A study on the Norwegian fast chargers showed that the average charging power on fast charging stations that were supposed to deliver 50 kW was only 30 kW [10]. This may be due to the low temperatures, but can also be a result of wrong use of the chargers. As the Li-ions is moving slower as the SoC increases, the batteries cannot be charged with a power of 50 kW when the anode is nearly full. Therefore it is not recommended to use a fast charger to a SoC above 80% since the power will go down and it will take a long time to charge the battery fully. The reason why many EV owners choose to charge above 80% even that will be more expensive due to the longer time per kWh charged, could be that there is a long distance to the next charging point, so that it will be necessary to use nearly 100% of the battery capacity to get to the next available charging point. Another possibility is that there is a lack of information among most of the EV-owners. Figure 3.3 shows how the charging power is reduced when the SoC increases for a Tesla Model S85.

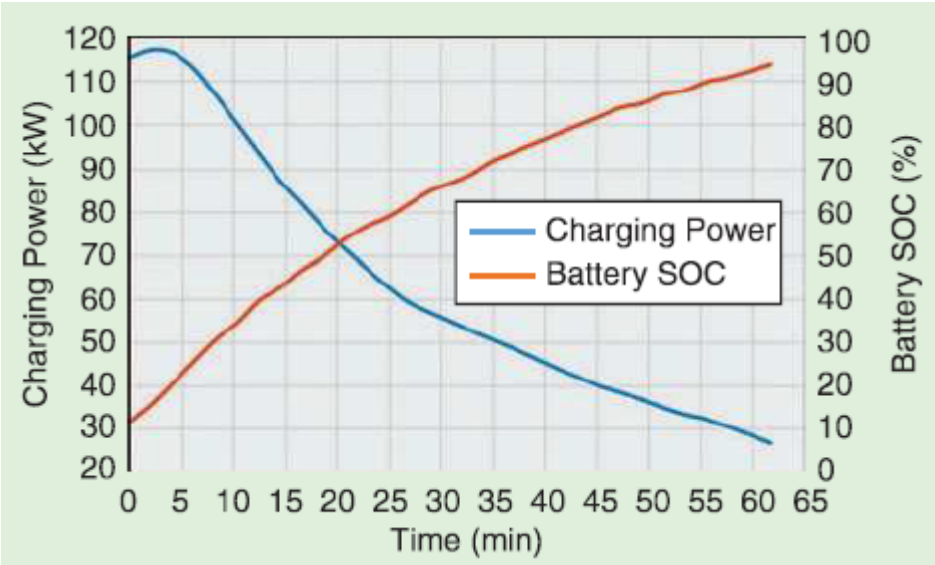

Figure 3.3: Battery SOC and charging power for a Tesla model S85, figure from [17]

This also applies for large scale batteries in the grid, where the ambient temperature

affects the efficiency of the battery. The number of charging cycles for a battery is not infinite, which means that a battery that needs to be recharged almost every day will have a shorter lifetime than a battery that only needs a recharge once a week or once a month. Overload of the battery will also reduce the lifetime a lot. It is hard to say what will be the lifetime of a battery in the grid, as this is not very common yet, but it is expected to be between 5 and ten years for the lead-acid battery, and very unlikely to reach 20 years [41].

3.7 Analysis in Netbas

The grid information software Netbas will be used to perform analysis on the grid in this thesis. The software is developed by Powel and is widely used among grid operators in Norway. The software contains information about all components in the grid, including the end-users. The dimensions of each component and the annual energy consumption for each customer is the basis for all calculations performed in Netbas. To perform analysis on a specific day and hour, one needs to calculate the instant power in that hour from the annual energy consumption. The way this is done is first to specify what type of load it is, for example, a household or an industrial customer, where the variation in consumption throughout the day, week and year is different. A household has typically a cycle where one can see one peak in the consumption every morning before work hours and one peak in the hour after work. The peaks on the weekends will typically be delayed, and also lower than during the weekdays. An industrial customer, for example, a paper mill with production Monday through Friday 8-16 will have a profile with peaks in those hours, and nearly no consumption the rest of the time. The calculations are done using Velanders formula Equation 3.9, where the constants vary depending on the end-user.

$$P_{max} = k_1 \cdot W + k_2 \cdot \sqrt{W} \tag{3.9}$$

Where:

P_{max} = Peak power during the year [kW]
W = Annual energy consume [kWh]
k_1, k_2 = Constants that depend from which type of load it is

The end-users are divided into more than 30 different groups with individual consumption profiles given by the Velander coefficients for each of the groups, though all customers within the same group are modelled to have the same consumption profile. Therefore this is a factor of uncertainty for the calculations, as they are based on standardized values and not the actual use. The values are generally set to high to avoid that it will be any overloads due to errors in the calculations, but it may lead to over-dimensioning of many

components. There is also a lack of a group for fast charging of EVs, which means that it will be necessary to find a probability distribution of the consumption throughout the year.

As Eidsiva Nett operates both the distribution grid and the regional grid, both of the grid levels are available in Netbas. This means that it is possible to perform a calculation on the regional grid to see the consequences of adding a charging station in the distribution grid, but this requires that all the load in the entire regional grid is modelled correctly to make any sense. This means that one has to check that every end-user is connected correctly and are modelled with the correct end-user group and annual energy consumption. This will require much time, and it will be hard to avoid somewhat uncertain results. Therefore the analysis in this thesis will focus on the distribution grid, including the power transformer from the regional grid, supplying it only.

For all loads in Netbas, one has to choose which conversion factor to be used to calculate the maximum power. This can be by the Velander coefficients, time of use, total energy consumption or power. The maximum power of the household customers is found by the time of use, as one does not know what the peak load is or can be. For a charging station, it may be convenient to use the conversion factor based on the power, which gives that the maximum available power is used during the peak load of the charging station.

Netbas can give detailed simulations for one year, where the variation in the load on the different days and hours are the basis of the calculation. One can set the calculation to be in a specific year, where there is also an option to choose the annual load increment to see how the losses will be different in 10 years compared to this year.

It is simply to change the power rating directly by overwriting the size of the transformer in the grid in Netbas to upgrade it. To change the dimensions of the power lines and cables, one can replace them with other standardized models. After the changes are done, one can run another simulation to see the differences.

There is possible to perform economic analysis in Netbas too, where the input is the cost of energy losses, the cost of power losses, number of years in the analysis period, the discount rate and the utilization time for losses. If the option *total cost* is chosen, Netbas will calculate the total costs over the analysis period, including the component cost, operation cost and the cost of losses. If not the costs of operation and components are specified, those costs will be excluded from the total costs, giving only the cost of losses. The cost of losses is based on the parameter input and the losses in the grid, where it distinguishes between what is losses in the transformers, in high voltage cables and what comes from low voltage, as this gives different costs.

Chapter 4

Method

When a customer has decided to build a charging station with a given power at a specific location, it may require reinforcement of the grid, where the customer has to cover some of the costs (Anleggsbidrag). Some customers may be more flexible on the location of the charging station, giving the opportunity to check different locations to find the most beneficial solution socioeconomically.

In this thesis, it will be developed a method for planning a charging station for fast charging of EVs and freight transport. This will be done by looking at the technical requirements for a charging station as well as the non-technical aspects, such as if the location is a natural place to stop while charging, meaning that some necessary facilities are nearby. If one can know how the traffic flow will be through a specific point by the road, one can estimate when the peak hour for the charging station will be and further use that when considering whether traditional reinforcement of the grid or alternative solutions such as batteries will be most economically beneficial.

When considering a charging station by the main roads, the first thing one has to do is to get an overview of the transformer stations that can be relevant for supplying a charging station. To see if the transformer itself has sufficient capacity for the extra load, one can look at by how many percent the transformer was loaded at the peak hour of the transmission grid. By this method, one can do a quick check whether it may be possible or not to add a huge load from a charging station without upgrading the transformer. Even if there is free capacity on the transformer itself, one does not know if this capacity is distributed more or less equal for all the outlines, or if nearly all of the capacity is in one radial. Even though there is enough capacity in the transformer, it may be that all the power lines are running close to their maximum load so that they cannot handle an increased power flow. This can be mitigated by upgrading the cross-section of the power lines or installing a load break switch with a higher capacity. This charging stations will in most cases require a separate substation connected to the high voltage distribution grid, so it will not affect the low voltage distribution grid in any other way than that the voltage

drop from the transformer to the substation may be higher. To simulate a charging station in the high voltage distribution grid, one can connect a new load on the high voltage side of a substation, which corresponds to a location between two existing substations. By analyzing the grid with the extra load, one can see where in the grid the bottleneck will be and later where it will be most crucial to perform upgrades in the grid. Even if all the components in the grid will handle the increased load, there will be higher electric losses, generating higher costs. Therefore it may be necessary to look at different locations or reinforcements to avoid those losses. In general, a location close to the transformer station will generate less losses than a location far out in the distribution grid, due to the shorter distance for the power to flow.

4.1 Load profile over the year

4.1.1 Data from traffic counting

Statens Vegvesen has several points along the main roads in Norway where every vehicle passing that point is counted. By these statistics, one can see how many vehicles are driving on the road where the charging station is intended. How many of them are EVs, and how many of them need to charge at a given point? Moreover, how many at the same time? One approach is to see how many vehicles that are driving through in total, and assume that the busiest hour during a year gives the peak load of the charging station, and then obtain a charging profile based on the total number of vehicles driving through the point. Figure 4.1 shows the total number of vehicles driving through a point on E6 near Lillehammer at different days in 2019. Figure 4.2 shows how many of the vehicles in Figure 4.1 that are longer vehicles. Longer vehicles include both buses and freight transport, as all vehicles longer than 5.6 meters are represented in these statistics. The other vehciles represents both passenger cars and vans.

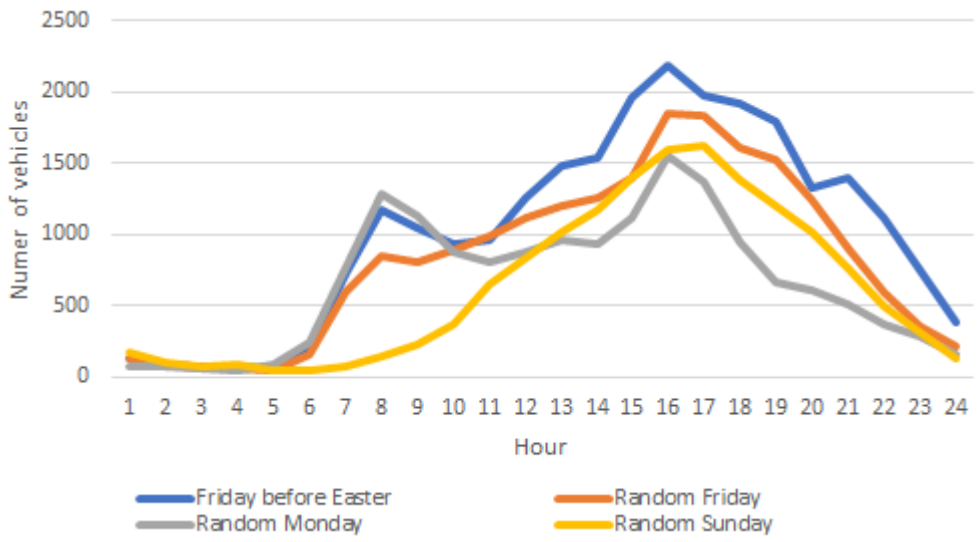

Figure 4.1: Total number of vehicles driving through a point on E6 near Lillehammer

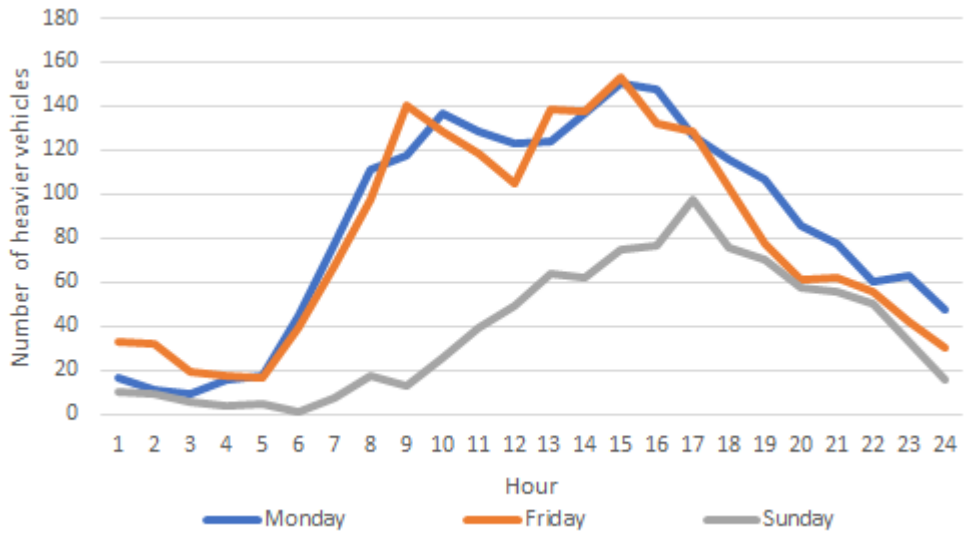

Figure 4.2: Number of heavier vehicles driving through a point on E6 near Lillehammer

Figure 4.1 shows the traffic through a point on E6 near Lillehammer a random Monday in 2019 to represent a typical working day, this curve shows that there are two peaks during a day, one in the morning between 8 and 9 and one in the evening between 16 and 17. This represents the travel to and from work. The figure also shows a random Friday and Sunday to illustrate the traffic on the weekends. On these curves, there is a peak during the afternoon, between 16 and 18 and it is interesting to see that this peak is around 25%

higher than for a Monday and lasts for one more hour. The blue line shows the day with the most traffic in total so far in 2019, the Friday before the Easter holiday. One can see that this day starts as a typical Friday, but the traffic through this measure point starts to increase earlier, and the peak is getting even higher.

Figure 4.2 shows the number of heavier vehicles passing through the same point near Lillehammer. One can see that a regular Monday and Friday have almost the same curves, with a more even stream of vehicles from 8 in the morning until 18 in the evening. The traffic during a Sunday is much lower.

4.1.2 Recommendations from Elbilforeningen

Elbilforeningen have made a report with recommendations for the future demand of fast charging stations [27]. They recommend a fast charging station with at least 50 fast chargers every 150 km along the main roads in Norway. E6 in the area of Eidsiva Nett is more than 200 km, which means that it has to be at least one charging station in the area. This recommendation will make the basis for the calculation of the peak load of a charging station in this thesis. It is assumed that there will be 50 chargers with a power of 150 kW, in total 7.5 MW at the charging station. The recommendation from Elbilforeningen is that the capacity shall be 10 MW, but instead of increasing the charging power in the existing chargers or to add more chargers, the last 2.5 MW will be intended for freight transport and local buses. Exactly how this is done practically will not be treated in this thesis, but the point is that the maximum power of the charging station will be 10 MW, and the station will be available both for passenger cars and heavier vehicles. The same energy demand can also be covered by several smaller, more frequent charging stations, that will have a different impact on the grid, but that will not be considered in this thesis.

4.1.3 Charging pattern

The charging pattern in Figure 4.3 is based on data from traffic counting on E6, where Monday till Friday have the same charging pattern, and Saturday and Sunday have the same. This is because of that Netbas, to tool to perform the grid analysis, only distinguish between weekdays and weekends. Therefore, the charging patterns on weekdays are made from an average between all the weekdays and the same for the weekend. From the graph, one can see that there is one peak in the morning around 9, this probably represents people driving to work. It is also reasonable to think that driving home from work is a large part of the traffic, making a peak in the evening. As the situation is today, most of the EV owners can charge their vehicle at home, which means that this group probably would not stop to charge on the way to or from work. However, all the traffic is included in this thesis, as it is challenging to decide how many of them who will not charge in these hours. The

graph in Figure 4.1 shows that the traffic peak occurred the Friday before Easter and it is reasonable to think that there are more days during a year with more traffic than a random Monday, Friday and Sunday. However, if the charging station should be dimensioned to handle the most trafficked hours without generating a queue, the charging station would most probably not be very socioeconomic beneficial. The difference from the busiest month July to the month with the least traffic, December, is more than 30%. This is only due to the lower traffic from the counting today, not taken into account that colder weather may require more charging due to more energy use in the batteries.

From Figure 4.1 and Figure 4.2, one can see that the peak for heavier transport is longer and starts earlier than the other vehicles, this means that it may be a good idea to share the power between the two categories. As trucks are physically larger than passenger cars, the charging lots will require larger space. One option is to build some charging points large enough for trucks, but available for passenger cars. Another option is to separate the charging points and have a switching system for the power supply to activate the passenger car charger when the truck charger is out of use.

The monthly profile was found by dividing the number of vehicles through a point during a month by the number in the month with the most traffic. As July was the month with the most traffic, the percentage for that month will be 100%. The same method was used to find the variation through a day, where the number of vehicles every hour was divided by the number of vehicles in the most trafficked hour. This gave only 100% use of the charging station once a day, which is probably not a good way to design a charging station, as it will be reasonable to consider a queue. Therefore, all the percentages were multiplied by 1.25, to simulate that there will be a queue if the total traffic is 80% of the maximum or more. Consequently, the hours that had more than 80% became larger than 100%, this was compensated for by setting the value to 100% and also increasing the next two hours to 100% to get approximately the same amount of energy in total. The resulting parameters used in the analysis is given in Table 4.1 and Table 4.2.

Table 4.1: Variation of the load through the year

Month	% of max
January	68
February	78
March	80
April	76
May	75
June	88
July	100
August	97
September	83
October	77
November	70
December	66

Table 4.2: Variation of the load through a day, in percent of maximum load

Hour	Weekday	Weekend	Hour	Weekday	Weekend
1	11%	13%	**13**	93%	77%
2	9%	8%	**14**	95%	86%
3	6%	6%	**15**	100%	100%
4	6%	6%	**16**	100%	100%
5	8%	4%	**17**	100%	100%
6	21%	3%	**18**	100%	100%
7	57%	6%	**19**	87%	90%
8	88%	12%	**20**	73%	75%
9	86%	17%	**21**	58%	59%
10	81%	28%	**22**	41%	41%
11	80%	49%	**23**	30%	26%
12	85%	62%	**24**	19%	11%

Figure 4.3 shows a possible charging pattern for a weekday in July and January, while Figure 4.4 shows the same for weekends. The y-axis shows the charging power in MW for each hour during the day.

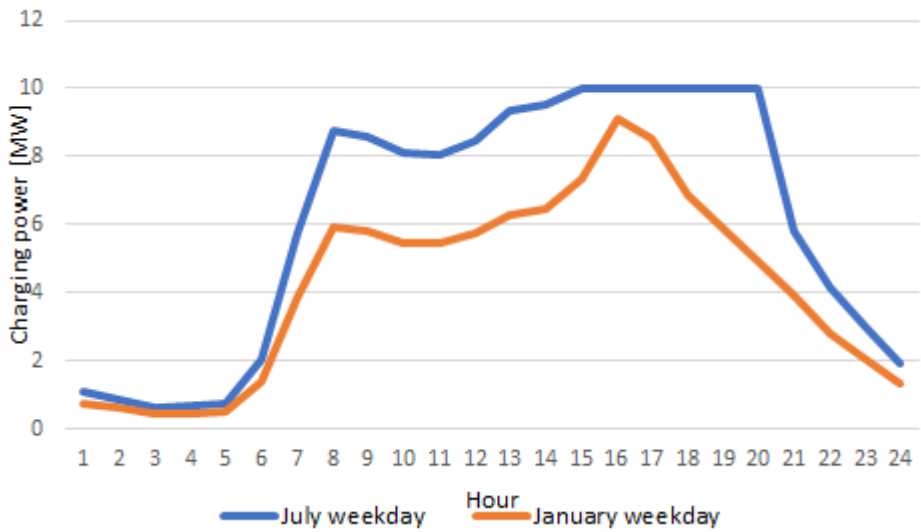

Figure 4.3: Required charging power for a weekday in January and July according to the model described in this chapter

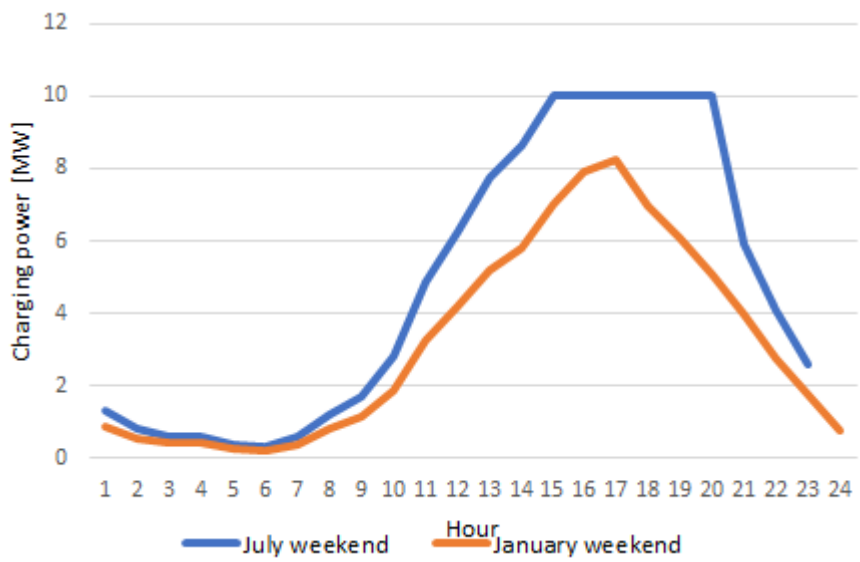

Figure 4.4: Required charging power for a Saturday or Sunday in January and July according to the model described in this chapter

Figure 4.3 and Figure 4.4 shows the charging pattern for a weekday and weekend in January and July made from the model described in this chapter. The percentage of the consumption every hour is multiplied by 10 MW as that is the maximum power of the charging station. One can see that the charging station will be loaded more than 100%

every day in July, lasting for four hours in both the weekdays and the weekends. The loading is more than 80% from 8 in the morning till 19 in the evening in the weekdays in July and from 13 to 19 on the weekends. The maximum power in January was found to be 8.25 MW and is below 6 MW most of the day.

4.1.4 Requirements for the security of supply

When considering a charging station, one needs to decide whether there shall be redundancy in the grid or not. If there is a requirement saying that full available power to the charging station shall be a high priority in the grid, there has to be built more power lines to ensure that it will have power if a fault occurs somewhere in the grid, giving a large investment cost. Another option is that the charging station can be a more flexible load, where higher prioritized customers can use some of the power capacity in the transformer and the power lines. The result of this option may be that some of or all the power in the charging station may be disconnected and the EV owners may experience that the charging goes slower or that it is out of order while the failure is being fixed. To have this deal with the grid operator can be very economically beneficial, due to lower tariff costs. The price per kilowatt installed power depends on how flexible the load is, like how much of the installed power that is for disposition, how long the interruption can be and if it is necessary that the interruption is warned or not [7]. Even if a solution with flexible load will have less investment costs, it may not be a good idea for a fast charging station. A charging station out of order will be very costly for freight transport and other vehicles that are dependent on the vehicle to do a job. Therefore, a charging station will most probably need a high priority in the grid, at least for some of the power. If it, on the other hand, is loads in the grid that can be more flexible, for example, hot water tanks, it can increase the security of supply for the charging station.

