Norwegian School of Economics
Bergen, Fall 2017

End-User Flexibility and Network Investments

A Study on Utilizing End-User Flexibility to Defer Capacity Increasing Investments in the Norwegian Distribution Network

Magnus Buvik and Christian Nærup Børke

Supervisors: Endre Bjørndal and Mette Bjørndal

Master Thesis, MSc in Economics and Business Administration,
Energy, Natural Resources and the Environment

NORWEGIAN SCHOOL OF ECONOMICS

Abstract

The electricity value chain is facing several challenges. The transport sector is electrified, the electricity system digitalized, and generation decentralized. These trends transform the outlook of the electricity system. In the Norwegian electricity system, new consumption patterns and changing load profiles increase an already apparent need for reinvestment in the aging network infrastructure.

Increasing network capacity through investment in physical infrastructure is costly. Network operators model network capacity based on the few hours of year with peak demand, resulting in low utilization rates of excess capacity. Thus, network operators consider alternative ways of increasing capacity, which are less costly and more flexible. One such option is end-user flexibility provided from the demand side of the electricity system.

The analysis is based on an investment case provided by Skagerak Nett. We discuss different scenarios of utilization, flexibility volume and predicted load increase, and investigate how different compensation methods affect the benefits of utilizing end-user flexibility to defer investments. We find evidence that utilizing end-user flexibility to defer investments have cost saving effects under certain conditions, depending on flexibility volumes, utilization level and compensation method. Network operators can reduce costs by using end-user flexibility to manage malfunctions in transformers and peak loads in normal operations.

A key finding in the thesis it that the choice of compensation method has a large impact on the change in revenue cap and efficiency in the regulatory model. By issuing direct payments, end-user flexibility results in a lower efficiency, although a higher revenue cap, while redistribution of network tariffs have a marginal effect on changes in efficiency and revenue cap. Through redistribution of network tariffs, the network operator can defer investments without a notable increase in the revenue cap or change in efficiency. The results from the different end-user flexibility cases highlight some of the future challenges the regulator face in setting a regulatory framework for end-user flexibility.

Preface

This thesis was written as part of our MSc degrees in Economics and Business Administration with a major in Energy, Natural Resources and the Environment. The subject of the thesis embodies our inherent interest in technology, renewable energy and electricity markets.

The thesis was written as part of the project "*Fremtidens Nett*". We thank the reference group for their support, feedback and scholarship grant during the project.

We wish to thank our supervisors, Mette and Endre Bjørndal, for their support, guidance and constructive criticism throughout the process of writing our master thesis. It has been a pleasure working with two such dedicated and knowledgeable persons and researchers throughout the thesis. We also wish to thank Skagerak Nett, Glitre Energi, ADAPT Consulting and Energi Norge for giving us the opportunity to write about a very interesting and relevant topic in electricity system design.

In addition, we want to extend a special thanks to Eivind Gramme in Skagerak Nett for providing hours of valuable insight in the plethora of investment decisions network operators face and Patrick Narbel in ADAPT Consulting for his advice, depth of knowledge and guidance during the writing process.

Lastly, we wish to thank our family, respective girlfriends and friends for their patience, support and encouragement during our writing process.

Bergen, December 2017

Christian Nærup Børke

Magnus Buvik

Abbreviations

AMI	Advanced Metering Infrastructure
BRP	Balance Responsible Party
CPP	Critical Peak Pricing
CRS	Constant Returns to Scale
DEA	Data Envelopment Analysis
DER	Distributed Energy Resources
DG	Distributed Generation
DS	Distributed Storage
DSO	Distribution System Operator
EC	European Commission
EU	European Union
EV	Electric Vehicle
FiT	Feed-in-Tariff
GIS	Geographic Information System
GLS	Generalized Least Squares
IRR	Internal Rate of Return
kW	kilo Watt
kWh	kilo Watt hour
LIP	Load Increase Prediction
LS	Load Shifting
MILP	Mixed Integer Linear Programming
MVA	Mega Volt Ampere
MW	Mega Watt
MWh	Mega Watt hour
NL	Network Loss
NOK	Norwegian Krone
NPV	Net Present Value
OLS	Ordinary Least Squares
O&M	Operation and Maintenance
OI	Operational Income
OTC	Over-the-Counter
PS	Peak Shaving
PV	Present Value
PX	Power Exchange
RAB	Return on Asset Base
RC	Revenue Cap
RES	Renewable Energy Sources
RTP	Real Time Pricing
SFA	Stochastic Frontier Analysis
ToU	Time-of-Use
TSO	Transmission System Operator
TW	Terawatt
TWh	Terawatt hours
V2G	Vehicle to Grid
VoLL	Value of Lost Load
VRS	Variable Returns to Scale

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1. Introduction

1.1 Background

The unique physical properties of electricity define how electricity systems are designed. Since supply and demand must be perfectly balanced at all times, changes in demand must be matched by a similar change in supply. Furthermore, the electric system is built to be a redundant network. To ensure a reliable electricity supply and a sufficient safeguard against loss of power, network operators determine investments on the hours of peak load in a year. This often results in significant overinvestment in network capacity to ensure that reliability- and safety standards are met. Thus, optimizing investment decisions through smarter electricity system solutions is highly prioritized by Norwegian network operators.

The global trends of electrification, decentralization and digitalization increase the focus on innovative ways of planning and upgrading electricity system infrastructure. The trends introduce a plethora of new solutions to the network operator. To ensure a secure and stable supply of electricity, exploiting flexible resources and capabilities in the electricity system is highlighted as a promising attribute. However, utilizing flexible