4.2 Location of the charging station

In the KSU there shall be a table showing the load in each of the transformer stations in the licensed area at the peak hour of the transmission grid, given by Statnett. This hour may not coincide with the local peak hour due to, among others, weather conditions. As the capacity in MVA of the transformer is known, one can easily see by how many percent out of maximum the transformer was loaded in the peak hour. The values may need to be temperature corrected, as the actual year might have been warmer than others, giving a lower energy consumption. The first thing to do when considering a location for a fast charging station is to find transformer stations close to the road where one wants to establish it. There may be several alternatives, where a good starting point may be the one with the most available capacity or the one closest to the road. The location within the

transformer station will also have to be decided and can be in one of the existing radials, or by creating a new one exclusively for the charging station.

4.3 Alternatives

4.3.1 Alternative 1 - Zero alternative

The first alternative is not to do anything at all, generating zero investment costs except from the costs related directly to charging station itself, which is neglected here as it applies for all the alternatives. This will, in all cases, lead to increased power flow in the power lines and a higher load level for all components. How much the loading increases will decide if this is a feasible alternative or not, which can be seen by the technical analysis. The increased load will also generate increased losses and increased costs of the losses. The question is then if they will be higher than the cost of upgrading the grid. A higher load level may also have an impact on the security of supply.

4.3.2 Alternative 2 - Traditional reinforcement of the grid

The second alternative is to upgrade the power lines and transformers to a level that are sufficient to fulfil the technical requirements. This is done by looking at the results from the zero alternative and then change the dimensions on the overloaded components until they are not overloaded anymore. Both building a new line and upgrading an existing line can be a realistic alternative, depending on the placement of the charging station and the difficulty of the path from the transformer to that point. In this thesis, all the power lines are upgraded to the same dimension, which may be necessary anyway since the charging station will be a very large load in the grid. The same yields for the transformer, where one can upgrade one of the existing, add another transformer to the transformer station or establish a new transformer station somewhere else in the grid.

4.3.3 Alternative 3 - Upgrade the gird to 70% of the peak load, and install a battery to cover the last 30%

This alternative looks at the possibility of upgrading the power grid to a level that can handle a load of 7 MW at the charging station. It is possible that this can be a sufficient reduced power demand to avoid upgrading of the transformer or even of the power lines for some locations and is a solution worth to consider. The intention is that it in any hour during a day will be 7 MW available, but some of this power needs to be used to recharge the battery with a capacity of 3 MW. This option will require that the power demand at the charging station is lower than 70% of its maximum so many hours a day the battery

needs to recharge and that the battery has large enough capacity to last for all the hours with more than 70% power demand.

4.3.4 Alternative 4 - Install a battery at the charging station to avoid reinforcement

The fourth alternative is only to install a battery at the charging station to cover all the additional load the existing grid cannot carry. If the size of the charging station needs to be 10 MW, but only 4 MW is available without any reinforcement, it can be solved by installing a battery with a capacity of 6 MW to cover the demand. If the grid has a low capacity without any upgrades, this will require a lot from the battery. It needs to have large enough capacity in kilowatt-hours to cover all the hours with a higher load than the one available without the battery, and it needs to have high power capacity to be recharged during the hours with a load lower than what the existing grid can handle. In some situations, this cannot be possible at all, as the total energy that the grid can supply during a day is lower than the energy that needs to be consumed. This also depends upon that the price of the battery solution is lower than the other alternatives, which will be a more significant challenge as the technical requirements are high.

4.3.5 Alternative 5 - Smart power management

This alternative considers the alternative of avoiding costly upgrades in the grid, but solve the problems that might occur with a charging station by smart management of the power supplied to the charging station. The power supplied to the charging station shall be so low that the loading of the power transformer never exceeds 120% in the peak load hour. This can be tolerated as long a the peak load occurs during the winter when there is good cooling of the transformer due to the low ambient temperature. The management system is in this thesis thought to exists, and even if this system will have both an installation cost and an operational cost, this is neglected here. This will require that the charging station is a flexible load so that the available power depends on the other loads in the grid and will vary throughout the day and over the year. Before this solution can be considered, one needs to decide what is the absolute minimum power to be delivered to the charging station, and for how long the low power can last. For some locations, a solution with smart power management can result in zero kilowatts delivered five hours a day during heavy load, while others can supply more than 60% of the nominal power even in the busiest hour for the rest of the grid. Some grid locations may need an upgrade of the power lines in all cases, but the transformer can remain the same with smart power management. Other grid areas will not need an upgrade at all, as the smart management can give sufficient power supply to the charging station with the grid that exists today. The required charging power represents

the amount of energy needed for the vehicles to drive the lengths they are supposed to. This means that by reducing the available power for some hours also reduces the energy delivered to the EVs. Figure 4.3 gives that the total power demand based on the average values for each hour during the day is 661 MWh in January and 960 MWh in July. If the supplied power is reduced in some hours, it must be covered by postponing the charging to hours when the grid is less busy. For some locations this will be to defer the charging peak until 22-23 o'clock, other locations will require that the charging is done during the night between 1 and 5 for example, or it can be some locations where this energy amount is not available at any time for the grid, and the solution with smart power management is not even theoretically possible.

4.4 Technical analysis

The technical analysis will be performed in Netbas, as described in the theory chapter. It will be checked if some of the components will be loaded more than acceptable to verify that it fulfils the requirements. The technical analysis will only be done for the peak load hour, as this hour will be crucial for if the grid dimensions are good enough. It does not matter if the load is low 360 days a year if it is so high that it breaks the components during peak load. It will not be performed risk analysis or short circuit anlysis in this thesis.

4.5 Economical analysis

The economic analysis will be performed for ten years, as the expected lifetime of a battery is no longer than ten years, even if power cables and transformers have a lifetime of about 40 years. Therefore the residual value of the components with longer lifetimes needs to be compensated. Instead of calculating the net present value over 40 years and include several battery changes, the economic analysis will show how a battery can be competitive against traditional reinforcement of the grid, and if it can be a good solution for postponing an upgrade with ten years for example. If that is competitive, it can be beneficial, as it is hard to tell how the further development of electric vehicles and the need for charging will be in the future.

The analysis will be done by calculating the total cost of the investment and the losses over the first ten years after the installation, and the parameters used for the analysis is shown in Table 4.3. There will not be performed complete economic analysis on the interruption costs, but there will be discussed how much a one-hour interruption in the reference hour caused by the charging station will cost, to compare the different locations.

Table 4.3: Parameters for the economical analysis

Discount rate	4.5%
Number of years	10
Cost of energy loss	26.5 øre/kWh
Cost of power loss	684 kr/kW
Utilization time of losses	4000 hours

Table 4.3 shows that the chosen discount rate is 4.5%, and the cost of power loss and energy loss is set to the cost levels of 2019. It is hard to say when this charging station is to be built, but as long as the cost will be the same for all alternatives, it will make a fair comparison between the alternatives. The utilization time of losses was found by Equation 3.7, where the energy loss and the peak power loss found by the analysis is the input. The resulting utilization time of losses was not exact 4000 hours for any of the alternatives, but it can be seen as an average to make the different locations and alternatives comparable.

While the investment costs of the power lines and transformers can be found in *Planleggingsbok for kraftnett* [45], the investment cost for a large scale battery is not so easy to anticipate, as there are only a few existing large scale batteries in the grid today, and very little data on the prices of them. As described in the theory chapter, the storage price of a battery was 273 $/kWh, around 2400 NOK/kWh 2018. This price is independent of the power capacity of the battery, but in the lack of reasonable estimations on the total cost, it will be used in this thesis to compare the alternatives that include reinforcement of the power lines and transformers with the alternatives that include a battery solution. For each location, the total cost of the battery system to make a battery solution price competitive to a non-battery solution will be calculated.

The method for calculating the total costs of losses in Netbas does not work properly for the fifth alternative, as it will require a load profile that changes every hour depending from the other load in the grid. Therefore will only the peak losses be calculated, and the total cost of losses over ten years needs to be estimated. It is assumed that there is a linear relationship between peak loss and the total cost. Interpolation will be used to find an approach for the total cost of losses.

4.6 Evaluation of the security of supply

There should be done an evaluation of the security of supply for the investment alternative and for the location itself. If the most beneficial solution technically and economically is to use a battery in the grid, it can affect the security of supply in another way than a solution where the cables and transformer station is upgraded. A battery can be seen

both as a strength and a disadvantage regarding the security of supply, a fully charged battery may operate as a power source during faults in the grid in order to operate at normal conditions, but as it is another electrical component installed in the grid, it is also another source of failure. This needs to be evaluated, where the consequences of reduced security of electricity supply may be more crucial in certain areas. The composition of the other customers in the grid sharing the same power supply as the charging station may make one possible location more suitable than others. If one considers that the probability for a failure caused by the charging station is the same for all locations, the CENS will be higher for a location with many commercial customers compared to a location with many household customers. The same yields for the interruption caused by other things in the grid that affects the charging station, as the probability for a fault may be higher in certain areas. There will not be performed complete analysis on the security of supply in this thesis, but it is considered as an important factor when planning a fast charging station. The distribution of the different customer groups will be presented for the radial and the transformer in each location to compare the interruption cost. The distribution will be shown in percent of the total power consumption in the reference hour when it was downloaded from Netbas, without the charging station included. The customer groups are:

- Agriculture
- Household
- Industry
- Commercial
- Public sector
- Large industry

The interruption cost for a one-hour interruption in the reference hour can be found in *Planleggingsbok for kraftnett* [45]. The CENS calculations can be found in Appendix A.

4.7 Evaluation of the location

Even if a location is both technical and economically feasible, it might still not be a good option for a charging station. A charging station will require much space and cannot be a difficult place to stop for charging, which means that the station is accessible from the road. The rules regarding driving times before one needs to have a break for freight transport drivers is also a thing to consider as the locations for rest should coincide with the location for charging. If it has to be done many changes in the infrastructure around the charging

station to make it possible to use, it might also generate high costs. There will be a need for additional services around the charging station, at least at the level of the gas stations that exist today, like restrooms and fast food services. These facilities will most probably establish themselves more or less when the charging station is built, but it is important to consider if it can be easier some places than others.

A summary of the method described in this chapter is shown in the flow chart in Figure 4.5.

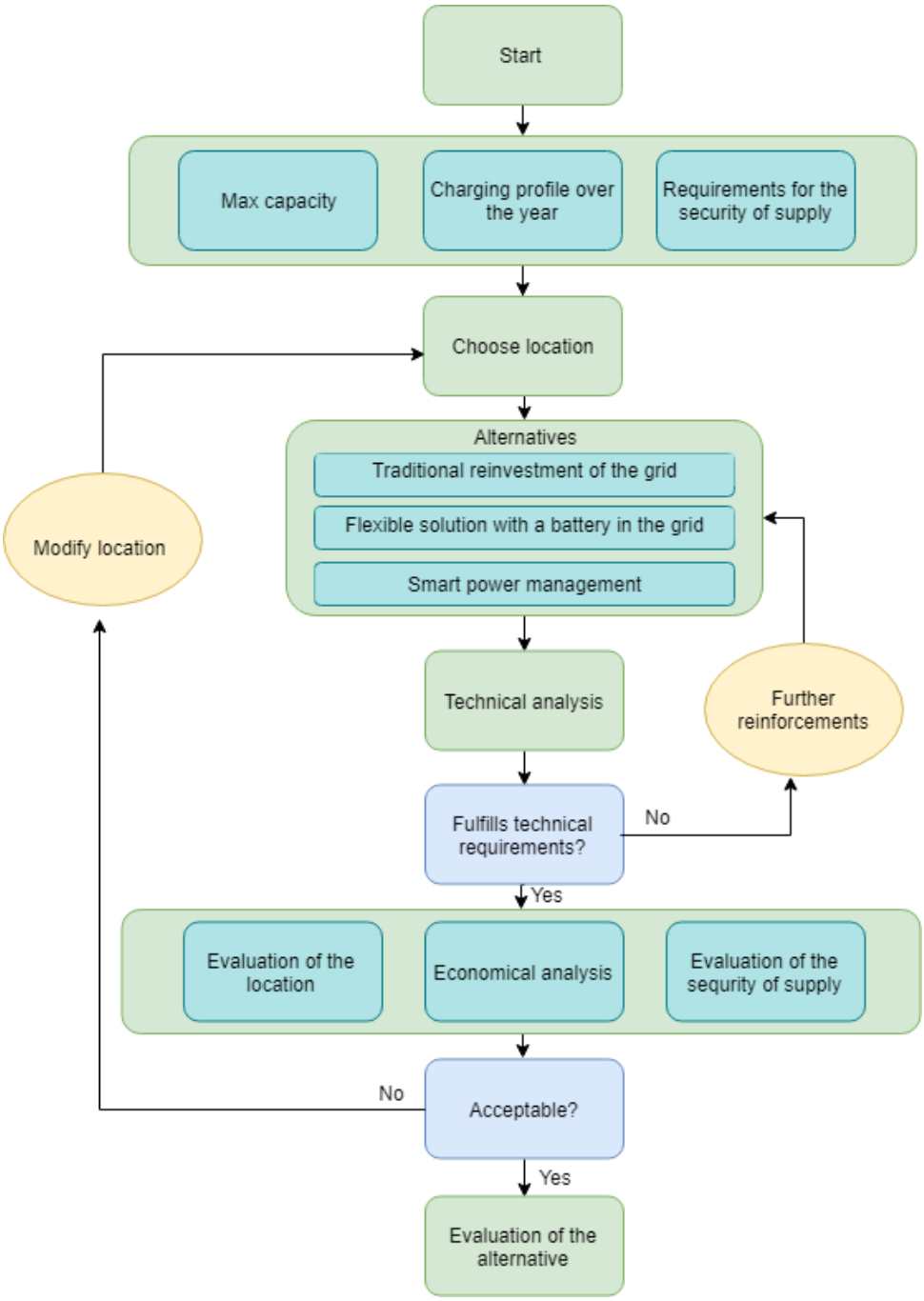

Figure 4.5: Method for planning a fast charging station

The flow chart in Figure 4.5 is not very different from the flow chart of the traditional planning method shown in Figure 3.1, but it has more inputs, three different categories for the reinvestment alternatives and also an evaluation of the security of supply and the location in addition to economic analysis. The main difference from the traditional method

is that the grid owner will have a more active role in deciding the location of the new load. In the traditional planning method, it is the customers that ask for a new connection for a load in one specific location. Then the DSO is responsible for finding a technical solution and an estimate of the costs. If the costs are affordable for the customer, the solution will be chosen, and if not, the customer will have to suggest a new location. This means that the method developed in this thesis requires cooperation between the DSO and the charging operator to find the optimal location and the best alternative.

Chapter 5

Application of the method

The method developed in the previous chapter will be used at different locations along the main roads in the area of Eidsiva Nett, to see which factors in the model presented in the previous chapter that is most important when it comes to the selection of optimal placement of a charging station. Some of the data presented in this chapter will be considered as sensitive information for the power system (Kraftsensitiv informasjon) [22]. Therefore all the locations will be anonymous in the technical and economic analysis, while there will be a brief review of the real locations at the end of this chapter. The model described in the previous chapter starts with deciding the max capacity, the charging profile over the year and the requirements for the security of supply for the charging station. The focus in the application of the method is to compare different alternatives and locations, which makes it reasonable to use the same factors for all alternatives. The maximum capacity, which corresponds to the maximum available power is 10 MW, and the charging profile over the year is as described in the previous chapter. The requirements for the security of supply is in this thesis, is for simplification, only to build one line to the charging station, which means that there is no redundancy for the charging station. Which priority the charging station shall have during an interruption is not considered in this chapter, but it will affect both the investment cost, the cost of operation and how reliable the charging station will be for the end-users. The operational costs are not included in this analysis, as they are assumed to be more or less the same for all locations, and will therefore not be very interesting in the comparison between them. The operational costs will probably be different between the alternatives, but as it is the same alternatives that are evaluated for each location, it will be neglected in this thesis. In a complete analysis, both the total interruption costs and the operational costs should be calculated. The calculation of the investment costs and the interruption costs can be found in Appendix A, and the results from the simulations in Netbas can be found in Appendix B. In the model shall one alternative in one location be analyzed completely and modified if necessary before moving on to the next alternative or location. The results from the different steps in the

model will be presented simultaneously for each location to make the comparison easier. An evaluation of the real locations and a comparison of all the locations will be presented at the end of this chapter.

5.1 Location A

There is a transformer station with two transformers close to the location of the charging station in this location. It was around 6 MW available power during the peak load hour in 2017, which means that by rearranging the load points, one can obtain 6 MW extra power somewhere in the grid. The voltage level of the high voltage distribution grid is 11 kV.

5.1.1 Alternatives

Table 5.1 shows which upgrades that is done for the different alternatives in location A.

Table 5.1: Alternatives location A

	Power lines	**Transformer**	**Battery**
A1	-	-	-
A2	3x1x630 Al	Yes	-
A3	3x1x400 Al	Yes	3 MW
A4	-	-	6 MW
A5	3x1x630 Al	-	-

Table 5.1 shows that there is no upgrades in the first alternative, while the power lines and transformer is upgraded in the second alternative. The third and forth alternative includes a battery solution and alternative five is the alternative with smart power management.

5.1.2 Technical details

Table 5.2 shows the results from the technical analysis in Netbas for the different alternatives in this location.

Table 5.2: Technical details location A

	0	**1**	**2**	**3**	**4**	**5**
Peak losses [kW]	756	1,191	807	792	885	741
Annual losses [MWh]	2787.3	4578.2	3077.8	2991.6	3242.2	
Load cable	92.1%	237.0%	92.2%	86.5%	150.3%	80.9%
Load transformer	110.3%	192.1%	92.6%	80.7%	140.3%	118.6%

Table 5.2 shows that alternative one is not technically feasible due to the high load level of the transformer and the power lines. Alternative four is not very feasible either since the cables are overloaded with more than 50%. Both alternative two and three are technically feasible and can supply the charging station with the desired power at all times. Alternative five is also technically feasible, as that is the basis of that alternative, but it cannot supply the desired power to the charging station every hour during the year. Figure 5.1 shows how the maximum charging power will be for a weekday in January and July with and without the smart power management system.

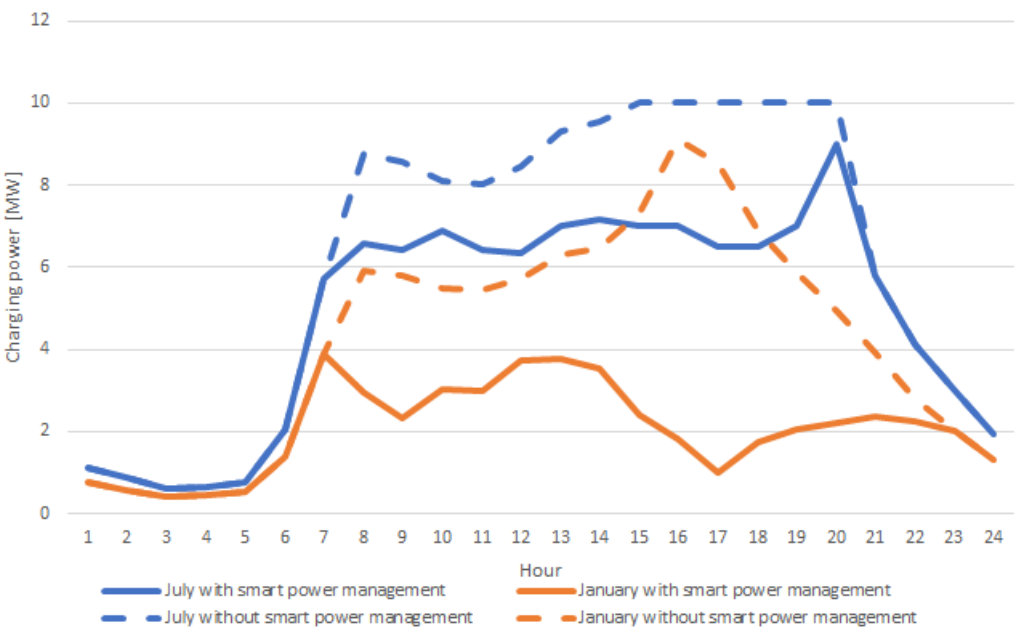

Figure 5.1: Available charging power for a weekday in January and July with and without smart power management in location A

As seen in Figure 5.1, the capacity in this transformer station during the summer is pretty good compared to the winter months. This gives approximately 70% of the desired charging power most of the day in July and less than 50% most of the day in January.

This will result in queues that last until midnight in July, while it will require charging all night to cover the total energy demand in January.

5.1.3 Economical aspects

Table 5.3 shows the costs of the investments and the losses for ten years for the different alternatives. As the battery price is an unknown factor, the price of the battery is represented with the letter B in the table. The total length of the cables to be upgraded in the alternatives that include that is 1.929 km, and the terrain is characterized as suburban.

Table 5.3: Costs location A

	0	**1**	**2**	**3**	**4**	**5**
Investment cost [kkr]	0	0	3,893	3,704 + B	B	900
Total cost of losses [kkr]	5,945	15,977	8,162	8,211	8,887	5,000

Table 5.3 Shows that alternative two and three have approximately the same costs of losses so that the total cost will depend on the investment cost of the battery. Alternative four has circa the same cost of losses too, but that alternative was found not to be technically feasible. Alternative one is not technically feasible and should not be considered, but one can see from the table that the cost of losses is twice the costs in the other alternatives. The alternative with smart power management has the lowest investments costs and lowest cost of losses, but cannot be directly compared to the other alternatives as it does not fulfil the same requirements regarding the charging power. Figure 5.2 shows that alternative one is the cheapest when the battery price is 2400 NOK/kW, and the alternatives with batteries are the most expensive. Figure 5.3 shows that the total cost of alternative two and four are equal when the battery price is 90 kr/kW.

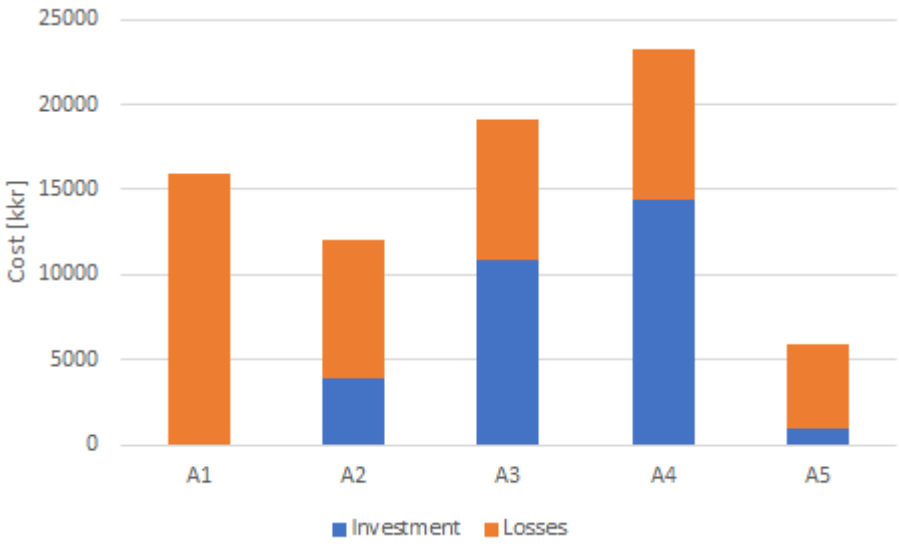

Figure 5.2: Total cost location A when the battery price is 2400 kr/kW

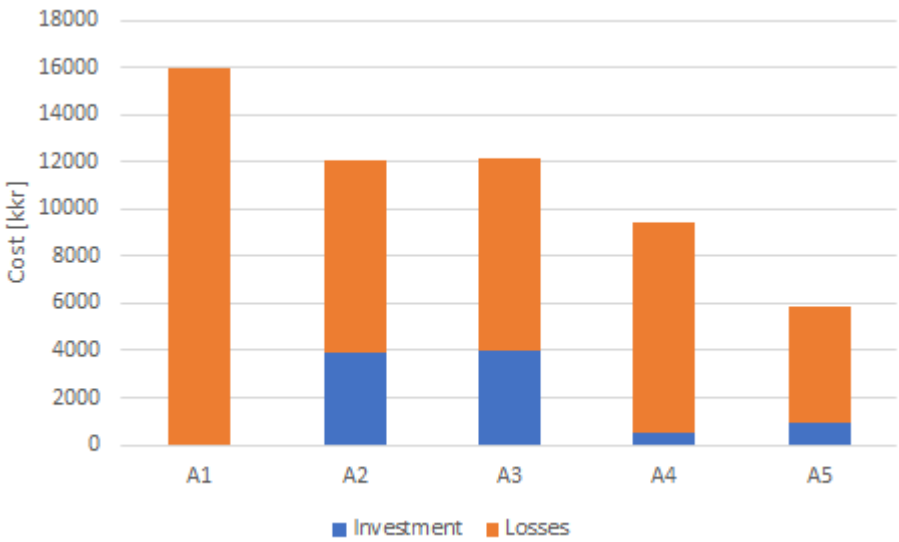

Figure 5.3: Total cost location A for the critical battery price 90 kr/kW

Figure 5.2 shows that alternative two is the cheapest alternative if the charging station shall operate as desired in all hours, while the price is almost halved if reduced power supply because of the application of smart power management. Figure 5.3 shows that the total cost of the battery system needs to be 90 kr/kW for the third alternative to be price competitive to alternative two. The fourth alternative will then have a lower total cost, but that alternative is not technically feasible.

5.1.4 Interruption costs

Figure 5.4 shows the distribution of the different customer groups for the whole transformer and Figure 5.5 for the radial where the charging station is placed. The percentage values are based on the total power usage in the reference hour.

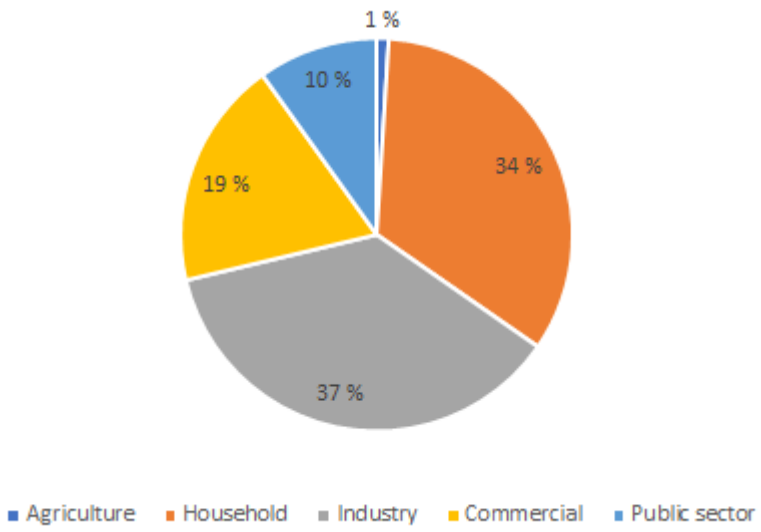

Figure 5.4: Distribution of the different customer groups for the transformer in location A

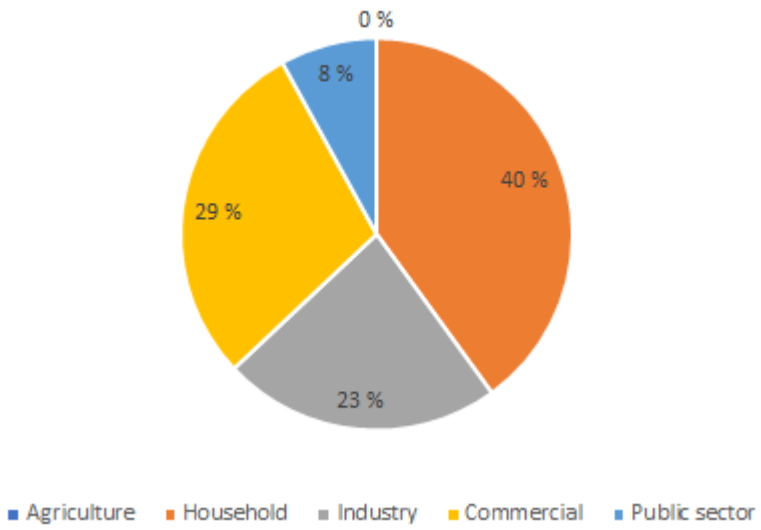

Figure 5.5: Distribution of the different customer groups for the radial in location A

From Figure 5.4 one can see that 34% of the customers of the transformer are household

customers, the group with the lowest interruption cost in the reference hour. Figure 5.5 shows that there are 40% household customers in the radial with the charging station. This gives approximately the same cost of interruption, 102 kr/kW per hour for the transformer and 102.1 kr/kW for the radial. Since there is more power consumption in the whole transformer than in the radial only, the total cost of an interruption is 973.8 kkr/hour for the transformer and 477 kkr/hour for the radial.

5.2 Location B

The transformer station used in this location had 6 MW available in the peak load hour in 2017. The high voltage distribution grid has a voltage level of 22 kV.

5.2.1 Alternatives

Table 5.4 shows the upgrades for the different alternatives in location B.

Table 5.4: Alternatives location B

	Power lines	**Transformer**	**Battery**
A1	-	-	-
A2	3x1x400 Al	Yes	-
A3	3x1x400 Al	-	3 MW
A4	-	-	6 MW
A5	-	-	-

Table 5.4 shows that the transformer is only upgraded in alternative two and that the power lines is upgraded to the cross-section 3x1x400 Al in alternative two and three. There is not performed any upgraded except from the battery in alternative four, and nothing but the smart management system in alternative five.

5.2.2 Technical details

Table 5.5 shows the technical details for the different alternatives for location B.

Table 5.5: Technical details location B

	0	**1**	**2**	**3**	**4**	**5**
Peak losses [kW]	349	420	368	387	367	375
Annual losses [MWh]	1385.1	1648.4	1495.8	1529.9	1466.0	
Load cable	49.0	68.2%	53.8%	49.9%	48.3%	48.3%
Load transformer	101.2%	139.0%	91.6%	127.3 %	115.9%	119.7%

Table 5.5 shows that the first alternative is not technically feasible, while the peak losses are approximately the same for the four other alternatives. Alternative two is the only alternative without any overload for the transformer, but since the peak load occurs in January when the ambient temperature is low, all alternatives are considered as feasible for this location. Alternative five will result in reduced charging power some periods during the year, Figure 5.6 shows the curve of the charging power with and without a smart charging management system in a weekday January and July for this location.

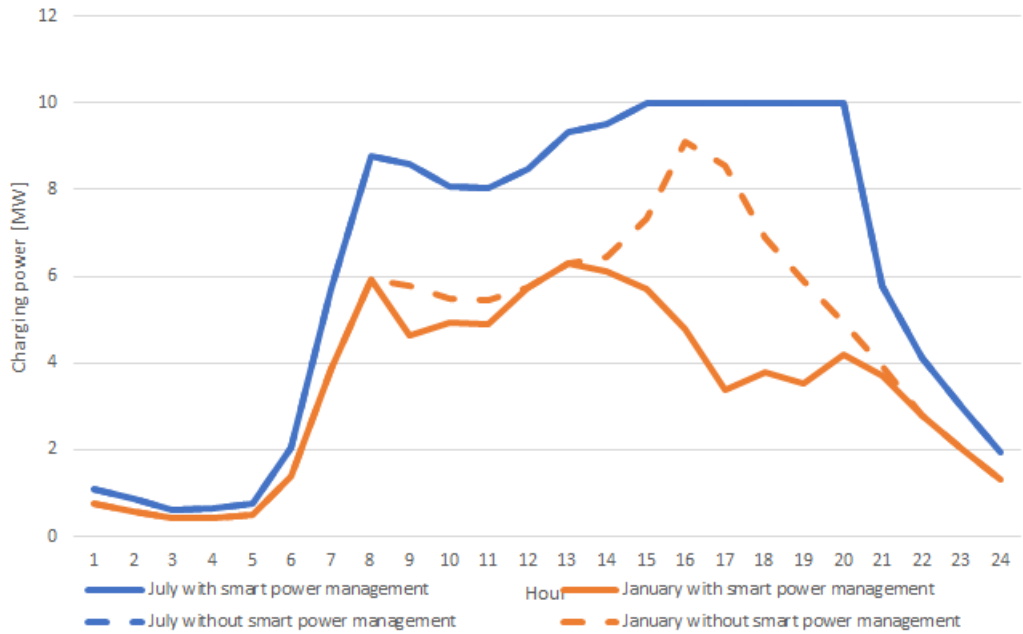

Figure 5.6: Available charging power with and without smart power management for location B

Figure 5.6 shows that the charging power will be at the desired level in July, while it will be around 70% of what it should in January. This means that the smart power management system will not generate any extra queues in July, but it will require that some of the charging is postponed to after eight in the evening in January.

5.2.3 Economical aspects

Table 5.6 shows the investment costs and the total cost of losses for the different alternatives. As the battery price is an unknown factor, it is represented by the letter B in the table. For alternative two and three, that includes an upgrade of the cable dimension, the total length from the transformer to the charging station is 0.76 km. The terrain is considered as suburban.

Table 5.6: Costs location B

	0	**1**	**2**	**3**	**4**	**5**
Investment cost [kkr]	0	0	3,277	620 + B	B	0
Total cost of losses [kkr]	1,354	1,838	1,617	1,511	1,450	1,580

Table 5.6 shows that alternative two has the highest cost of losses, while alternative four has the lowest. Figure 5.7 shows the total costs for all alternatives when the battery price is 2400 kr/kW and Figure 5.8 shows that the battery price needs to be 1030 kr/kW to give an equal total cost for an alternative with and without a battery.

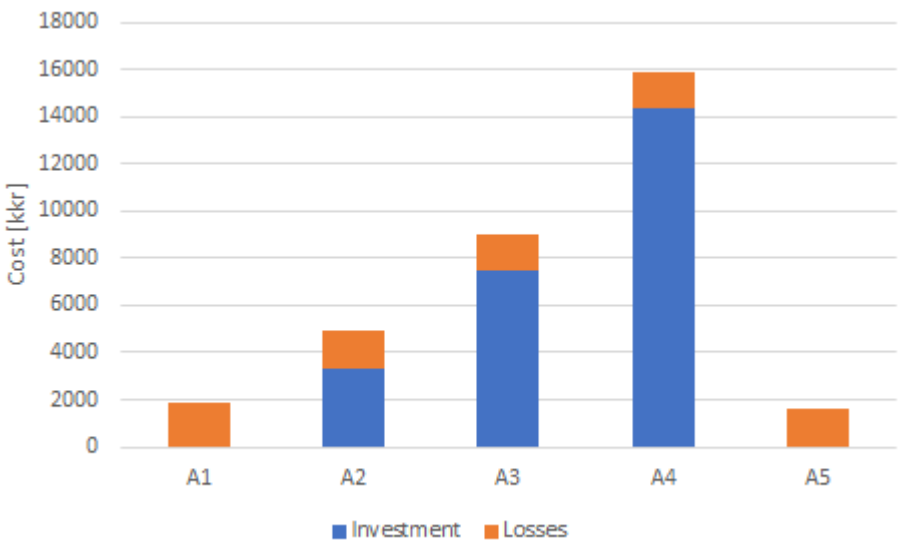

Figure 5.7: Total cost location B when the battery price is 2400 kr/kW

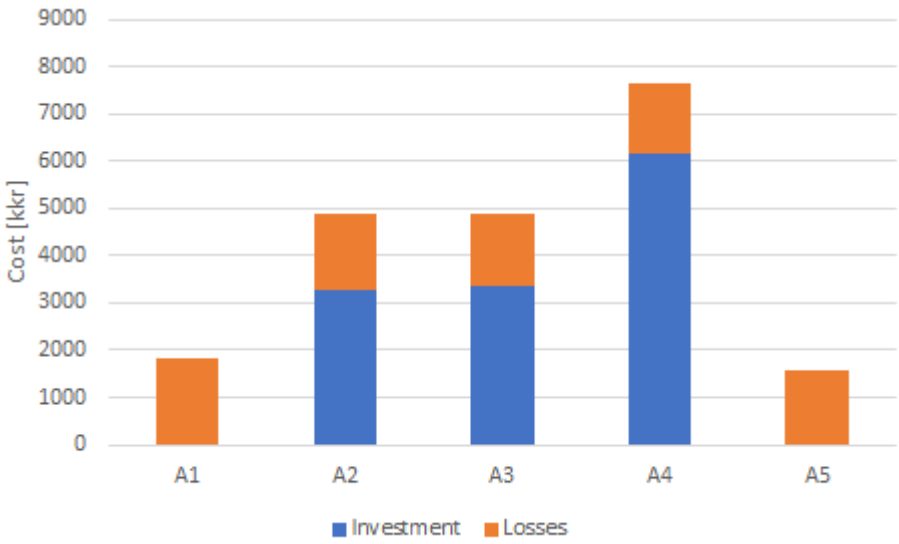

Figure 5.8: Critical battery cost location B, battery cost 1030 kr/kW

Figure 5.7 shows that alternative five, with smart power management, has the lowest total costs, as the investment costs are considered to be zero. This alternative will require that the charging station cannot supply the desired power at all times. Alternative one has the second-lowest costs but is not technically feasible. Alternative two is the cheapest alternative of those that fulfil the technical requirements and the requirements of the charging station when the battery price is 2400 kr/kW. Figure 5.8 shows that the total price of the battery system needs to be 1030 kr/kW for an alternative with a battery to be price competitive to the second alternative.

5.2.4 Interruption costs

Figure 5.9 shows the distribution of the power consumption of the different customer groups for the transformer in location B and Figure 5.10 for the radial with the charging station.

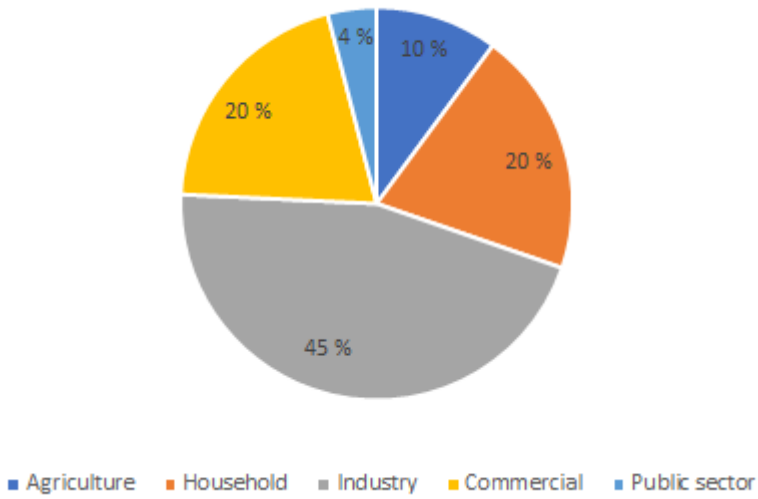

Figure 5.9: Distribution of the different customer groups for the transformer in location B

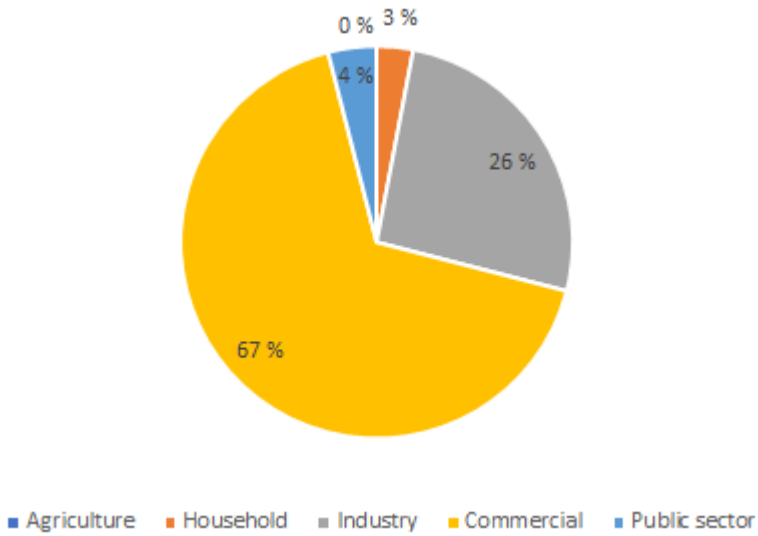

Figure 5.10: Distribution of the different customer groups in the radial in location B

Figure 5.9 shows that 45% of the customers in this location are industrial customers, which makes it the largest group for this transformer. The cost of an interruption per hours is found to be 103 kr/kW, which will be in total 1897.5 kkr/hour for an outage of the whole transformer. The largest customer group for the radial with the charging station is the Commercial category with 67%. As that category is the most costly for an interruption in the reference hour, the cost will be 169.3 kr/kW, in total 562.4 kkr/hour.

5.3 Location C

The transformer station used in this location had around 9 MW available power during peak load in 2017. The nominal voltage on the low voltage side of the transformer is 11 kV.

5.3.1 Alternatives

The alternatives for location C is shown in Table 5.7.

Table 5.7: Alternatives location C

	Power lines	**Transformer**	**Battery**
A1	-	-	-
A2	3x1x630 Al	Yes	-
A3	3x1x240 Al	-	3 MW
A4	-	-	6 MW
A5	-	-	-

Table 5.7 shows that the only upgrades in this locations is the power lines in alternative two and three.

5.3.2 Technical details

Table 5.8 shows the results from the technical analysis for location C.

Table 5.8: Technical details location C

	0	**1**	**2**	**3**	**4**	**5**
Peak losses [kW]	223	576	342	370	300	354
Annual losses [MWh]	1010.3	2619.4	1530.9	1655.6	1341.8	
Load cable	37.2	201.1%	79.5%	84.4%	88.8%	117.8%
Load transformer	66.3%	105.9%	104.6 %	93.2 %	81.5%	87.7%

Table 5.8 shows that the problem in this location is the loading of the cables, where the most loaded cable will be loaded more than 200% in alternative one, making this alternative not feasible. All the other alternatives are technically feasible, and the loading of the cable is decisive for how the smart power management system regulates the power flow to the charging station. Figure 5.11 shows how the available power on the charging station will be if a smart management system is applied for a weekday in January and July.

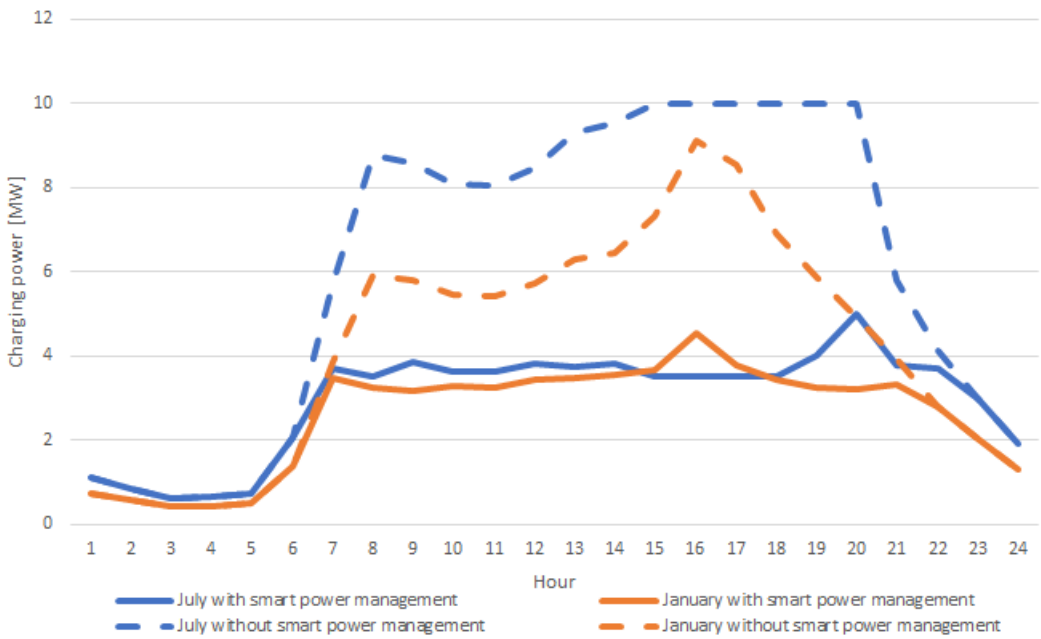

Figure 5.11: Available charging power with and without smart power management for a weekday in January and July in location C

Figure 5.11 shows that the available power for the charging station will be approximately 40% of the desired value in both January and July.

5.3.3 Economical aspects

Table 5.9 shows the costs for the different alternatives in location C. As the battery price is unknown, it is represented by the letter B in the table. The total length of the cables to be upgraded in alternative two and three is 3.042 km.

Table 5.9: Costs location C

	0	**1**	**2**	**3**	**4**	**5**
Investment cost [kkr]	0	0	1,420	987 + B	B	0
Total cost of losses [kkr]	555	9,991	2,886	4,199	2,422	3,449

Table 5.9 shows that the total cost of losses is very variable for the different alternatives. Alternative four has the lowest cost while alternative three has the highest. The total cost depends from the battery price. Figure 5.12 shows the total cost when the battery price is 2400 kr/kW and Figure 5.13 shows the situation when the battery price is 314 kr/kW, sufficiently low to be price competitive to the traditional reinforcement.

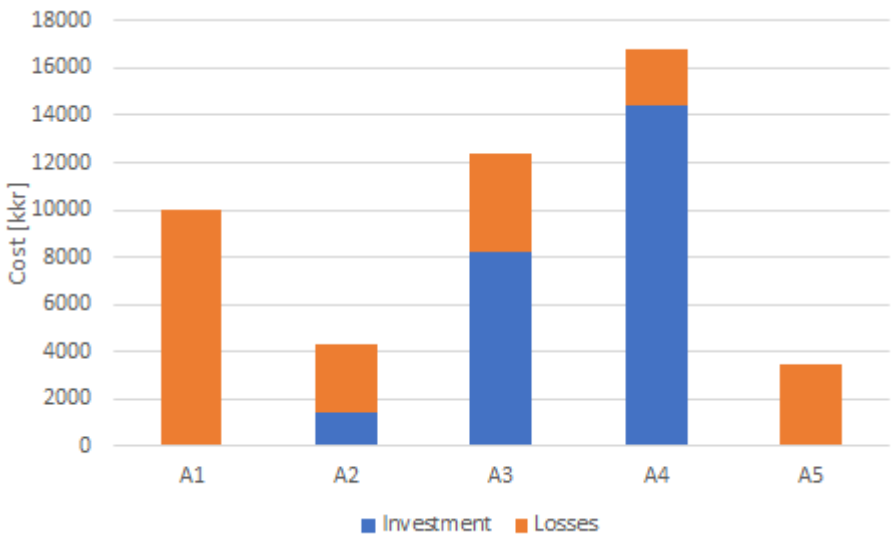

Figure 5.12: Total cost location C when the battery price is 2400 kr/kW

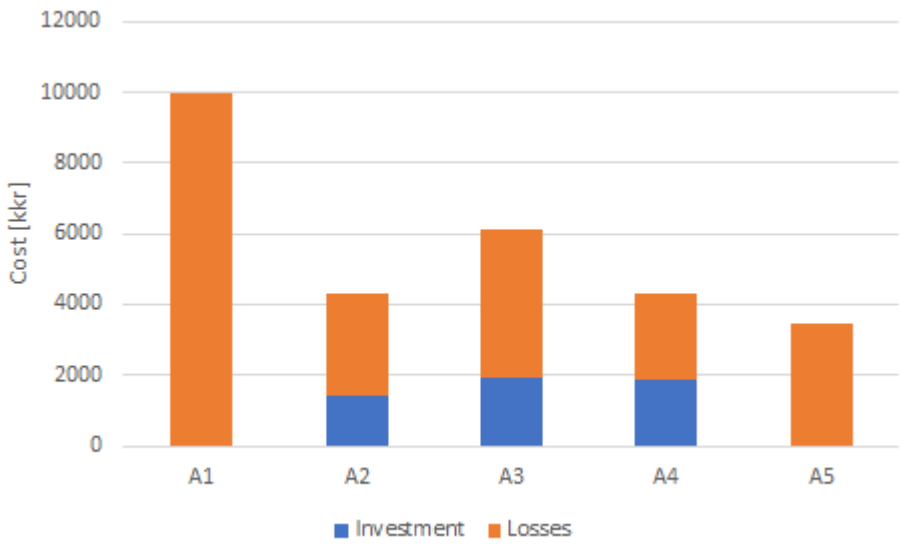

Figure 5.13: Total cost location C when the battery cost is 314 kr/kW

Figure 5.12 shows that the alternative with smart power management has the lowest total cost when the battery price is 2400 kr/kW, but alternative two is not much more expensive, even if it can supply the charging station with more power. The battery price needs to be 314 kr/kW to make alternative four price competitive to alternative two.

5.3.4 Interruption costs

Figure 5.14 shows the distribution of the power for the different customer groups for this transformer and Figure 5.15 for the radial with the transformer.

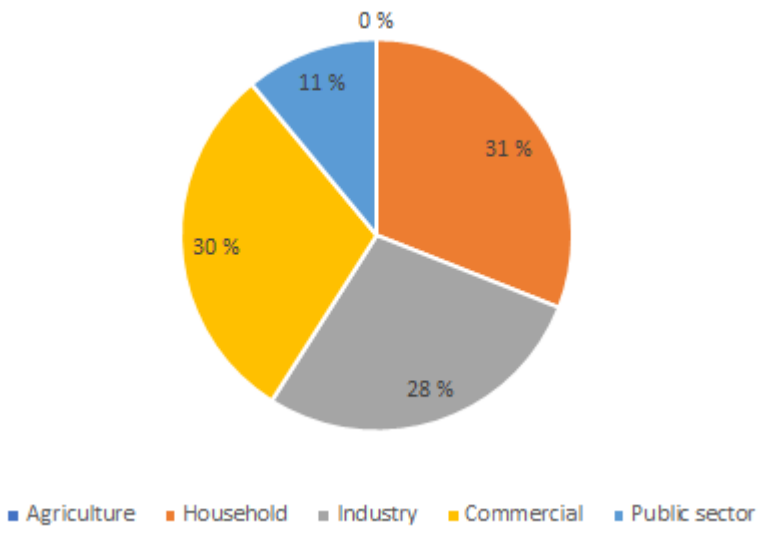

Figure 5.14: Distribution of the different customer groups for the transformer in location C

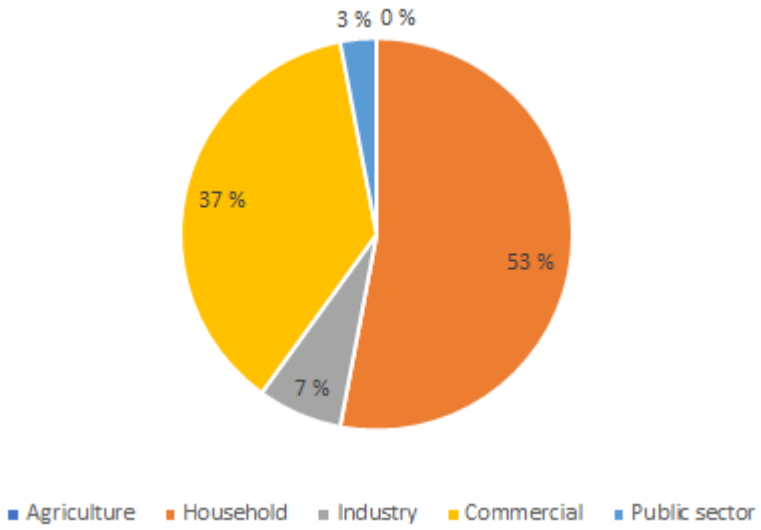

Figure 5.15: Distribution of the different customer groups for the radial in location C

The power consumption for the customer groups household, industry and Commercial

are approximately the same for this transformer station, giving a cost of 114.2 kr/kW per hour for this transformer station, 1481.8 kkr/hour in total. More than 50% of the customers in the radial with the charging station are household customers, which reduces the cost of an interruption to 91.7 kr/kW and gives a total cost of a one-hour interruption of 246.4 kkr.

5.4 Location D

The transformer station in location D consists of three transformers, where around 30 MW was available from this transformer station during peak load in 2017. The voltage level of the low voltage distribution grid is 11 kV.

5.4.1 Alternatives

Table 5.10 shows the different alternatives for location D.

Table 5.10: Alternatives location D

	Power lines	**Transformer**	**Battery**
A1	-	-	-
A2	3x1x630 Al	Yes	-
A3	3x1x400 Al	Yes	3 MW

Table 5.10 has only three alternatives, as the options to avoid a transformer upgrade is not possible for this location.

5.4.2 Technical details

Table 5.11 shows the results from the technical analysis on location D.

Table 5.11: Technical details location D

	0	**1**	**2**	**3**
Peak losses [kW]	1089	1590	1143	1146
Annual losses [MWh]	4182.5	6246.5	4606.2	4510.9
Load cable	87.9	266.0%	130.4%	104.8%
Load transformer	134.6%	171.6%	95.7 %	91.2 %

Table 5.11 Shows that the load level of both the transformer and the power lines is too high in alternative one, making it unfeasible. The load level of the cable in alternative two is also high, but it can still be feasible.

5.4.3 Economical aspects

Table 5.12 shows the costs of the different alternatives. The investment in alternative three includes a battery, where the cost of that is represented by the letter B in the table. Both alternative two and three includes reinforcement of both the transformer and the power lines, where the total length to be upgraded is 2.761 km.

Table 5.12: Costs location D

	0	**1**	**2**	**3**
Investment cost [kkr]	0	0	4,281	4,011 + B
Total cost of losses [kkr]	4,066	15,629	6,566	6,474

Table 5.12 shows that the loss cost of the two technical feasible alternatives are approximately the same, where alternative three is the cheapest. The total cost of alternative three depends from the battery price and Figure 5.17 shows that the battery price needs to be 120 kr/kW to be price competitive to alternative two. Figure 5.16 shows the situation when the battery price is 2400 kr/kW.

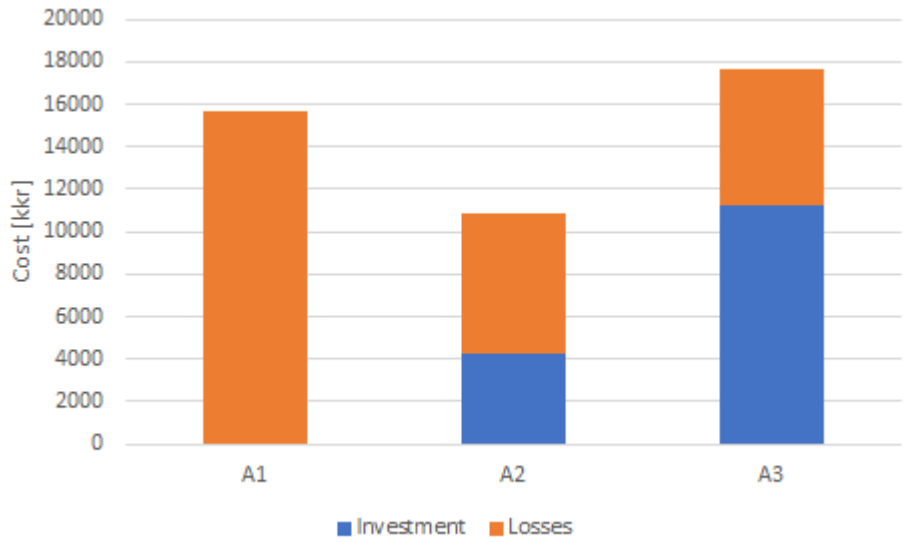

Figure 5.16: Total cost location D when the battery price is 2400 kr/kW

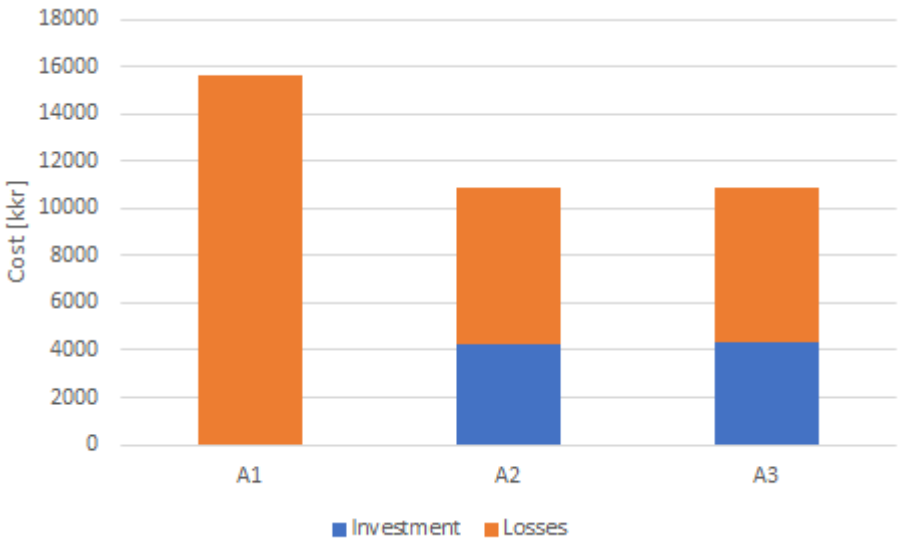

Figure 5.17: Total cost location D when the battery price is 120 kr/kW

Figure 5.16 shows that the total cost of alternative two is approximately two-thirds of the total cost of alternative three when the battery price is 2400 kr/kW. Figure 5.17 shows that the total price of the battery system needs to be 120 kr/kW to be price competitive to the alternative without a battery.

5.4.4 Interruption costs

Figure 5.18 shows the distribution of the total power from the transformer station amongst the different customer groups. Figure 5.19 shows the distribution within the radial with the charging station.

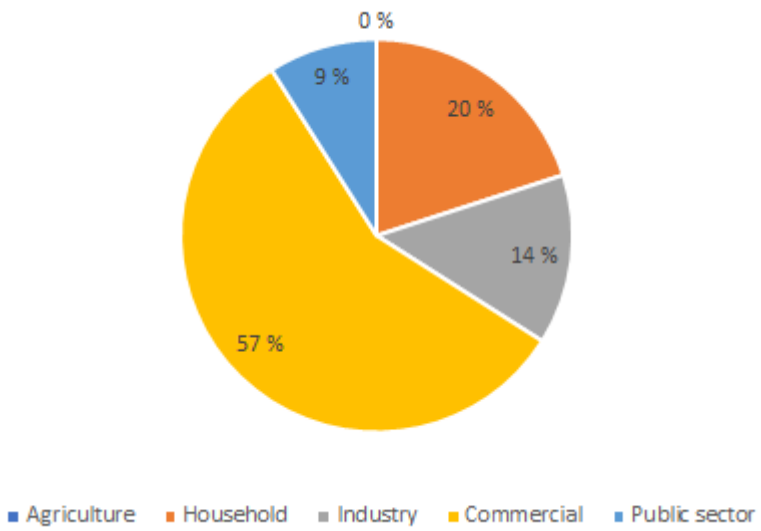

Figure 5.18: Distribution of the different customer groups for the transformer in location D

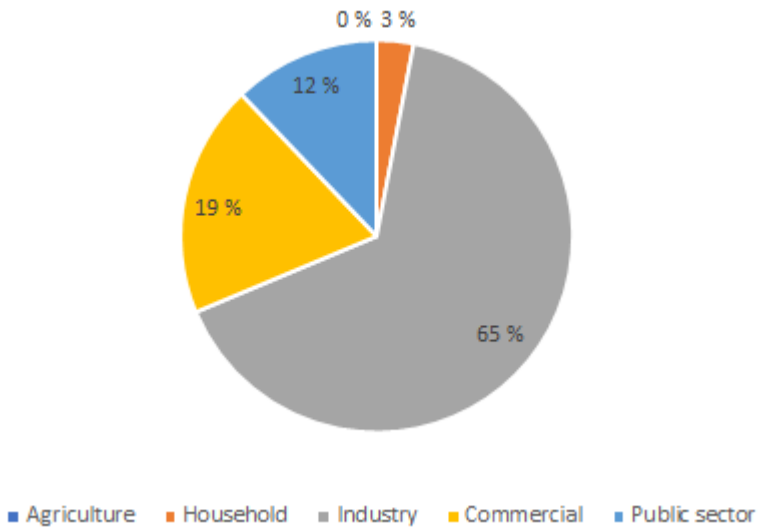

Figure 5.19: Distribution of the different customer groups in the radial in location D

Figure 5.18 shows that 57% of all the power from the transformer in the reference hour goes to the Commercial group, the most expensive for an interruption in that hour. This gives a cost of 145.9 kr/kW for one hour, resulting in 4807.9 kkr for the whole transformer. For the radial with the charging station is 65% used by the industry category, which has

a lower cost for an interruption than Commercial. This gives 135 kr/kW for a one-hour interruption, in total 694.8 for a one-hour outage for the radial.

5.5 Evaluation of the locations

This section will give an evaluation of the different locations. This cannot be measured economically, but it may be important to see if some of the locations are unacceptable because of the geographical location.

Figure 5.20 shows the alternative locations for the charging stations.

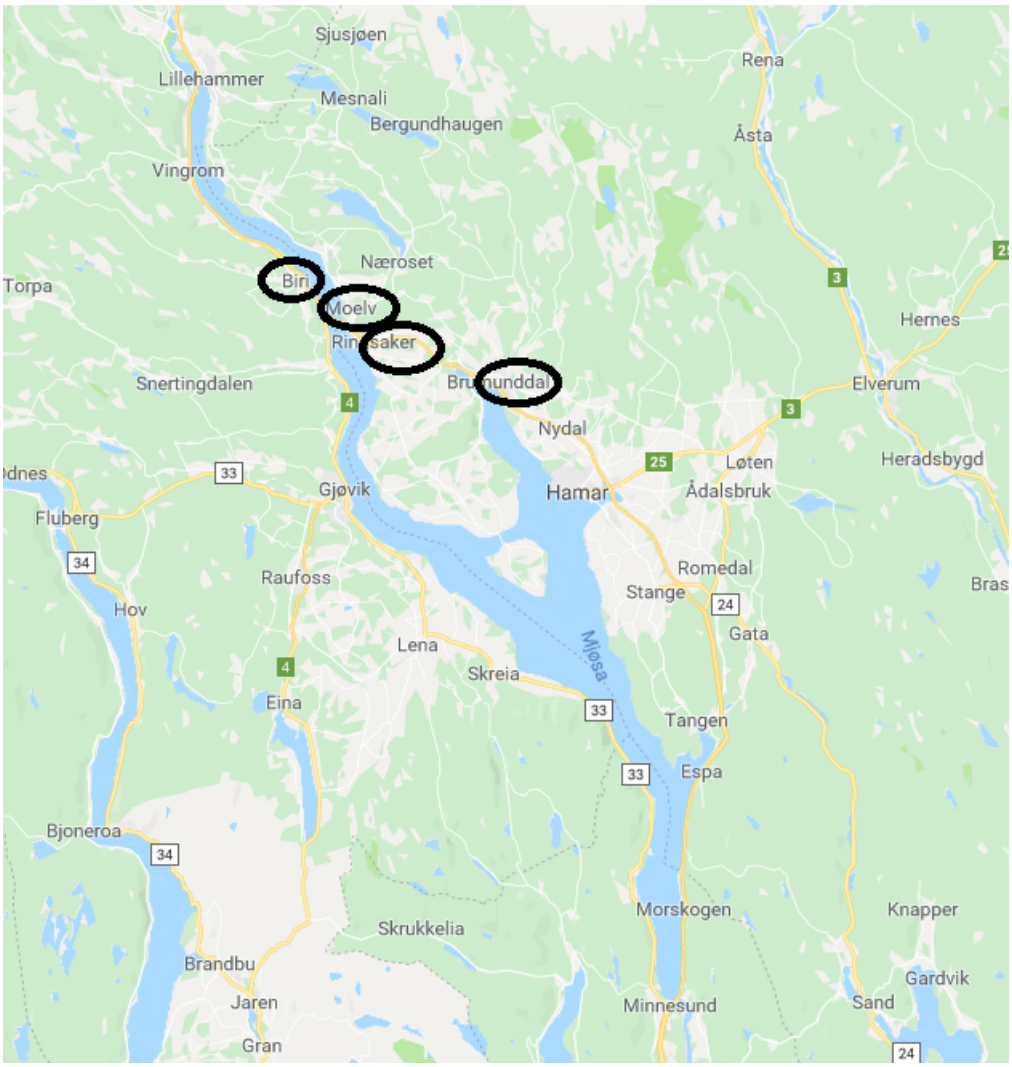

Figure 5.20: The location of the charging stations

As shown in Figure 5.20, the four locations are Brumunddal, Rudshøgda, Moelv and

Biri. It is 139 km from Oslo to Brumunddal, 148 km to Rudshøgda, 155 km til Moelv and 161 km to Biri. This means that all these locations except Biri fulfil the recommendation from Elbilforeningen with one large charging station every 150 km along the main roads in Norway if the last charging station is situated in Oslo. There is already established the largest charging station in Europe at Nebbenes in Akershus [52], which is only 98 km south of Biri, and it is reasonable to think that this station will be upgraded further and then be one of the large charging stations Elbilforeningen recommends. This makes all of the alternatives presented in this thesis feasible when it comes to the distance between the charging stations, where Biri maybe will be the best to avoid that the charging stations will be too frequent. If a charging station is established in Biri, the next one have to be within the next 150 km north of Biri. It is nearly 180 km to Dombås, where Tesla today has 16 superchargers [55]. This means that there is a need for a charging station south of Dombås to make any of the locations presented here possible. There is a McDonald's restaurant as well as a gas station near E6, and near where the charging station is thought to be at Brumunddal, this will make this location attractive to stop and charge the vehicle. There is not so much available space in this location, so if the charging station shall be placed here, it needs to agree with the landowner who owns the farmland nearby. At Rudshøgda there is a cafe and a shopping mall where one can do large grocery shopping when the vehicle is charging. Some of the areas around this location will possibly be affected to realize a large charging station at Rudshøgda, which will require an agreement with the owner of the farmland and the forest around the location. The charging station in Moelv is situated near a Shell gas station, so there are some facilities here today, but that is maybe not enough for a large charging station. The area around the possible charging station consists of houses, which may make it more difficult to use that location for a charging station. At Biri there is today a 24-hour rest stop for freight transport, operated by Statens Vegvesen [49] and can, therefore, be a good alternative as this already is a natural place to stop. There is also a cafe near that stop. Since this is already a truck stop, this is the location with most available space today, but maybe not enough, which means that also this location depends from an agreement with the owner of the farmland to establish a charging station at Biri.

5.6 Discussion of the results

It was performed load flow analysis in Netbas for all alternatives for the four locations. The results of interest in this study were the loading of the transformers and power lines in the peak hour, the peak power losses and the annual power losses. Accurate results require that all parameters in Netbas are correct, which means that the load of every customer should be modelled correctly for all hours during the year. Since it is not hourly measurements

in Netbas, the load in a specific hour is based on the annual energy consumption and the calculation factors as described in the theory chapter. To avoid under-dimensioning of the components due to wrong calculation of the maximum power, the values in Netbas usually is higher than the actual values. There is a possibility of adding current measurements for each of the radials in the transformer to get a more accurate simulation for the peak load hour. There are real current measurements for all transformer stations, and by having this value as an input in Netbas, the software will scale all loads so that the total consumption equals the actual consumption. It will, therefore, be possible to obtain somewhat accurate calculations for the peak load hour. The drawback with this method is that it only works for the peak load hour, as one can either choose to scale the load by the current measurement or from the load variation curve during the year. Therefore it was chosen to use the values in Netbas for all calculations in this thesis, also the peak load. How significant the difference would have been is hard to say, but as there are many other uncertain factors, especially how the load curve of the charging station will be, the method was considered as sufficient for this application.

Figure 5.21 shows the total costs of the different alternatives for the four locations when the battery price is 2400 kr/kW. Alternative one is excluded from the figure as that alternative was unfeasible for all locations.

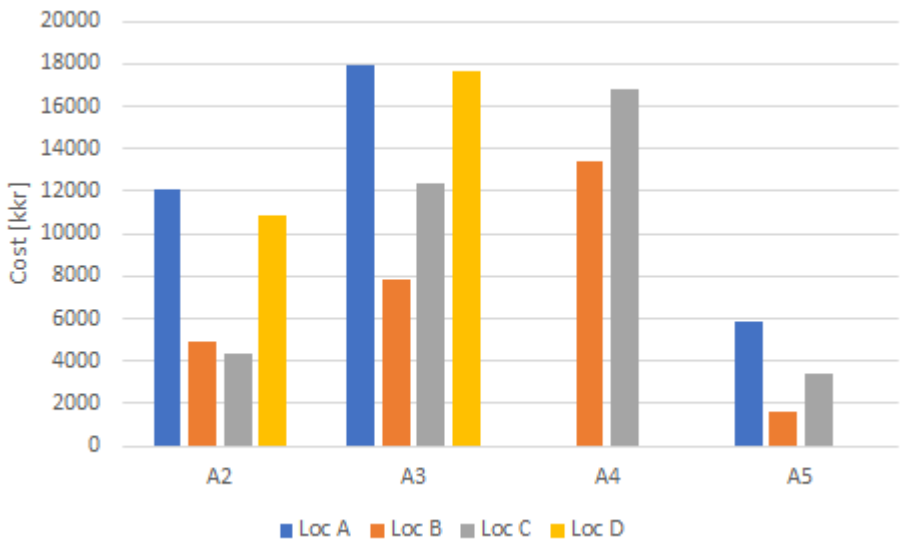

Figure 5.21: Total costs of all alternatives for the four locations when the battery price is 2400 kr/kW

Figure 5.21 shows that location C has the lowest total cost for alternative two, while location B is cheapest for the other alternatives. Location A has the highest total cost for all alternatives, as long as alternative four and five in location D is excluded from the figure

because it did not fulfil the technical requirements. The reason why alternative A has the highest total cost may be the low available capacity in the transformer and that the power lines needed to be upgraded to a large cross-section in all alternatives. The transformer was not upgraded in alternative five, but the total cost of losses was almost the same as in alternative two, giving high total costs compared to the other locations also with smart power management. Location B and C have almost the same total cost for alternative two, but while about two-thirds of the costs are investment costs in location B, one third is investment and two-thirds is losses for location C. This can be seen in Figure 5.22. The reason for that is that both the transformer and the power lines were upgraded in location B, while only the power lines was for location C. In alternative three, there is installed a battery of 3 MW for all locations This reduced the power flow enough to avoid an upgrade of the transformer for location B, making that a cheaper location than location C for that alternative. The same happens in alternative four, where a battery of 6 MW is installed on the charging station; the lower losses in location B gives lower total costs than alternative C. The total costs for alternative four, with smart power management, is the cheapest for all locations, but it cannot supply the desired power to the charging station all over the year for any of the locations, so the product one can have for the price is not competitive to the other alternatives.

Figure 5.22 shows the total cost of the alternative with traditional reinforcement of the grid for the four locations. The alternative with the lowest total costs for all locations, if reduced power with smart power management is not acceptable.

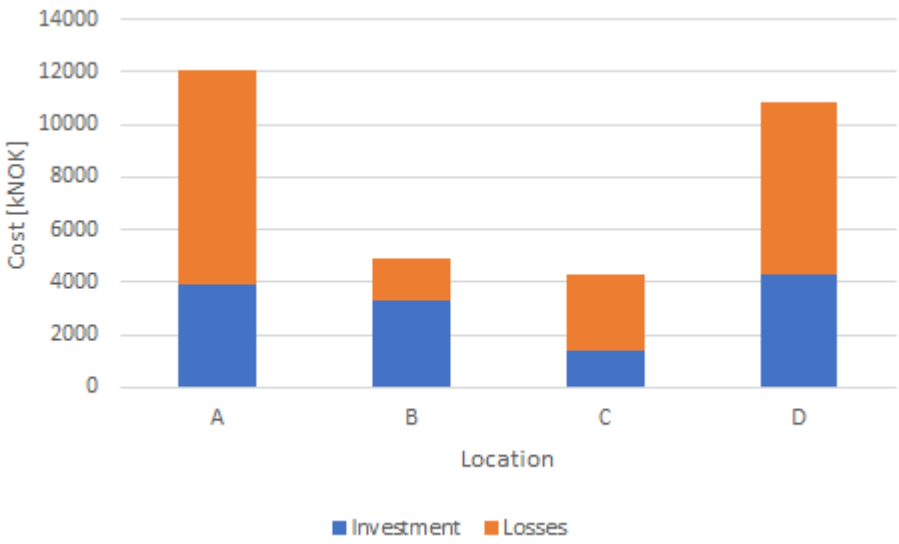

Figure 5.22: Total costs for each location

Figure 5.22 shows that location C is the cheapest location to establish a charging station

with a maximum power of 10 MW. The cost of location B is not so much more expensive, and the cost of losses is lower in location B. The cost at location A and D is more than twice the cost in location C and B. Location B is the only location where the high voltage distribution grid is 22 kV, which gives higher available power with less current flow in the cables. New cables on that voltage level are more expensive than cables with a nominal voltage of 12 kV, giving higher investment costs, but lower costs of losses. If one wants to establish a charging station in one of the four locations, and the only concern is the total cost over the first ten years, location B and C will be the definitive best locations.

Figure 5.23 shows that the maximum charging power available during a weekday in January for each location of a smart power management system is applied. Location D is not in the figure, as the smart power management was not technically feasible in that location.

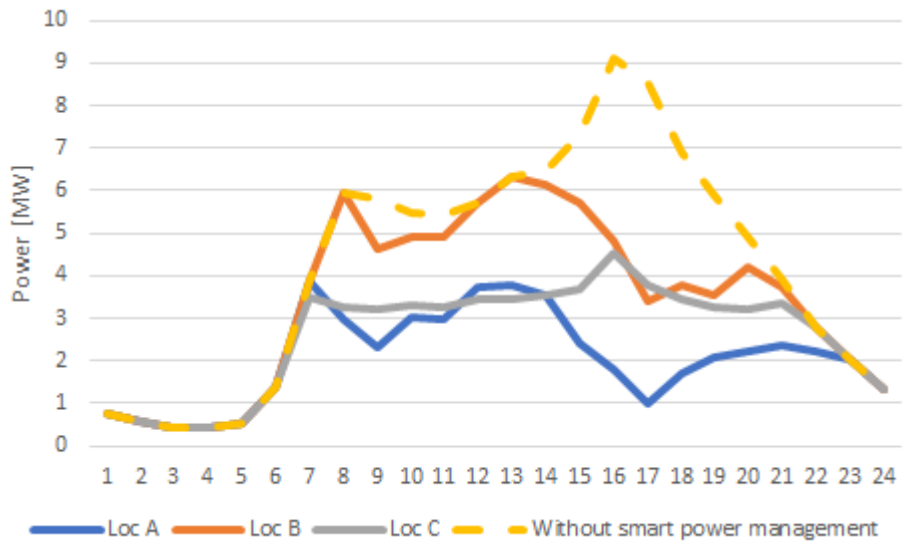

Figure 5.23: The maximum available charging power during a weekday in January for location A, B and C. The dotted yellow line corresponds to the desired charging power.

Figure 5.23 shows that location B will have the highest possible charging power during the day with peak load in January. Location A and C will have almost the same peak power until 17 in the evening when location C has more available power for charging. Location C has a more stable charging power throughout the day than location A and has nearly the same power as location B in the evening. For a charging station that should have an available power of 10 MW at all times, one can see that it will be much lower charging power for all the locations, which will lead to longer charging times and long queues at the charging station. As the power is up to 60% of what it should be in location B, the solution can be feasible, but it will require much more patience from the end-user

and as a consequence lead to less sale of EVs. With charging power under 4 MW most of the day in location A and C, the cars need to be charged during the night if the total energy need from this charging station shall be covered. Then most EV-owners will maybe either charge less on that fast charging station or not charge there at all, but charge at home instead. However, there is a reason why Elbilforeningen has the recommendations for fast charging stations, which means that solving this problem by home charging is not a realistic alternative. From Figure 5.21, one can see that the total cost of the smart power management alternative in location A is nearly half the price as the alternative of upgrading all power lines and the transformer. The total costs of the smart power management for location C is almost 1 million, around 20% less than alternative one, even though there was an investment in alternative one, and that alternative one can supply the charging station with 10 MW anytime during the year. Location B is the location where the price difference is biggest, and the available charging power with smart power management is highest, which means that this actually can be an alternative solution here.

Figure 5.24 shows the cost of an interruption in the reference hour caused by the charging station for the four locations.

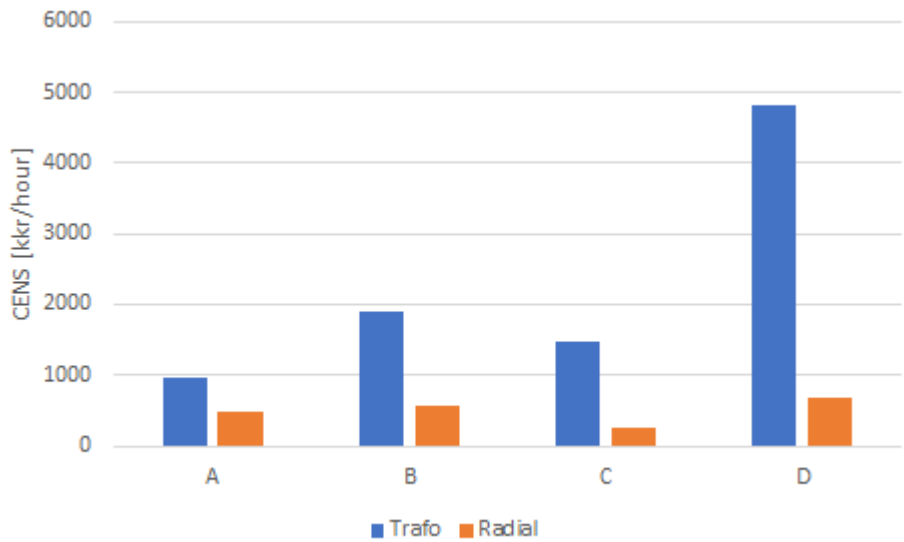

Figure 5.24: CENS in kkr/hour for the four locations

The costs for an interruption caused by the charging station in the reference hour is only to compare the different locations, as it the probability for an hour interruption for a whole transformer or even a radial is small. The cost of the energy not supplied to the charging station is not included for any of the locations, as it will be the same for all of them. It would have been interesting to see complete probability analysis for the different locations, to see how a battery in the grid will affect the reliability, for example. There

is, of course, a probability for the other components than those related to the charging station to fail too, which will be higher for some locations than others. This is a complex calculation and is not a part of this thesis. Therefore, the cost of the energy not supplied cannot be added to the total costs for the different alternatives. Figure 5.24 shows that location D has the highest costs of an interruption both for the transformer and the radial with the charging station. This is because of all the customers in the Commercial category and that there is much more power supplied by that transformer than the transformers in the other locations. Location C has the lowest interruption costs for the radial with the charging station because of the high share of household customers compared to the other locations and also less total power than the others. Location A has the lowest interruption costs for the whole transformer since there are many household customers and low power consumption in total from that transformer. One can see that the cost of an interruption in the whole transformer in location A is not much higher than an interruption only for the radial with the charging station, even if the total power from the transformer is twice the power in the radial only. The radial with the charging station in location B has the highest interruption cost per hour, 169 kkr/hour compared to 102 kkr/hour in location A, 91.7 kkr/hour in location C and 135 kkr/hour in location D. So when it comes to CENS, location A will be the location with the lowest interruption costs overall, while location D will be the worst.

5.7 Optimal location

The technical and economic analysis shows that alternative two in location C will have the lowest total cost for this analysis period, followed by the same alternative in location B, as long as the total price of the battery system is more than 1030 kr/kW for all locations. Alternative B has the lowest cost of applying the smart power management system and has, besides, the most available charging power of all locations. The interruption costs cannot be added to the other costs, as the probability for an interruption during the analysis period is not calculated. As the cost depends from how probable failure is, it is hard to say how much the CENS will affect the total cost, and how decisive that factor should be when choosing the optimal location for a charging station. What can be seen is that location A has the lowest interruption costs for both the transformer and the radial with the charging station, but since that location is one of the most costly to upgrade, it is considered not to be the optimal location. Location C has the second-lowest interruption costs both for the transformer and the radial, and in combination with the lowest costs for the alternative with traditional reinforcement, this can be seen as the optimal location. Location B will be the optimal location if reduced charging power in the busiest hours during the year is accepted, but to the requirements of the charging station, location C will be the optimal

location for a charging station. From the evaluation of the location, it was found that the differences between the four locations were not very large, as all of them had some facilities today, and that the distance between them is short, meaning that it does not matter that much which of them to choose. The conclusion after applying the method on the four locations in this thesis is, therefore, that location C will be the optimal location for a fast charging station.

Chapter 6

Discussion

6.1 Discussion of the initial conditions

There are many uncertainties for future grid planning, as one does not know how the energy consumption will change, or if it will change. The assumption for the electrification of the transport sector made in this thesis may be somehow correct, but as it is a sector going through a significant change both technologically and the use of it, it is tough to anticipate the power need from the transport sector in the future.

The maximum capacity and the charging profile will depend from each other, and it is maybe a more natural way to calculate the maximum available power for the charging station from the charging profile over the year and not the opposite as in this thesis. The reason why it was done is that there is a lack of data and good forecasts for the use of charging stations available. Even if Elbilforeningen recommends 10 MW for all the charging stations along the main roads in Norway, it does not necessarily mean that it is the demand everywhere. The need for a charging station will depend on the share of EVs and how the development on the other vehicles in the land transport sector will be. If the EV sales slow down and all freight transport will be running on hydrogen in the future, the need for the charging station described in this thesis will not be very high. It might be that the lack of good charging possibilities slows down the electrification of the transport sector, so there is no option to wait and see how it will be. If one looks at a scenario where all vehicles on the road are electric, one approach is to calculate the total energy to the transport sector from the number of litres of gasoline sold at the gas stations today and convert it to the electricity demand from charging. The weakness in this approach is that it is hard to differentiate between home charging and fast charging, as all the energy used by conventional vehicles comes from the gas station, while that most probably not will be the situation when some of the charging, or maybe most of it, will be done at home. This means that the actual need for charging is an uncertain factor that needs to be estimated

in a way, but even if it generates more investment costs, it may be better to design an oversized charging station to not be the factor that slows down the electrification.

Figure 6.1 shows the load curve during a year for a standard load compared to the load curve of the fast charging station found in this thesis.

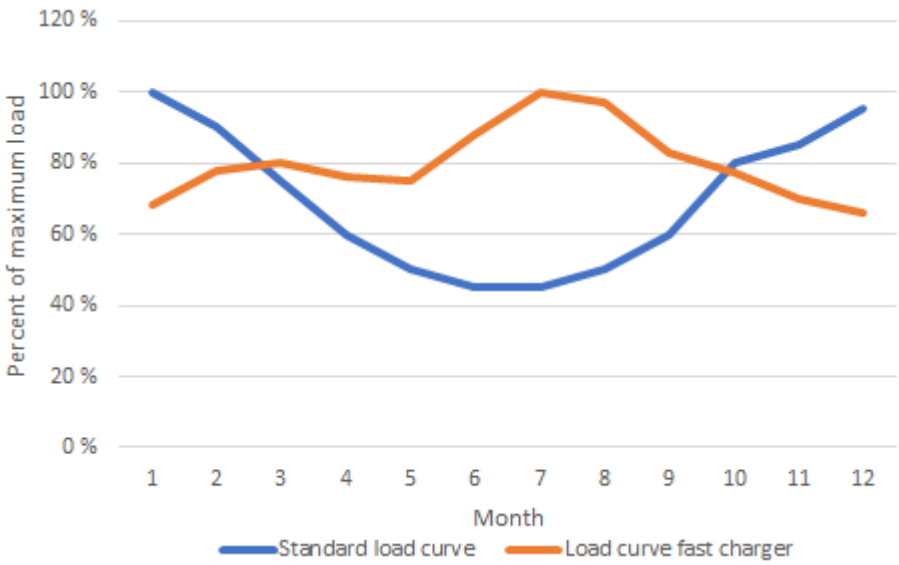

Figure 6.1: The load curve for standard loads in Netbas compared to the load curve for the fast charging station

From the curve in Figure 6.1 one can see that the minimum load for the curve of the charging station occurs in January when there is a peak on the standard load variation curve. The opposite occurs during the summer months when the charging curve has its maximum, and the standard load curve has its minimum. This shows how important it is to have the correct load profile as the input in this model. There are load profiles that are different from the one in the figure in Netbas, for example for industry with less load during the weekends than in the weekdays, but the trend is that the maximum power consumption occurs during the winter due to space heating. That these curves have their maximum in different months will be an advantage for the grid, as it possibly can make the power consumption during the year more constant. If the charging station is modelled as a standard load, it will lead to an over-dimensioning of all the components in the grid, which is not beneficial. As the power consumption of an EV is higher in cold ambient temperatures, the need for charging will be larger during the winter than in the summer. The charging power is also reduced in cold temperatures, which will prolong the charging time and possibly generation a queue on the charging station. It is hard to say which of these effects that will affect the charging pattern during the winter the most, or if they will affect it at all. If the charging station can operate with the same charging power

also in cold weather and the EVs needs to be charged more often, the load curve would maybe be evener. That Netbas only differentiates between weekday and weekend during high load and low load, might be a problem in the future, not only for charging stations, but also other loads. As seen from the data from the traffic counting, there is a significant difference between a Monday evening and a Friday evening, and also between a Saturday and Sunday. A new planning method will, therefore, require better options for load profiles in the simulation software.

The requirements for the security of supply will be very decisive for the total cost both of the investment and the operation of the charging station. This factor should be a standard for all charging stations in Norway, so it should maybe not be a concern for every charging station to be planned. To have a situation where all the power to the charging station is switched off during a fault, is not a good idea, as the need for this charging station is there for a reason, and there will be large consequences for the society if the charging station suddenly shuts down. If there is a standard for all charging station for this, the charging will be more predictable for the end-users, as they know if an outage time should be expected and how often for all charging stations.

The election of the locations for the analysis in this thesis was based on the capacity on the transformers nearby and the distance from the transformer to E6 and the possible charging station. This is a good approach as long as there are transformer stations with free capacity close to the road if not, an alternative of establishing a new transformer station could be considered. Then the transformer station could be built only for the charging station, which will not affect any other customers in the distribution grid in any way unless an overload or failure in the charging station has consequences for the regional grid. The same yields the other way, none of the other customers can affect the reliability of the charging station unless there is something wrong in a higher grid level.

Cooperation between the DSO and the company that want to establish a charging station will be necessary to make the best out of the model. From the traditional method where the owner of the charging station will be responsible for suggesting a location, this method will require that someone with knowledge about the available capacity in the grid to choose the location.

6.2 Discussion of the alternatives

6.2.1 Alternative 1 - Zero alternative

The alternative of doing nothing in the grid, but establish a charging station that is expected to operate in a good way all over the year, was an optimistic alternative, and as expected it was not technically feasible in any of the locations. Even if there was enough capacity in total for some of the locations, the structure of the radials resulted in an over-

load of the transformer for all of them. The method says that once there is a violation of the technical requirements, the alternative shall be modified without performing economic analysis. Despite that, it was performed anyway, to see that an alternative with a high overload of the transformer generated high costs of losses too. Even if this alternative was not feasible for any of the locations in this thesis, it might be possible in other locations and is therefore good as a first alternative, as it will be the cheapest as long as the power losses are not very high.

6.2.2 Alternative 2 - Traditional reinforcement of the grid

This alternative is the most secure for a good operation of the charging station, as the grid can be upgraded as much as needed until it is feasible for all locations. All the cables were upgraded to the same dimension for each location with this alternative. The distance from the transformer station to the charging station is relatively short for all locations and the load at the charging station is so high compared to the rest of the load. Therefore, it might be a good approach, but it can be that a solution with a bigger cross-section the first part and then a smaller can be possible. This alternative turned out to be the alternative with the lowest total cost for all locations, which may be correct, but it does also depend much from the cost of the battery used in alternative three and four.

6.2.3 Alternative 3 - Upgrade the grid to 70% of the peak load, and install a battery to cover the last 30%

This alternative required in most cases investments in the grid, even if the peak load for the grid was reduced from alternative two. The calculation of the investment cost shows that the price difference for two different cross sections on power cables is not that much, as the cost for the work is a huge part of the total cost. As over-dimensioned power lines will lead to reduced power losses and therefore reduced total cost, it might be the best alternative to upgrade to the largest cross-section regardless if an upgrade is necessary. The exception is if the battery is price competitive to the reinforcement so that the total cost of this alternative will be lower. This alternative can be a smart alternative since the use of the charging station is an unknown factor and might change during the lifetime of the cables. The battery can also be used as a power reserve for the charging station, that will guarantee 3 MW even during an interruption in the grid, as long as the battery is fully charged when the fault occurs. If there are customers in the grid with higher priority during an interruption than the charging station, the battery can also be used to increase the security of supply for those customers. The charging of the battery will give a higher load in the off-peak hours for the charging station, and will probably give an equal distribution of the load, that can be an advantage for the grid, as long as the capacity of

the battery is large enough to be recharged during those hours.

6.2.4 Alternative 4 - Install a battery at the charging station to avoid reinforcement

This alternative will require much from the battery, and for some locations more than what is possible, as the situation in location D. The total energy that the grid can supply to the charging station and the battery without any supply needs to be large enough to cover the demand, as the energy to the battery needs to come from somewhere. If the demand is more than 8 MW 12 hours during one day, but the grid only can handle 2 MW without any upgrades, it will be hard to get a battery with large enough storage capacity and the possibility to recharge fast enough. The cost of the losses will for this alternative be much higher than what was found in the previous chapter, as that did not include the power flow for recharging the battery. If such a battery exists, the solution might be very costly, and therefore not feasible economically. If the grid is strong enough to handle an increment without any upgrades, and the battery solution is both theoretically possible and economically feasible, it might be a good solution to postpone an upgrade of the grid if the load is expected to increase in the following years, or to be used as a flexible resource in the grid as in alternative three.

6.2.5 Alternative 5 - Smart power management

This alternative requires that there is some available capacity in the transformer, so it does not need to be upgraded anyway. The requirement for the charging power during the day and year may be disobeyed in this alternative, which separates this from the zero alternatives. The price to pay for this alternative will be the reduced charging power when the loading of the grid is high, the question is then if it can be worth it for the end-user. It depends, of course, from how much the power is reduced and for how long. If it is only 10% reduced charging power for one hour during the day and the charging station can be supplied with the desired power the rest of the day, it will be a good alternative. If the power is below 50% of the desired most of the day, and the cost to upgrade the grid to handle 100% is around 4 Mkr as in alternative two for location B and C, there is maybe not even a question. If reduced power to the charging station is an alternative, it needs to be a system for how the charging power shall be reduced for the chargers. One option is to reduce the power for all chargers immediately, so all of them have the same power, another option is to operate several chargers with full power while others do not have any power at all. A fast charging station out of function will probably destroy the business model for electric freight transport and all other vehicles that depends on the charging station to operate. Therefore will a smart charging station not be very feasible as a flexible

load. However, flexible solutions will be important in the future distribution grid. There are loads that can have a lower priority than a fast charging station, and those can be the solution for the charging station to operate in the desired operation without making any investments in the grid.

6.3 Discussion of the analysis

The technical analysis aims to see if any of the alternatives disobey with the requirements for power quality and the economical is to make a fair comparison between the different alternatives and locations. Some factors could have been taken into consideration in the analysis but are not in this thesis because of that, some of the evaluations would require calculations beyond the scope of this thesis. This is, for example, when it comes to the security of supply that will affect the technical requirements different dependent from which priority the charging station will have in the grid among others.

For the transformer stations that have two or more transformers, it may be necessary to change all of them if one needs to be replaced. This is due to the security of supply where re couplings are required if a fault occurs somewhere in the grid. This will apply if the charging station shall have a high priority in the grid so that all the transformers can handle the power demand from the charging station during an interruption in the one it is initially connected. Only the cost of one new transformer is calculated in the application chapter, but if it turns out that changing all the transformers in a transformer station is necessary, it will affect the election of the location in this model. The investment costs of a transformer is not very certain either, as the costs comes from experienced values from the grid operators. As a location with three transformers will triple the cost of an upgrade compared to a location with only one, that will make a difference in the total cost that can be seen even before doing any analysis. If the charging station has the highest priority in the grid, it will anyway require that the transformer stations nearby can supply it, resulting in an upgrade of all the transformers near the charging station. This will be decided from the level of priority of the charging station which is not discussed much in this thesis and is the reason why only one transformer is considered to be upgraded independent from how many transformers there are in the transformer station.

The technical analysis did only consider the heaviest loaded power line, not which of them it was was. The first power line from a transformer should not be loaded more than 40% in a large grid if this radial is thought to be a backup for some of the other radicals. This means that it maybe should be performed analysis for that actual cable for all the alternatives to check if a necessary upgrade of that cable could make a difference on the total cost. However, as the first cable from the transformer in one radial is relatively short, and that a 10 MW additional load probably will force an upgrade of that cable anyway to

follow this recommendation, it is considered not to be very decisive in this case.

The economic comparison between the alternatives with and without a battery is not truly fair, as the cost of the battery system is an unknown factor. This was solved by using one reference cost for the battery to compare the different location and then find the critical cost of the battery system for each location. Figure 6.2 shows how low the battery price needs to be price competitive for different locations.

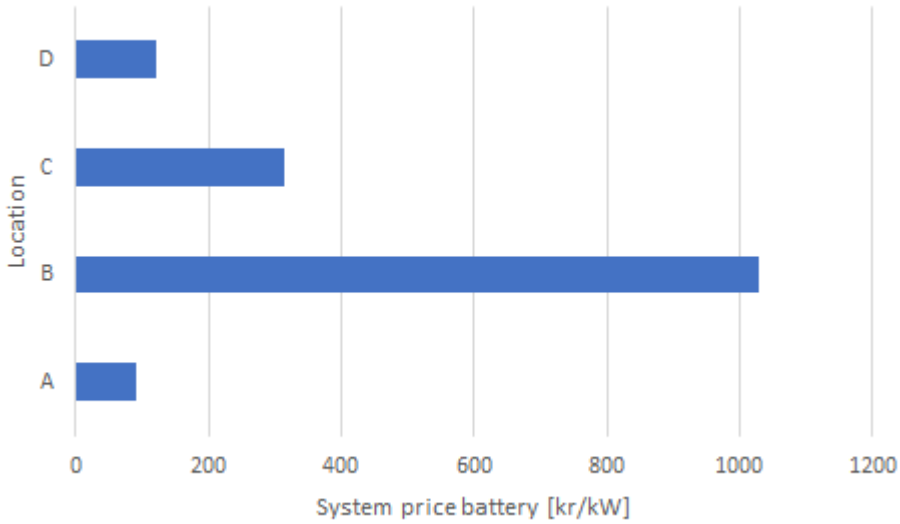

Figure 6.2: Battery price to make the alternative with battery price competitive to a reinforcement of the cables and transformers

From Figure 6.2, one can see that there is a huge difference between the four locations for what battery price a solution with a battery will be price competitive to traditional reinforcement. The location where a solution with battery will be price competitive with the highest battery price in location B. The battery price in location B is 1030 kr/kW, while it needs to be as low as 90 kr/kW in location A. Maybe are both of those prices unrealistic anyway, but it shows that the potential for installing a battery in the grid instead of upgrading the grid depends much from how the grid is constructed. This means that one cannot just say that a battery is the best option in one location and then apply the same solution anywhere. The economic analysis would have been more exact if there existed more specific costs of the battery, which could have concluded that a battery is unfeasible for this purpose or that it actually can be a good option. Such a conclusion cannot be made due to the lack of battery costs. It will be essential to have a clear strategy regarding who should own the batteries in the grid. As long as this is an unanswered question, the possible actors will probably delay considering a battery as an alternative as long a possible, which also may slow down the technology development and consequently the price on large scale

batteries in the grid. One option is that the DSO owns and operates the battery, while another possibility is that the operator of the charging station owns the battery, making the battery a part of the charging station. The method developed in this thesis will require that it exists a regulation for batteries, if not, the alternatives, including batteries, will not be very relevant. The operator of the charging station probably does not want to be responsible for a large battery and the failures that might occur in it, while the DSO cannot install a battery unless there is precise regulation on how the battery shall be operated.

It is not performed analysis of the operational costs in this thesis, but it may be that it is a significant difference between the different alternatives. The operational costs are probably the same for the four locations as they are close geographically, but the alternative with smart power management may have higher costs than an alternative with traditional reinforcement.

Chapter 7

Conclusion

A new method for planning the future distribution grid is necessary, as there is a need for both new input factors and new alternatives for grid reinvestments. First of all, there is a need for a new load profile, customized for a fast charging station. This is important as it was found that the probable load profile for a fast charging station is opposite from the load profiles that are used today. The tools for grid analysis should have a finer resolution for the load profile than only weekends and weekdays, as the traffic and by that the use of a fast charging station will have large variations within those categories. A better estimation of the charging profile for a fast charging station would have been beneficial in the planning, but since one does not know how the use of the charging station will be before it is built. An under-dimensioning probably will slow down the electrification of the transport sector. This is an uncertainty that will be there until the whole vehicle fleet eventually is electrified. There should be a standard for the requirements for the security of supply for a charging station that applies to all charging stations in Norway. This will make the charging stations more predictable for the end-users, as they have the same expectations for the chargers to be operative and remove this question from the process of the grid planner for all new charging stations. If this standard says that a charging station shall have the highest priority in the grid, it will probably make the alternative of smart power management impossible for all locations.

Even if the alternative of traditional reinforcement was the best alternative for all locations in this thesis, when only the other options supplying the desired power to the charging station is taken into account, it does not necessarily mean that this will apply for all locations forever. The total cost of the alternatives with batteries depends on the cost of the battery system, which may change in the following years. To consider an alternative with no upgrades in the grid, a smart management system to better utilize the existing grid will also be a good option, especially to postpone an upgrade of the grid some years. That solution will require that the demand is covered better than it was in some of the locations in this thesis unless the end-users are willing to change their habits when it

comes to charging. For situations where one can look at different locations, the analysis in this thesis shows that it can be significant differences in how the grid is and how much it will cost to upgrade depends from where it is. It also shows that there can be different alternatives that are most beneficial, which means that testing several alternatives in one location will be necessary to find the optimal alternative. To make all the alternatives valid, it will require that there is a precise regulation regarding the roles in the battery ownership and that a smart power management system as described in this thesis exists without much hassle in the operation of it.

Chapter 8

Further work

To find a better estimate for the charging profile of a fast charging station will be very helpful to perform more accurate grid analysis of the impacts from the charging station. This will require more information and a good model for the development of all types of vehicles and the charging technologies. To see how the transport sector is changing with the introduction of autonomous vehicles and sharing economy will be interesting, and will also have a significant impact on the use of a charging station.

The basis in this thesis is to establish a large charging station every 150 km along the main roads in Norway, but an analysis comparing the socioeconomic costs between having one large charging station compared to smaller, but more frequent charging stations will be interesting. The same yields for the question of whether the best solution is to have a common charging station for passenger cars and heavier vehicles or to separate them.

It will also be interesting to see which impact the interruption costs have on the total costs of a charging station. This will require a complete analysis of the security of supply, including reliability studies of the charging station and all components around it in the grid.

A fast charging station as a flexible load in the grid is probably not the best solution, but it would have been interesting to see if there are any locations with sufficient flexible loads to cover the demand from a fast charging station without any grid upgrades.

This thesis considers mostly what a charging station requires from the grid, not what the grid shall require from the charging station. This can be, for example, if it affects the voltage quality that will require some filter in the grid, and if this is more present in some locations than others.

Chapter 9

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**

Appendix A

Appendix A

A.1 Investment costs

$$PV(I) = (l_{cables} \cdot (I_{cables} + I_{work}) + I_{transformer}) \cdot \varepsilon_{4.5,40} \cdot \lambda_{4.5,10} + I_{battery}$$

Location A

Alternative 1

$$PV(I) = 0$$

Alternative 2

$$PV(I) = (1.929km \cdot (584198 + 433249)) + 652200) \cdot 0.059 \cdot 7.91 = 3892590kr$$

Alternative 3

$$PV(I) = ((1.929km \cdot (370990 + 433249)) + 652200) \cdot 0.059 \cdot 7.91) + 3MW \cdot 2400kr = 10903904kr$$

Alternative 4

$$PV(I) = 6MW \cdot 2400kr = 14400000kr$$

Alternative 5

$$PV(I) = (1.929km \cdot (584198 + 433249)) \cdot 0.059 \cdot 7.91 = 900427kr$$

Location B

Alternative 1

$$PV(I) = 0$$

Alternative 2

$$PV(I) = (0.76km \cdot (383001 + 433249)) + 652200) \cdot 0.059 \cdot 7.91 = 3276767kr$$

Alternative 3

$$PV(I) = (0.76km \cdot (383001 + 433249)) \cdot 0.059 \cdot 7.91) + 3MW \cdot 2400kr = 7484604kr$$

Alternative 4

$$PV(I) = 6MW \cdot 2400kr = 14400000kr$$

Alternative 5

$$PV(I) = 0$$

Location C

Alternative 1

$$PV(I) = 0$$

Alternative 2

$$PV(I) = 3.042km \cdot (584198 + 433249) \cdot 0.059 \cdot 7.91 = 1419958kr$$

Alternative 3

$$PV(I) = (3.042km \cdot (273880 + 433249)) \cdot 0.059 \cdot 7.91) + 3MW \cdot 2400kr = 8186875kr$$

Alternative 4

$$PV(I) = 6MW \cdot 2400kr = 14400000kr$$

Alternative 5

$$PV(I) = 0$$

Location D

Alternative 1

$$PV(I) = 0$$

Alternative 2

$$PV(I) = (2.761km \cdot (584198 + 433249) + 6522000) \cdot 0.059 \cdot 7.91 = 4280955kr$$

Alternative 3

$$PV(I) = (2.761km \cdot (370990 + 433249) + 6522000) \cdot 0.059 \cdot 7.91) + 3MW \cdot 2400kr = 17685369kr$$

A.2 CENS calculations

Location A

Table A.1: Share of the different customer groups for this transformer, specific costs for the reference hour

Group	Share of power	Specific interruption cost	CENS
Agriculture	1%	19 kr/kW	0.2 kr/kW
Household	34%	10.9 kr/kW	3.7 kr/kW
Industry	37%	118 kr/kW	43.6 kr/kW
Commercial	19%	196 kr/kW	37.2 kr/kW
Public sector	10%	173 kr/kW	17.3 kr/kW
Large industry	0%	51.8 kr/kW	0
Total	9547.1 kW		102.0 kr/kW
Costs			973.8 kkr

Table A.2: Share of the different customer groups for this radial, specific costs for the reference hour

Group	Share of power	Specific interruption cost	CENS
Agriculture	0%	19 kr/kW	0
Household	40%	10.9 kr/kW	4.4 kr/kW
Industry	23%	118 kr/kW	27.1 kr/kW
Commercial	29%	196 kr/kW	56.8 kr/kW
Public sector	8%	173 kr/kW	13.8 kr/kW
Large industry	0%	51.8 kr/kW	0
Total	4671 kW		102.1 kr/kW
Costs			477 kkr

Location B

Table A.3: Share of the different customer groups for this transformer, specific costs for the reference hour

Group	Share of power	Specific interruption cost	CENS
Agriculture	10 %	19 kr/kW	1.9 kr/kW
Household	20 %	10.9 kr/kW	2.2 kr/kW
Industry	45 %	118 kr/kW	53.1 kr/kW
Commercial	20 %	196 kr/kW	39.2 kr/kW
Public sector	4 %	173 kr/kW	6.9 kr/kW
Large industry	0 %	51.8 kr/kW	0
Total	18339.6 kW		103.3 kr/kW
Costs			1894.5 kkr

Table A.4: Share of the different customer groups for this radial, specific costs for the reference hour

Group	Share of power	Specific interruption cost	CENS
Agriculture	0 %	19 kr/kW	0
Household	3 %	10.9 kr/kW	0.3 kr/kW
Industry	26 %	118 kr/kW	30.7 kr/kW
Commercial	67 %	196 kr/kW	131.3 kr/kW
Public sector	4 %	173 kr/kW	6.9 kr/kW
Large industry	0 %	51.8 kr/kW	0
Total	3322.6 kW		169.3 kr/kW
Costs			562.4 kkr

Location C

Table A.5: Share of the different customer groups for this transformer, specific costs for the reference hour

Group	Share of power	Specific interruption cost	CENS
Agriculture	0	19 kr/kW	0
Household	31%	10.9 kr/kW	3.4 kr/kW
Industry	28%	118 kr/kW	33.0 kr/kW
Commercial	30%	196 kr/kW	58.8 kr/kW
Public sector	11%	173 kr/kW	19.0 kr/kW
Large industry	0 %	51.8 kr/kW	0
Total	12977.8		114.2 kr/kW
Costs			1481.8 kkr

Table A.6: Share of the different customer groups for this radial, specific costs for the reference hour

Group	Share of power	Specific interruption cost	CENS
Agriculture		19 kr/kW	0
Household	53%	10.9 kr/kW	5.8 kr/kW
Industry	7%	118 kr/kW	8.3 kr/kW
Commercial	37%	196 kr/kW	72.5 kr/kW
Public sector	3%	173 kr/kW	5.2 kr/kW
Large industry	0 %	51.8 kr/kW	0
Total	2686.2 kW		91.7 kr/kW
Costs			246.4 kkr

Location D

Table A.7: Share of the different customer groups for this transformer, specific costs for the reference hour

Group	Share of power	Specific interruption cost	CENS
Agriculture	0	19 kr/kW	
Household	20%	10.9 kr/kW	2.2 kr/kW
Industry	14%	118 kr/kW	16.5 kr/kW
Commercial	57%	196 kr/kW	111.7 kr/kW
Public sector	9%	173 kr/kW	15.6 kr/kW
Large industry	0 %	51.8 kr/kW	0
Total	32933 kW		145.9 kr/kW
Costs			4807.89 kkr

Table A.8: Share of the different customer groups for this radial, specific costs for the reference hour

Group	Share of power	Specific interruption cost	CENS
Agriculture		19 kr/kW	0
Household	3%	10.9 kr/kW	0.3 kr/kW
Industry	65%	118 kr/kW	76.7 kr/kW
Commercial	19%	196 kr/kW	37.2 kr/kW
Public sector	12%	173 kr/kW	20.8 kr/kW
Large industry	0 %	51.8 kr/kW	0
Total	5146.6 kW		135.0 kr/kW
Costs			694.8 kkr

Appendix B

Appendix B

B.1 Results from the simulations in Netbas

The following pages will include the results from the simulations in Netbas. The names of the grid components are removed. The first document for each location is a summary of the simulation in the peak load hour, where the losses in the power lines and transformers are listed separately. The next shows the minimum and maximum power in addition to the power losses for each month during a year. It also tells which hour during the year that has the maximum load. The third sheet shows the results from the economic analysis in Netbas. There is originally a long list with the name of all line section, the length of it and the type. Due to confidentiality and not attach up to 10 pages for each alternative, all line sections are removed from this attachment. What can be seen are the total length of all the power lines in the grid and the cost of losses. It also shows the economic parameters used in the analysis.

Location A
Reference

Datasett : [redacted]. Beregningsår 2019.
Tidspunkt : 2019-05-13 11:11:36. Hentet 2019-01-01.

APPENDIX B. APPENDIX B

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr	
[redacted]	61.557	:	19.027	6.981	
Sum produksjon		:	19.227	6.991	
Sum spenningsuavh. last		:	18.470	4.263	
Sum spennings-avh. last		:	0.000	0.000	
Sum tap i linjeseksj.		:	0.378	0.113	
Sum tap i T2		:	0.164	2.070	0.024
Sum tap i TF		:	0.210	0.538	0.065
Sum tap i F3		:	0.004	0.008	0.003
Sum elektriske tap		:	0.756	2.729	0.092 (Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 7.39 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 7.41 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 20.43 %
Laveste marginale tap generator : [redacted] : 13.31 %
Største belastning
Sterkest belastet linje : [redacted] : 92.11 %
Sterkest belastet T2 : [redacted] : 110.32 %
Sterkest belastet TF : [redacted] : 144.48 %
Sterkest belastet F3 : [redacted] : 38.43 %

2019	Min. effekt (MW)		Max. effekt (MW)		(MWh)	(MWh)	(%)
Mnd :	Last	Tap	Last	Tap	Last	Tap	Tap
1 :	8.920	0.2887	18.670	0.7992	10874.509	405.826	3.732
2 :	8.171	0.2599	17.008	0.6700	8951.847	312.353	3.489
3 :	9.840	0.2749	14.801	0.5300	9050.902	288.650	3.189
4 :	7.942	0.2115	11.945	0.3664	7072.863	202.171	2.858
5 :	5.974	0.1572	9.002	0.2393	5493.644	143.803	2.618
6 :	4.990	0.1375	7.530	0.1915	4438.975	115.933	2.612
7 :	4.427	0.1265	6.699	0.1684	4063.825	107.829	2.653
8 :	5.201	0.1402	7.859	0.1983	4776.118	122.883	2.573
9 :	6.888	0.1768	10.386	0.2879	6125.355	162.159	2.647
10 :	9.418	0.2543	14.195	0.4720	8653.102	259.070	2.994
11 :	10.543	0.2985	15.874	0.5767	9379.797	306.145	3.264
12 :	8.260	0.2618	17.428	0.6944	10250.472	360.451	3.516
0 :	4.427	0.1265	18.670	0.7992	89131.409	2787.274	3.127

Energiforbruk lastobjekt : 64683.513 MWh.
Totalt energiforbruk : 89131.409 MWh. Brukstid 4774 timer.
Total svingmaskin : 90166.674 MWh. Brukstid 4679 timer.
Total lokal produksjon : 1752.000 MWh. Brukstid 8760 timer.
Totale tap : 2787.274 MWh. Brukstid 3488 timer.
Tap i prosent av last : 3.127 %

Max. last måned 1 time 19 : 18.670 MW

Alternative 1

Datasett : [redacted]. Beregningsår 2019.
Tidspunkt 2019-05-13 11:12:46. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr		
[redacted]	61.557	:	26.262	10.288		
Sum produksjon		:	26.462	10.298		
Sum spenningsuavh. last		:	25.270	5.967		
Sum spennings-avh. last		:	0.000	0.000		
Sum tap i linjeseksj.		:	0.715	0.329		
Sum tap i T2		:	0.262	3.450	0.024	
Sum tap i TF		:	0.210	0.544	0.065	
Sum tap i F3		:	0.004	0.008	0.003	
Sum elektriske tap		:	1.191	4.331	0.091	(Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 7.39 %
Spenningsfall høyspenning ref. trafo : [redacted] : 0.00 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 7.41 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 20.43 %
Laveste marginale tap generator : [redacted] : 13.31 %
Største belastning
Sterkest belastet linje : [redacted] : 236.99 %
Sterkest belastet T2 : [redacted] : 192.12 %
Sterkest belastet TF : [redacted] : 144.48 %
Sterkest belastet F3 : [redacted] : 38.43 %

2019 Mnd :	Min. effekt (MW) Last	Tap	Max. effekt (MW) Last	Tap	(MWh) Last	(MWh) Tap	(%) Tap
1 :	9.328	0.2938	25.270	1.1976	13684.609	550.654	4.024
2 :	8.639	0.2654	24.614	1.1412	11866.864	464.754	3.916
3 :	10.160	0.2807	22.633	1.0149	12323.222	451.405	3.663
4 :	8.238	0.2159	19.408	0.7662	10045.603	330.383	3.289
5 :	6.246	0.1606	16.407	0.5954	8534.819	261.062	3.059
6 :	5.291	0.1409	16.257	0.6450	7881.095	257.880	3.272
7 :	4.756	0.1299	16.642	0.7373	8225.225	296.305	3.602
8 :	5.527	0.1441	17.488	0.7571	8778.241	306.636	3.493
9 :	7.189	0.1814	18.582	0.7443	9430.830	309.262	3.279
10 :	9.722	0.2599	21.748	0.9332	11857.380	416.568	3.513
11 :	10.823	0.3041	22.702	1.0007	12167.547	442.099	3.633
12 :	8.656	0.2664	23.860	1.0816	12907.038	491.151	3.805
0 :	4.756	0.1299	25.270	1.1976	127702.472	4578.161	3.585

Energiforbruk lastobjekt : 64708.513 MWh.
Totalt energiforbruk : 127702.472 MWh. Brukstid 5053 timer.
Total svingmaskin : 130528.627 MWh. Brukstid 4970 timer.
Total lokal produksjon : 1752.000 MWh. Brukstid 8760 timer.
Totale tap : 4578.161 MWh. Brukstid 3823 timer.
Tap i prosent av last : 3.585 %

Max. last måned 1 time 17 : 25.270 MW

APPENDIX B. APPENDIX B

Alternative 2

Datasett : [redacted]. Beregningsår 2019.
Tidspunkt 2019-05-13 11:05:03. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr		
[redacted]	61.557	:	25.878	8.861		
Sum produksjon		:	26.078	8.871		
Sum spenningsuavh. last		:	25.270	5.967		
Sum spennings-avh. last		:	0.000	0.000		
Sum tap i linjeseksj.		:	0.435	0.390		
Sum tap i T2		:	0.158	1.958	0.023	
Sum tap i TF		:	0.211	0.547	0.065	
Sum tap i F3		:	0.004	0.008	0.003	
Sum elektriske tap		:	0.807	2.904	0.091	(Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 7.28 %
Spenningsfall høyspenning ref. trafo : [redacted] : 0.00 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 7.40 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 19.24 %
Laveste marginale tap generator : [redacted] : 12.29 %
Største belastning
Sterkest belastet linje : [redacted] : 97.17 %
Sterkest belastet T2 : [redacted] : 92.58 %
Sterkest belastet TF : [redacted] : 144.31 %
Sterkest belastet F3 : [redacted] : 38.38 %

2019	Min. effekt (MW)		Max. effekt (MW)		(MWh)	(MWh)	(%)
Mnd :	Last	Tap	Last	Tap	Last	Tap	Tap
1 :	9.328	0.2748	25.270	0.8262	13684.609	409.213	2.990
2 :	8.639	0.2449	24.614	0.7320	11866.864	328.998	2.772
3 :	10.160	0.2557	22.633	0.6027	12323.222	310.584	2.520
4 :	8.238	0.1974	19.408	0.4495	10045.603	225.005	2.240
5 :	6.246	0.1493	16.407	0.3237	8534.819	169.305	1.984
6 :	5.291	0.1309	16.257	0.3102	7881.095	151.312	1.920
7 :	4.756	0.1221	16.642	0.3217	8225.225	157.171	1.911
8 :	5.527	0.1332	17.488	0.3446	8778.241	169.351	1.929
9 :	7.189	0.1664	18.582	0.3923	9430.830	193.138	2.048
10 :	9.722	0.2336	21.748	0.5543	11857.380	282.518	2.383
11 :	10.823	0.2754	22.702	0.6298	12167.547	316.616	2.602
12 :	8.656	0.2461	23.860	0.7223	12907.038	364.547	2.824
0 :	4.756	0.1221	25.270	0.8262	127702.472	3077.760	2.410

Energiforbruk lastobjekt : 64708.513 MWh.
Totalt energiforbruk : 127702.472 MWh. Brukstid 5053 timer.
Total svingmaskin : 129028.224 MWh. Brukstid 4986 timer.
Total lokal produksjon : 1752.000 MWh. Brukstid 8760 timer.
Totale tap : 3077.760 MWh. Brukstid 3725 timer.

Tap i prosent av last : 2.410 %

Max. last måned 1 time 17 : 25.270 MW

APPENDIX B. APPENDIX B

Alternative 3

Datasett : [redacted]. Beregningsår 2019.
Tidspunkt 2019-05-13 11:08:30. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr		
[redacted]	61.557	:	23.822	8.011		
Sum produksjon		:	24.022	8.021		
Sum spenningsuavh. last		:	23.230	5.456		
Sum spennings-avh. last		:	0.000	0.000		
Sum tap i linjeseksj.		:	0.436	0.298		
Sum tap i T2		:	0.141	1.713	0.023	
Sum tap i TF		:	0.211	0.546	0.065	
Sum tap i F3		:	0.004	0.008	0.003	
Sum elektriske tap		:	0.792	2.565	0.091	(Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 7.28 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 7.40 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 19.24 %
Laveste marginale tap generator : [redacted] : 12.29 %
Største belastning
Sterkest belastet linje : [redacted] : 86.54 %
Sterkest belastet T2 : [redacted] : 80.69 %
Sterkest belastet TF : [redacted] : 144.31 %
Sterkest belastet F3 : [redacted] : 38.38 %

2019 Mnd :	Min. effekt (MW) Last	Tap	Max. effekt (MW) Last	Tap	(MWh) Last	(MWh) Tap	(%) Tap
1 :	9.206	0.2755	23.230	0.8143	12841.579	404.765	3.152
2 :	8.498	0.2454	22.274	0.7117	10992.359	322.866	2.937
3 :	10.064	0.2573	20.233	0.5785	11341.526	303.429	2.675
4 :	8.155	0.1984	17.128	0.4278	9153.781	218.671	2.389
5 :	6.179	0.1499	14.157	0.3027	7622.467	162.836	2.136
6 :	5.211	0.1313	13.617	0.2811	6848.459	142.566	2.082
7 :	4.666	0.1225	13.642	0.2841	6976.805	144.957	2.078
8 :	5.440	0.1337	14.578	0.3089	7577.604	157.971	2.085
9 :	7.114	0.1672	16.092	0.3663	8439.188	185.262	2.195
10 :	9.633	0.2352	19.438	0.5322	10896.097	275.878	2.532
11 :	10.739	0.2773	20.602	0.6122	11331.222	311.825	2.752
12 :	8.537	0.2466	21.880	0.7110	12110.068	360.567	2.977
0 :	4.666	0.1225	23.230	0.8143	116131.153	2991.593	2.576

Energiforbruk lastobjekt : 64708.513 MWh.
Totalt energiforbruk : 116131.153 MWh. Brukstid 4999 timer.
Total svingmaskin : 117370.737 MWh. Brukstid 4927 timer.
Total lokal produksjon : 1752.000 MWh. Brukstid 8760 timer.

Totale tap : 2991.593 MWh. Brukstid 3674 timer.
Tap i prosent av last : 2.576 %

Max. last måned 1 time 17 : 23.230 MW

Alternative 4
Datasett : [redacted]. Beregningsår 2019.
Tidspunkt 2019-05-13 11:14:13. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr		
BIRI66T1	61.557	:	21.876	8.204		
Sum produksjon		:	22.076	8.214		
Sum spenningsuavh. last		:	21.190	4.944		
Sum spennings-avh. last		:	0.000	0.000		
Sum tap i linjeseksj.		:	0.473	0.177		
Sum tap i T2		:	0.197	2.540	0.024	
Sum tap i TF		:	0.211	0.545	0.065	
Sum tap i F3		:	0.004	0.008	0.003	
Sum elektriske tap		:	0.885	3.270	0.091	(Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 7.39 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 7.41 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 20.43 %
Laveste marginale tap generator : [redacted] : 13.31 %
Største belastning
Sterkest belastet linje : [redacted] : 150.29 %
Sterkest belastet T2 : [redacted] : 140.29 %
Sterkest belastet TF : [redacted] : 144.48 %
Sterkest belastet F3 : [redacted] : 38.43 %

2019	Min. effekt (MW)		Max. effekt (MW)		(MWh)	(MWh)	(%)
Mnd :	Last	Tap	Last	Tap	Last	Tap	Tap
1 :	9.083	0.2906	21.190	0.9091	11998.549	446.895	3.725
2 :	8.358	0.2619	19.934	0.7854	10117.854	353.466	3.493
3 :	9.968	0.2771	17.833	0.6397	10359.830	331.823	3.203
4 :	8.064	0.2132	14.848	0.4617	8261.959	235.451	2.850
5 :	6.094	0.1585	11.907	0.3221	6710.114	172.608	2.572
6 :	5.131	0.1389	10.977	0.2904	5815.823	148.162	2.548
7 :	4.576	0.1280	10.642	0.2874	5728.385	148.505	2.592
8 :	5.353	0.1418	11.668	0.3191	6376.968	164.165	2.574
9 :	7.020	0.1785	13.602	0.3949	7447.545	198.704	2.668
10 :	9.541	0.2564	17.128	0.5798	9934.813	301.238	3.032
11 :	10.655	0.3007	18.502	0.6872	10494.897	343.803	3.276
12 :	8.418	0.2635	19.900	0.7898	11313.098	397.361	3.512
0 :	4.576	0.1280	21.190	0.9091	104559.835	3242.181	3.101

Energiforbruk lastobjekt : 64708.513 MWh.
Totalt energiforbruk : 104559.835 MWh. Brukstid 4934 timer.
Total svingmaskin : 106050.009 MWh. Brukstid 4848 timer.

Total lokal produksjon : 1752.000 MWh. Brukstid 8760 timer.
Totale tap : 3242.181 MWh. Brukstid 3566 timer.
Tap i prosent av last : 3.101 %

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Max. last måned 1 time 17 : 21.190 MW

Alternative 5

Datasett : [redacted]. Beregningsår 2019.
Tidspunkt 2019-05-14 11:15:31. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr		
[redacted]	61.557	:	20.012	7.395		
Sum produksjon		:	20.212	7.405		
Sum spenningsuavh. last		:	19.470	4.513		
Sum spennings-avh. last		:	0.000	0.000		
Sum tap i linjeseksj.		:	0.353	0.129		
Sum tap i T2		:	0.175	2.217	0.024	
Sum tap i TF		:	0.210	0.538	0.065	
Sum tap i F3		:	0.004	0.008	0.003	
Sum elektriske tap		:	0.741	2.892	0.092	(Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 7.39 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 7.41 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 20.43 %
Laveste marginale tap generator : [redacted] : 13.31 %
Største belastning
Sterkest belastet linje : [redacted] : 80.88 %
Sterkest belastet T2 : [redacted] : 118.58 %
Sterkest belastet TF : [redacted] : 144.48 %
Sterkest belastet F3 : [redacted] : 38.43 %

APPENDIX B. APPENDIX B

Location A
Reference

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		98.539		0.	0.	5945354.		5945354.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 1

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		98.539		0.	0.	15977373.		15977373.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 2

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		98.539		0.	0.	8162003.		8162003.

APPENDIX B. APPENDIX B

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 3

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		98.539		0.	0.	8211459.		8211459.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 4

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		98.539		0.	0.	8886904.		8886904.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Location B

Reference

Dataset: [redacted] Beregningsår 2019.
Tidspunkt 2019-05-13 11:17:14. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV	MW	MVAr	
[redacted]	64.079	19.477	2.614	
Sum produksjon		19.477	2.614	
Sum spenningsuavh. last		19.128	4.679	
Sum spennings-avh. last		0.000	-3.431	
Sum tap i linjeseksj.		0.083	-1.106	
Sum tap i T2		0.075	1.871	0.011
Sum tap i TF		0.187	0.598	0.054
Sum tap i F3		0.004	0.003	0.003
Sum elektriske tap		0.349	1.366	0.068 (Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 2.91 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 2.17 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 8.12 %
Største belastning
Sterkest belastet linje : [redacted] : 48.95 %
Sterkest belastet T2 : [redacted] : 101.20 %
Sterkest belastet TF : [redacted] : 141.97 %
Sterkest belastet F3 : [redacted] : 32.46 %

2019 Mnd :	Min. effekt (MW) Last	Min. effekt (MW) Tap	Max. effekt (MW) Last	Max. effekt (MW) Tap	(MWh) Last	(MWh) Tap	(%) Tap
1 :	5.445	0.1135	19.128	0.3488	10013.602	170.483	1.703
2 :	4.945	0.1071	17.275	0.2959	8168.670	134.848	1.651
3 :	9.383	0.1401	14.339	0.2301	8590.330	132.628	1.544
4 :	7.528	0.1162	11.503	0.1745	6670.409	101.056	1.515
5 :	6.074	0.1000	9.291	0.1351	5559.129	85.074	1.530
6 :	5.347	0.0936	8.185	0.1196	4734.556	74.996	1.584
7 :	5.172	0.0917	7.927	0.1151	4731.289	75.198	1.589
8 :	5.834	0.0967	8.937	0.1274	5337.455	81.158	1.521
9 :	7.201	0.1099	11.020	0.1597	6377.604	93.718	1.469
10 :	9.674	0.1406	14.801	0.2323	8853.845	133.015	1.502
11 :	10.445	0.1542	15.971	0.2645	9252.537	143.961	1.556
12 :	5.106	0.1080	18.083	0.3156	9637.794	158.993	1.650
0 :	4.945	0.0917	19.128	0.3488	87927.219	1385.128	1.575

Energiforbruk lastobjekt : 68579.475 MWh.
Totalt energiforbruk : 87927.219 MWh. Brukstid 4597 timer.
Total svingmaskin : 89312.333 MWh. Brukstid 4585 timer.
Totale tap : 1385.128 MWh. Brukstid 3971 timer.
Tap i prosent av last : 1.575 %

Max. last måned 1 time 17 : 19.128 MW

Alternative 1

Datasett : [redacted]. Beregningsår 2019.
Tidspunkt 2019-05-13 11:19:51. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr	
[redacted]	64.079	:	26.348	5.816	
Sum produksjon		:	26.348	5.816	
Sum spenningsuavh. last		:	25.928	6.383	
Sum spennings-avh. last		:	0.000	-3.467	
Sum tap i linjeseksj.		:	0.101	-1.100	
Sum tap i T2		:	0.129	3.405	0.011
Sum tap i TF		:	0.186	0.592	0.055
Sum tap i F3		:	0.004	0.003	0.003
Sum elektriske tap		:	0.420	2.900	0.069 (Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 2.91 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 2.15 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 8.32 %
Største belastning
Sterkest belastet linje : [redacted] : 68.15 %
Sterkest belastet T2 : [redacted] : 138.96 %
Sterkest belastet TF : [redacted] : 141.44 %
Sterkest belastet F3 : [redacted] : 32.30 %

2019	Min. effekt (MW)		Max. effekt (MW)		(MWh)	(MWh)	(%)
Mnd :	Last	Tap	Last	Tap	Last	Tap	Tap
1 :	5.853	0.1143	25.928	0.4198	12819.214	194.992	1.521
2 :	5.413	0.1079	25.075	0.3749	11079.006	158.826	1.434
3 :	9.649	0.1413	22.287	0.3048	11862.650	157.271	1.326
4 :	7.777	0.1171	19.061	0.2309	9643.149	119.574	1.240
5 :	6.313	0.1007	16.762	0.1838	8600.304	101.430	1.179
6 :	5.622	0.0943	16.962	0.1775	8176.676	93.430	1.143
7 :	5.481	0.0924	17.910	0.1850	8892.689	98.745	1.110
8 :	6.136	0.0975	18.615	0.1985	9339.578	104.996	1.124
9 :	7.467	0.1108	19.288	0.2231	9683.079	114.580	1.183
10 :	9.928	0.1419	22.455	0.3057	12058.123	157.447	1.306
11 :	10.682	0.1554	22.918	0.3254	12040.287	166.104	1.380
12 :	5.502	0.1087	24.683	0.3806	12290.598	181.008	1.473
0 :	5.413	0.0924	25.928	0.4198	126485.352	1648.402	1.303

Energiforbruk lastobjekt : 68604.475 MWh.
Totalt energiforbruk : 126485.352 MWh. Brukstid 4878 timer.
Total svingmaskin : 128133.743 MWh. Brukstid 4863 timer.
Totale tap : 1648.402 MWh. Brukstid 3927 timer.
Tap i prosent av last : 1.303 %

Max. last måned 1 time 17 : 25.928 MW

Alternative 3

Datasett : [redacted]. Beregningsår 2019.
Tidspunkt 2019-05-13 11:22:51. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr		
[redacted]	64.079	:	26.296	4.514		
Sum produksjon		:	26.296	4.514		
Sum spenningsuavh. last		:	25.928	6.383		
Sum spennings-avh. last		:	0.000	-3.540		
Sum tap i linjeseksj.		:	0.092	-1.130		
Sum tap i T2		:	0.088	2.219	0.011	
Sum tap i TF		:	0.184	0.579	0.056	
Sum tap i F3		:	0.004	0.003	0.003	
Sum elektriske tap		:	0.368	1.672	0.070	(Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 2.91 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 2.10 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 7.75 %
Største belastning
Sterkest belastet linje : [redacted] : 53.82 %
Sterkest belastet T2 : [redacted] : 91.60 %
Sterkest belastet TF : [redacted] : 139.78 %
Sterkest belastet F3 : [redacted] : 31.96 %

2019	Min. effekt (MW)		Max. effekt (MW)		(MWh)	(MWh)	(%)
Mnd :	Last	Tap	Last	Tap	Last	Tap	Tap
1 :	5.853	0.1113	25.928	0.3772	12819.214	177.893	1.388
2 :	5.413	0.1051	25.075	0.3338	11079.006	144.128	1.301
3 :	9.649	0.1353	22.287	0.2652	11862.650	142.343	1.200
4 :	7.777	0.1127	19.061	0.2025	9643.149	109.179	1.132
5 :	6.313	0.0972	16.762	0.1615	8600.304	92.881	1.080
6 :	5.622	0.0912	16.962	0.1532	8176.676	84.713	1.036
7 :	5.481	0.0893	17.910	0.1568	8892.689	88.300	0.993
8 :	6.136	0.0942	18.615	0.1687	9339.578	94.035	1.007
9 :	7.467	0.1067	19.288	0.1932	9683.079	103.677	1.071
10 :	9.928	0.1355	22.455	0.2658	12058.123	142.322	1.180
11 :	10.682	0.1482	22.918	0.2922	12040.287	150.989	1.254
12 :	5.502	0.1058	24.683	0.3424	12290.598	165.325	1.345
0 :	5.413	0.0893	25.928	0.3772	126485.352	1495.785	1.183

Energiforbruk lastobjekt : 68604.475 MWh.
Totalt energiforbruk : 126485.352 MWh. Brukstid 4878 timer.
Total svingmaskin : 127981.125 MWh. Brukstid 4865 timer.
Totale tap : 1495.785 MWh. Brukstid 3965 timer.
Tap i prosent av last : 1.183 %

Max. last måned 1 time 17 : 25.928 MW

Alternative 3

Datasett : [redacted]. Beregningsår 2019.
Tidspunkt 2019-05-13 11:26:17. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr		
[redacted]	64.079	:	24.275	4.698		
Sum produksjon		:	24.275	4.698		
Sum spenningsuavh. last		:	23.888	5.872		
Sum spennings-avh. last		:	0.000	-3.498		
Sum tap i linjeseksj.		:	0.088	-1.124		
Sum tap i T2		:	0.110	2.859	0.011	
Sum tap i TF		:	0.185	0.586	0.056	
Sum tap i F3		:	0.004	0.003	0.003	
Sum elektriske tap		:	0.387	2.324	0.070	(Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 2.91 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 2.12 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 8.14 %
Største belastning
Sterkest belastet linje : [redacted] : 49.87 %
Sterkest belastet T2 : [redacted] : 127.33 %
Sterkest belastet TF : [redacted] : 140.62 %
Sterkest belastet F3 : [redacted] : 32.15 %

2019	Min. effekt (MW)		Max. effekt (MW)		(MWh)	(MWh)	(%)
Mnd :	Last	Tap	Last	Tap	Last	Tap	Tap
1 :	5.731	0.1140	23.888	0.3867	11977.530	184.868	1.543
2 :	5.272	0.1076	22.735	0.3384	10205.905	148.713	1.457
3 :	9.577	0.1407	19.887	0.2709	10880.954	146.173	1.343
4 :	7.709	0.1167	16.781	0.2042	8751.327	111.219	1.271
5 :	6.246	0.1004	14.512	0.1608	7687.951	93.859	1.221
6 :	5.543	0.0940	14.322	0.1493	7144.040	84.497	1.183
7 :	5.391	0.0921	14.910	0.1503	7644.269	87.072	1.139
8 :	6.049	0.0972	15.705	0.1638	8138.941	93.493	1.149
9 :	7.392	0.1104	16.798	0.1930	8691.436	105.004	1.208
10 :	9.859	0.1412	20.145	0.2728	11096.840	146.600	1.321
11 :	10.619	0.1548	20.818	0.3029	11203.962	156.573	1.397
12 :	5.384	0.1084	22.703	0.3504	11494.757	171.801	1.495
0 :	5.272	0.0921	23.888	0.3867	114917.912	1529.873	1.331

Energiforbruk lastobjekt : 68604.475 MWh.
Totalt energiforbruk : 114917.912 MWh. Brukstid 4811 timer.
Total svingmaskin : 116447.774 MWh. Brukstid 4797 timer.
Totale tap : 1529.873 MWh. Brukstid 3956 timer.
Tap i prosent av last : 1.331 %

Max. last måned 1 time 17 : 23.888 MW

Alternative 4

Datasett : [redacted]. Beregningsår 2019.

Tidspunkt 2019-05-13 11:29:04. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

APPENDIX B. APPENDIX B

Oppsummering :

	kV		MW	MVAr	
[redacted]	64.079	:	22.216	3.649	
Sum produksjon		:	22.216	3.649	
Sum spenningsuavh. last		:	21.848	5.360	
Sum spennings-avh. last		:	0.000	-3.528	
Sum tap i linjeseksj.		:	0.086	-1.138	
Sum tap i T2		:	0.093	2.370	0.011
Sum tap i TF		:	0.185	0.581	0.056
Sum tap i F3		:	0.004	0.003	0.003
Sum elektriske tap		:	0.367	1.816	0.070 (Tomgangstap)

Største spenningsfall

Spenningsfall referert basisspenning : [redacted] : 2.91 %

Spenningsfall mellomspgenning ref. trafo : [redacted] : 2.10 %

Marginale tap

Høyeste marginale tap lastpunkt : [redacted] : 7.97 %

Største belastning

Sterkest belastet linje : [redacted] : 48.25 %

Sterkest belastet T2 : [redacted] : 115.94 %

Sterkest belastet TF : [redacted] : 139.97 %

Sterkest belastet F3 : [redacted] : 32.01 %

2019	Min. effekt (MW)		Max. effekt (MW)		(MWh)	(MWh)	(%)
Mnd :	Last	Tap	Last	Tap	Last	Tap	Tap
1 :	5.608	0.1138	21.848	0.3672	11135.847	178.982	1.607
2 :	5.132	0.1074	20.395	0.3249	9332.804	142.732	1.529
3 :	9.505	0.1406	17.487	0.2520	9899.258	140.074	1.415
4 :	7.640	0.1165	14.501	0.1897	7859.505	106.848	1.359
5 :	6.178	0.1003	12.262	0.1491	6775.599	89.900	1.327
6 :	5.464	0.0939	11.682	0.1352	6111.404	80.043	1.310
7 :	5.301	0.0920	11.910	0.1334	6395.849	81.393	1.273
8 :	5.962	0.0971	12.795	0.1468	6938.304	87.737	1.265
9 :	7.317	0.1103	14.308	0.1773	7699.794	100.035	1.299
10 :	9.790	0.1411	17.835	0.2544	10135.557	140.601	1.387
11 :	10.556	0.1547	18.718	0.2854	10367.637	151.088	1.457
12 :	5.265	0.1082	20.723	0.3410	10698.916	166.560	1.557
0 :	5.132	0.0920	21.848	0.3672	103350.472	1465.993	1.418

Energiforbruk lastobjekt : 68604.475 MWh.

Totalt energiforbruk : 103350.472 MWh. Brukstid 4730 timer.

Total svingmaskin : 104816.453 MWh. Brukstid 4718 timer.

Totale tap : 1465.993 MWh. Brukstid 3992 timer.

Tap i prosent av last : 1.418 %

Max. last måned 1 time 17 : 21.848 MW

Alternative 5

Datasett : [redacted]. Beregningsår 2019.
Tidspunkt : 2019-05-14 11:19:46. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr	
[redacted]	64.079	:	22.903	3.994	
Sum produksjon		:	22.903	3.994	
Sum spenningsuavh. last		:	22.528	5.531	
Sum spennings-avh. last		:	0.000	-3.518	
Sum tap i linjeseksj.		:	0.088	-1.132	
Sum tap i T2		:	0.098	2.528	0.011
Sum tap i TF		:	0.185	0.583	0.056
Sum tap i F3		:	0.004	0.003	0.003
Sum elektriske tap		:	0.375	1.981	0.070 (Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 2.91 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 2.11 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 8.03 %
Største belastning
Sterkest belastet linje : [redacted] : 48.32 %
Sterkest belastet T2 : [redacted] : 119.73 %
Sterkest belastet TF : [redacted] : 140.21 %
Sterkest belastet F3 : [redacted] : 32.06 %

APPENDIX B. APPENDIX B

Location B
Reference

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		66.786		0.	0.	1354458.		1354458.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 1

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		66.786		0.	0.	1838407.		1838407.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 2

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		66.786		0.	0.	1616760.		1616760.

APPENDIX B. APPENDIX B

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 3

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		66.786		0.	0.	1511108.		1511108.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 4

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		66.786		0.	0.	1449874.		1449874.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Location C
Reference
Datasett : [redacted]. Beregningsår 2019.
Tidspunkt 2019-05-13 12:40:07. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr		
[redacted]	61.801	:	12.409	0.266		
Sum produksjon		:	12.409	0.266		
Sum spenningsuavh. last		:	12.186	2.933		
Sum spennings-avh. last		:	0.000	-3.496		
Sum tap i linjeseksj.		:	0.038	-0.225		
Sum tap i T2		:	0.041	0.737	0.014	
Sum tap i TF		:	0.141	0.311	0.047	
Sum tap i F3		:	0.002	0.005	0.001	
Sum elektriske tap		:	0.223	0.829	0.062	(Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 47.42 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 0.73 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 4.34 %
Største belastning
Sterkest belastet linje : [redacted] : 37.19 %
Sterkest belastet T2 : [redacted] : 66.27 %
Sterkest belastet TF : [redacted] : 114.84 %
Sterkest belastet F3 : [redacted] : 40.16 %

2019 Mnd :	Min. effekt (MW) Last	Tap	Max. effekt (MW) Last	Tap	(MWh) Last	(MWh) Tap	(%) Tap
1 :	3.824	0.0914	12.186	0.2228	6496.260	115.949	1.785
2 :	3.480	0.0876	11.018	0.1934	5307.225	93.767	1.767
3 :	6.053	0.1050	9.227	0.1564	5545.933	94.028	1.695
4 :	4.861	0.0917	7.409	0.1241	4310.780	75.716	1.756
5 :	3.880	0.0825	5.922	0.1022	3553.687	67.406	1.897
6 :	3.389	0.0789	5.178	0.0936	3003.293	61.111	2.035
7 :	3.240	0.0779	4.957	0.0912	2965.094	61.901	2.088
8 :	3.675	0.0807	5.618	0.0981	3363.584	65.252	1.940
9 :	4.581	0.0881	6.996	0.1160	4059.702	71.625	1.764
10 :	6.171	0.1053	9.420	0.1577	5650.478	94.292	1.669
11 :	6.699	0.1129	10.219	0.1758	5937.645	99.907	1.683
12 :	3.576	0.0880	11.501	0.2045	6231.493	109.336	1.755
0 :	3.240	0.0779	12.186	0.2228	56425.175	1010.290	1.790

Energiforbruk lastobjekt : 41368.332 MWh.
Totalt energiforbruk : 56425.175 MWh. Brukstid 4630 timer.
Total svingmaskin : 57435.453 MWh. Brukstid 4629 timer.
Totale tap : 1010.290 MWh. Brukstid 4535 timer.
Tap i prosent av last : 1.790 %

Max. last måned 1 time 17 : 12.186 MW

Alternative 1
Datasett : [redacted]. Beregningsår 2019.
Tidspunkt 2019-05-13 12:42:35. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr		
[redacted]	61.801	:	19.561	3.210		
Sum produksjon		:	19.561	3.210		
Sum spenningsuavh. last		:	18.986	4.637		
Sum spennings-avh. last		:	0.000	-3.538		
Sum tap i linjeseksj.		:	0.352	-0.018		
Sum tap i T2		:	0.080	1.813	0.015	
Sum tap i TF		:	0.141	0.310	0.047	
Sum tap i F3		:	0.002	0.005	0.001	
Sum elektriske tap		:	0.576	2.111	0.063	(Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 48.76 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 4.19 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 11.07 %
Største belastning
Sterkest belastet linje : [redacted] : 201.09 %
Sterkest belastet T2 : [redacted] : 105.85 %
Sterkest belastet TF : [redacted] : 114.61 %
Sterkest belastet F3 : [redacted] : 39.92 %

2019 Mnd :	Min. effekt (MW) Last	Min. effekt (MW) Tap	Max. effekt (MW) Last	Max. effekt (MW) Tap	(MWh) Last	(MWh) Tap	(%) Tap
1 :	4.232	0.0941	18.986	0.5755	9301.872	230.157	2.474
2 :	3.948	0.0906	18.818	0.6286	8217.561	220.958	2.689
3 :	6.315	0.1076	17.183	0.5853	8818.253	233.928	2.653
4 :	5.107	0.0935	14.973	0.4902	7283.520	191.273	2.626
5 :	4.117	0.0839	13.397	0.4542	6594.862	179.536	2.722
6 :	3.663	0.0803	13.958	0.5452	6445.413	203.390	3.156
7 :	3.547	0.0794	14.942	0.6715	7126.494	253.769	3.561
8 :	3.975	0.0824	15.299	0.6547	7365.707	247.769	3.364
9 :	4.844	0.0900	15.268	0.5432	7365.177	208.107	2.826
10 :	6.421	0.1077	17.081	0.5589	8854.756	227.820	2.573
11 :	6.931	0.1153	17.173	0.5213	8725.395	210.452	2.412
12 :	3.972	0.0905	18.101	0.5309	8884.297	212.257	2.389
0 :	3.547	0.0794	18.986	0.6715	94983.308	2619.416	2.758

Energiforbruk lastobjekt : 41393.332 MWh.
Totalt energiforbruk : 94983.308 MWh. Brukstid 5003 timer.
Total svingmaskin : 97602.713 MWh. Brukstid 4990 timer.
Totale tap : 2619.416 MWh. Brukstid 3901 timer.
Tap i prosent av last : 2.758 %

Max. last måned 1 time 17 : 18.986 MW

Alternative 2
Datasett : [redacted]. Beregningsår 2019.
Tidspunkt 2019-05-13 12:45:20. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering

	kV		MW	MVAr		
[redacted]	61.801	:	19.328	3.224		
Sum produksjon		:	19.328	3.224		
Sum spenningsuavh. last		:	18.986	4.637		
Sum spennings-avh. last		:	0.000	-3.537		
Sum tap i linjeseksj.		:	0.120	0.039		
Sum tap i T2		:	0.078	1.772	0.015	
Sum tap i TF		:	0.141	0.309	0.048	
Sum tap i F3		:	0.002	0.005	0.001	
Sum elektriske tap		:	0.342	2.124	0.063	(Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 47.68 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 1.88 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 5.03 %
Største belastning
Sterkest belastet linje : [redacted] : 79.50 %
Sterkest belastet T2 : [redacted] : 104.63 %
Sterkest belastet TF : [redacted] : 114.35 %
Sterkest belastet F3 : [redacted] : 39.93 %

2019	Min. effekt (MW)		Max. effekt (MW)		(MWh)	(MWh)	(%)
Mnd :	Last	Tap	Last	Tap	Last	Tap	Tap
1 :	4.232	0.0917	18.986	0.3417	9301.872	154.165	1.657
2 :	3.948	0.0882	18.818	0.3382	8217.561	135.992	1.655
3 :	6.315	0.1049	17.183	0.2965	8818.253	140.070	1.588
4 :	5.107	0.0917	14.973	0.2430	7283.520	113.340	1.556
5 :	4.117	0.0826	13.397	0.2145	6594.862	103.319	1.567
6 :	3.663	0.0791	13.958	0.2352	6445.413	105.672	1.639
7 :	3.547	0.0782	14.942	0.2701	7126.494	121.356	1.703
8 :	3.975	0.0810	15.299	0.2715	7365.707	122.431	1.662
9 :	4.844	0.0882	15.268	0.2532	7365.177	115.590	1.569
10 :	6.421	0.1051	17.081	0.2896	8854.756	138.442	1.563
11 :	6.931	0.1123	17.173	0.2905	8725.395	136.747	1.567
12 :	3.972	0.0884	18.101	0.3145	8884.297	143.768	1.618
0 :	3.547	0.0782	18.986	0.3417	94983.308	1530.890	1.612

Energiforbruk lastobjekt : 41393.332 MWh.
Totalt energiforbruk : 94983.308 MWh. Brukstid 5003 timer.
Total svingmaskin : 96514.189 MWh. Brukstid 4994 timer.
Totale tap : 1530.890 MWh. Brukstid 4480 timer.
Tap i prosent av last : 1.612 %

Max. last måned 1 time 17 : 18.986 MW

Alternative 3
Datasett : [redacted] Beregningsår 2019.
Tidspunkt 2019-05-13 12:48:14. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr	
[redacted]	61.801	:	17.316	2.235	
Sum produksjon		:	17.316	2.235	
Sum spenningsuavh. last		:	16.946	4.126	
Sum spennings-avh. last		:	0.000	-3.567	
Sum tap i linjeseksj.		:	0.161	-0.043	
Sum tap i T2		:	0.065	1.406	0.015
Sum tap i TF		:	0.141	0.307	0.048
Sum tap i F3		:	0.002	0.005	0.001
Sum elektriske tap		:	0.370	1.675	0.064 (Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 47.85 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 2.67 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 6.98 %
Største belastning
Sterkest belastet linje : [redacted] : 84.43 %
Sterkest belastet T2 : [redacted] : 93.23 %
Sterkest belastet TF : [redacted] : 114.02 %
Sterkest belastet F3 : [redacted] : 39.76 %

2019 Mnd :	Min. effekt (MW) Last	Min. effekt (MW) Tap	Max. effekt (MW) Last	Max. effekt (MW) Tap	(MWh) Last	(MWh) Tap	(%) Tap
1 :	4.110	0.0928	16.946	0.3698	8460.188	164.405	1.943
2 :	3.807	0.0891	16.478	0.3698	7344.461	146.201	1.991
3 :	6.243	0.1064	14.783	0.3262	7836.557	151.698	1.936
4 :	5.039	0.0926	12.693	0.2733	6391.698	122.501	1.917
5 :	4.050	0.0832	11.147	0.2369	5682.509	110.950	1.952
6 :	3.584	0.0796	11.318	0.2677	5412.777	114.998	2.125
7 :	3.457	0.0786	11.942	0.3106	5878.074	134.228	2.284
8 :	3.888	0.0815	12.389	0.3115	6165.071	135.039	2.190
9 :	4.769	0.0890	12.778	0.2867	6373.534	125.910	1.976
10 :	6.352	0.1065	14.771	0.3176	7893.473	149.621	1.896
11 :	6.868	0.1141	15.073	0.3163	7889.070	146.695	1.859
12 :	3.854	0.0893	16.121	0.3403	8088.456	153.386	1.896
0 :	3.457	0.0786	16.946	0.3698	83415.868	1655.634	1.985

Energiforbruk lastobjekt : 41393.332 MWh.
Totalt energiforbruk : 83415.868 MWh. Brukstid 4922 timer.
Total svingmaskin : 85071.492 MWh. Brukstid 4913 timer.
Totale tap : 1655.634 MWh. Brukstid 4477 timer.
Tap i prosent av last : 1.985 %

Max. last måned 1 time 17 : 16.946 MW

Alternative 4
Datasett : [redacted]. Beregningsår 2019.
Tidspunkt 2019-05-13 12:54:01. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV	MW	MVAr	
[redacted]	61.801 :	15.206	1.212	
Sum produksjon :		15.206	1.212	
Sum spenningsuavh. last :		14.906	3.615	
Sum spennings-avh. last :		0.000	-3.598	
Sum tap i linjeseksj. :		0.104	-0.187	
Sum tap i T2 :		0.053	1.074	0.015
Sum tap i TF :		0.140	0.303	0.048
Sum tap i F3 :		0.002	0.005	0.001
Sum elektriske tap :		0.300	1.195	0.064 (Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 47.29 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 2.01 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 6.28 %
Største belastning
Sterkest belastet linje : [redacted] : 88.77 %
Sterkest belastet T2 : [redacted] : 81.45 %
Sterkest belastet TF : [redacted] : 113.29 %
Sterkest belastet F3 : [redacted] : 39.58 %

2019 Mnd :	Min. effekt (MW) Last	Min. effekt (MW) Tap	Max. effekt (MW) Last	Max. effekt (MW) Tap	(MWh) Last	(MWh) Tap	(%) Tap
1 :	3.988	0.0923	14.906	0.3004	7618.505	142.798	1.874
2 :	3.667	0.0885	14.138	0.2845	6471.360	122.127	1.887
3 :	6.171	0.1061	12.383	0.2469	6854.861	124.395	1.815
4 :	4.971	0.0925	10.413	0.1987	5499.876	99.550	1.810
5 :	3.982	0.0831	8.897	0.1684	4770.157	89.125	1.868
6 :	3.505	0.0794	8.678	0.1768	4380.141	87.179	1.990
7 :	3.367	0.0784	8.942	0.1943	4629.654	96.250	2.079
8 :	3.800	0.0813	9.479	0.1997	4964.434	98.857	1.991
9 :	4.695	0.0889	10.288	0.2002	5381.892	98.805	1.836
10 :	6.282	0.1064	12.461	0.2437	6932.190	123.623	1.783
11 :	6.805	0.1139	12.973	0.2533	7052.745	125.414	1.778
12 :	3.735	0.0888	14.141	0.2762	7292.615	133.690	1.833
0 :	3.367	0.0784	14.906	0.3004	71848.428	1341.813	1.868

Energiforbruk lastobjekt : 41393.332 MWh.
Totalt energiforbruk : 71848.428 MWh. Brukstid 4820 timer.
Total svingmaskin : 73190.231 MWh. Brukstid 4813 timer.
Totale tap : 1341.813 MWh. Brukstid 4467 timer.
Tap i prosent av last : 1.868 %

Max. last måned 1 time 17 : 14.906 MW

Alternative 5

Datasett : [redacted]. Beregningsår 2019.
Tidspunkt 2019-05-14 11:23:43. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr		
[redacted]	61.801	:	16.340	1.704		
Sum produksjon		:	16.340	1.704		
Sum spenningsuavh. last		:	15.986	3.886		
Sum spennings-avh. last		:	0.000	-3.583		
Sum tap i linjeseksj.		:	0.152	-0.154		
Sum tap i T2		:	0.060	1.245	0.015	
Sum tap i TF		:	0.140	0.305	0.048	
Sum tap i F3		:	0.002	0.005	0.001	
Sum elektriske tap		:	0.354	1.401	0.064	(Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 47.66 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 2.57 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 7.46 %
Største belastning
Sterkest belastet linje : [redacted] : 117.80 %
Sterkest belastet T2 : [redacted] : 87.72 %
Sterkest belastet TF : [redacted] : 113.62 %
Sterkest belastet F3 : [redacted] : 39.67 %

APPENDIX B. APPENDIX B

Location C
Reference

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		16.707		0.	0.	555987.		555987.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 1

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		16.707		0.	0.	9991951.		9991951.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 2

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		16.707		0.	0.	2886150.		2886150.

APPENDIX B. APPENDIX B

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 3

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		16.707		0.	0.	4198814.		4198814.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 4

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		16.707		0.	0.	2421899.		2421899.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Location D
Reference
Datasett : [redacted]. Beregningsår 2019.
Tidspunkt : 2019-05-13 12:55:03. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr		
[redacted]	65.543	:	47.880	9.460		
Sum produksjon		:	47.880	9.460		
Sum spenningsuavh. last		:	46.792	11.236		
Sum spennings-avh. last		:	0.000	-6.487		
Sum tap i linjeseksj.		:	0.265	-1.492		
Sum tap i T2		:	0.250	4.742	0.057	
Sum tap i TF		:	0.563	1.437	0.127	
Sum tap i F3		:	0.010	0.024	0.005	
Sum elektriske tap		:	1.089	4.711	0.190	(Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 5.58 %
Spenningsfall høyspenning ref. trafo : [redacted] : 0.00 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 2.10 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 15.81 %
Største belastning
Sterkest belastet linje : [redacted] : 87.90 %
Sterkest belastet T2 : [redacted] : 134.62 %
Sterkest belastet TF : [redacted] : 399.49 %
Sterkest belastet F3 : [redacted] : 61.89 %

2019	Min. effekt (MW)		Max. effekt (MW)		(MWh)	(MWh)	(%)
Mnd :	Last	Tap	Last	Tap	Last	Tap	Tap
1 :	18.998	0.3486	46.792	1.0886	26351.316	536.335	2.035
2 :	17.308	0.3239	42.389	0.9309	21582.505	420.143	1.947
3 :	23.008	0.4171	35.590	0.7139	21789.449	405.639	1.862
4 :	18.508	0.3390	28.619	0.5290	16921.347	302.233	1.786
5 :	14.492	0.2820	22.501	0.3973	13718.560	246.061	1.794
6 :	12.484	0.2601	19.442	0.3452	11440.091	212.783	1.860
7 :	11.671	0.2529	18.315	0.3289	11147.339	211.384	1.896
8 :	13.374	0.2697	20.883	0.3689	12735.728	231.371	1.817
9 :	16.984	0.3143	26.413	0.4752	15616.988	275.055	1.761
10 :	22.984	0.4151	35.708	0.7136	21881.747	403.381	1.843
11 :	25.195	0.4608	39.061	0.8247	23138.779	442.265	1.911
12 :	17.735	0.3270	44.038	0.9961	24924.995	495.815	1.989
0 :	11.671	0.2529	46.792	1.0886	221248.843	4182.466	1.890

Energiforbruk lastobjekt : 147572.862 MWh.
Totalt energiforbruk : 221248.843 MWh. Brukstid 4728 timer.
Total svingmaskin : 225431.304 MWh. Brukstid 4708 timer.
Totale tap : 4182.466 MWh. Brukstid 3842 timer.
Tap i prosent av last : 1.890 %

Max. last måned 1 time 17 : 46.792 MW

Alternative 1

Datasett : [redacted] Beregningsår 2019.
Tidspunkt : 2019-05-13 12:58:13. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr		
[redacted]	65.543	:	55.181	13.805		
Sum produksjon		:	55.181	13.805		
Sum spenningsuavh. last		:	53.592	12.940		
Sum spennings-avh. last		:	0.000	-6.487		
Sum tap i linjeseksj.		:	0.671	-1.148		
Sum tap i T2		:	0.346	7.036	0.057	
Sum tap i TF		:	0.563	1.438	0.127	
Sum tap i F3		:	0.010	0.024	0.005	
Sum elektriske tap		:	1.590	7.351	0.189	(Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 5.63 %
Spenningsfall høyspenning ref. trafo : [redacted] : 0.00 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 5.01 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 16.63 %
Største belastning
Sterkest belastet linje : [redacted] : 265.99 %
Sterkest belastet T2 : [redacted] : 171.63 %
Sterkest belastet TF : [redacted] : 399.15 %
Sterkest belastet F3 : [redacted] : 61.85 %

2019	Min. effekt (MW)		Max. effekt (MW)		(MWh)	(MWh)	(%)
Mnd :	Last	Tap	Last	Tap	Last	Tap	Tap
1 :	19.406	0.3529	53.592	1.5896	29095.728	696.400	2.393
2 :	17.776	0.3286	50.189	1.5395	24430.441	588.681	2.410
3 :	23.328	0.4234	43.590	1.2646	25061.769	590.724	2.357
4 :	18.812	0.3440	36.219	0.9955	19894.087	448.543	2.255
5 :	14.785	0.2857	30.001	0.8147	16759.735	384.531	2.294
6 :	12.801	0.2636	28.242	0.8801	14882.211	382.028	2.567
7 :	12.012	0.2567	28.265	1.0069	15308.739	438.061	2.862
8 :	13.717	0.2739	30.583	1.0344	16737.851	449.226	2.684
9 :	17.309	0.3192	34.713	1.0169	18922.463	446.940	2.362
10 :	23.292	0.4214	43.408	1.2456	25086.025	585.369	2.333
11 :	25.475	0.4670	46.061	1.2962	25926.529	597.719	2.305
12 :	18.131	0.3309	50.638	1.4754	27498.599	638.287	2.321
0 :	12.012	0.2567	53.592	1.5896	259604.176	6246.509	2.406

Energiforbruk lastobjekt : 147597.862 MWh.
Totalt energiforbruk : 259604.176 MWh. Brukstid 4844 timer.
Total svingmaskin : 265850.680 MWh. Brukstid 4818 timer.
Totale tap : 6246.509 MWh. Brukstid 3930 timer.
Tap i prosent av last : 2.406 %

Max. last måned 1 time 17 : 53.592 MW

Alternative 2

Datasett : [redacted] Beregningsår 2019.
Tidspunkt 2019-05-13 13:01:56. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr	
[redacted]	65.543	:	54.735	10.983	
Sum produksjon		:	54.735	10.983	
Sum spenningsuavh. last		:	53.592	12.940	
Sum spennings-avh. last		:	0.000	-6.487	
Sum tap i linjeseksj.		:	0.345	-1.209	
Sum tap i T2		:	0.233	4.316	0.058
Sum tap i TF		:	0.555	1.399	0.130
Sum tap i F3		:	0.010	0.023	0.006
Sum elektriske tap		:	1.143	4.529	0.193 (Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 4.09 %
Spenningsfall høyspenning ref. trafo : [redacted] : 0.00 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 2.10 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 14.60 %
Største belastning
Sterkest belastet linje : [redacted] : 130.41 %
Sterkest belastet T2 : [redacted] : 95.68 %
Sterkest belastet TF : [redacted] : 391.55 %
Sterkest belastet F3 : [redacted] : 60.92 %

2019	Min. effekt (MW)		Max. effekt (MW)		(MWh)	(MWh)	(%)
Mnd :	Last	Tap	Last	Tap	Last	Tap	Tap
1 :	19.406	0.3435	53.592	1.1661	29095.728	553.437	1.902
2 :	17.776	0.3203	50.189	1.0376	24430.441	449.144	1.838
3 :	23.328	0.3976	43.590	0.8448	25061.769	441.124	1.760
4 :	18.812	0.3266	36.219	0.6419	19894.087	334.414	1.681
5 :	14.785	0.2746	30.001	0.5082	16759.735	280.151	1.672
6 :	12.801	0.2549	28.242	0.4947	14882.211	258.126	1.734
7 :	12.012	0.2482	28.265	0.5198	15308.739	273.680	1.788
8 :	13.717	0.2634	30.583	0.5530	16737.851	289.986	1.733
9 :	17.309	0.3033	34.713	0.6137	18922.463	316.088	1.670
10 :	23.292	0.3940	43.408	0.8359	25086.025	436.064	1.738
11 :	25.475	0.4358	46.061	0.9177	25926.529	464.203	1.790
12 :	18.131	0.3226	50.638	1.0531	27498.599	509.760	1.854
0 :	12.012	0.2482	53.592	1.1661	259604.176	4606.177	1.774

Energiforbruk lastobjekt : 147597.862 MWh.
Totalt energiforbruk : 259604.176 MWh. Brukstid 4844 timer.
Total svingmaskin : 264210.348 MWh. Brukstid 4825 timer.
Totale tap : 4606.177 MWh. Brukstid 3950 timer.
Tap i prosent av last : 1.774 %

Max. last måned 1 time 17 : 53.592 MW

Alternative 3

Datasett : [redacted]. Beregningsår 2019.
Tidspunkt : 2019-05-13 13:04:58. Hentet 2019-05-01.

Beregning for måned 1 (Virkedag) - time 17

Oppsummering :

	kV		MW	MVAr		
[redacted]	65.543	:	52.697	10.159		
Sum produksjon		:	52.697	10.159		
Sum spenningsuavh. last		:	51.552	12.429		
Sum spennings-avh. last		:	0.000	-6.487		
Sum tap i linjeseksj.		:	0.352	-1.263		
Sum tap i T2		:	0.220	4.019	0.057	
Sum tap i TF		:	0.563	1.437	0.127	
Sum tap i F3		:	0.010	0.024	0.005	
Sum elektriske tap		:	1.146	4.216	0.190	(Tomgangstap)

Største spenningsfall
Spenningsfall referert basisspenning : [redacted] : 5.55 %
Spenningsfall høyspenning ref. trafo : [redacted] : 0.00 %
Spenningsfall mellomspgenning ref. trafo : [redacted] : 2.36 %
Marginale tap
Høyeste marginale tap lastpunkt : [redacted] : 15.21 %
Største belastning
Sterkest belastet linje : [redacted] : 104.79 %
Sterkest belastet T2 : [redacted] : 91.20 %
Sterkest belastet TF : [redacted] : 399.33 %
Sterkest belastet F3 : [redacted] : 61.88 %

2019	Min. effekt (MW)		Max. effekt (MW)		(MWh)	(MWh)	(%)
Mnd :	Last	Tap	Last	Tap	Last	Tap	Tap
1 :	19.284	0.3436	51.552	1.1456	28272.404	548.246	1.939
2 :	17.635	0.3202	47.849	1.0293	23576.060	442.280	1.876
3 :	23.232	0.3992	41.190	0.8154	24080.073	432.362	1.796
4 :	18.721	0.3275	33.939	0.6166	19002.265	327.166	1.722
5 :	14.702	0.2753	27.751	0.4877	15847.383	273.251	1.724
6 :	12.722	0.2554	25.602	0.4663	13849.575	249.163	1.799
7 :	11.922	0.2487	25.265	0.4835	14060.319	261.357	1.859
8 :	13.630	0.2640	27.673	0.5142	15537.214	278.443	1.792
9 :	17.216	0.3043	32.223	0.5842	17930.820	307.326	1.714
10 :	23.199	0.3959	41.098	0.8091	24124.742	428.056	1.774
11 :	25.391	0.4380	43.961	0.8953	25090.204	457.993	1.825
12 :	18.012	0.3227	48.658	1.0542	26726.517	505.247	1.890
0 :	11.922	0.2487	51.552	1.1456	248097.576	4510.889	1.818

Energiforbruk lastobjekt : 147597.862 MWh.
Totalt energiforbruk : 248097.576 MWh. Brukstid 4813 timer.
Total svingmaskin : 252608.460 MWh. Brukstid 4794 timer.
Totale tap : 4510.889 MWh. Brukstid 3938 timer.
Tap i prosent av last : 1.818 %

Max. last måned 1 time 17 : 51.552 MW

APPENDIX B. APPENDIX B

Location D
Reference

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		108.419		0.	0.	4066214.		4066214.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 1

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		108.419		0.	0.	15628569.		15628569.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 2

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		108.419		0.	0.	6565623.		6565623.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Alternative 3

Fra	Til	Lengde (km)	Typebetegnelse	Anleggs-kostnad (kr)	Drifts-kostnad (kr)	Taps-kostnad (kr)	Taps-tid (timer)	Total-kostnad (kr)
I alt		108.419		0.	0.	6474483.		6474483.

Analyseperiode : 10 år
Kalkulasjonsrente : 4.50 % p.a.
Kostnad effekttap : 684.00 kr/kW
Kostnad energitap : 26.50 øre/kWh
Brukstid for tap : 4000 timer/år

Fornavn Etternavn

Oppgavens tittel

NTNU
Norwegian University of
Science and Technology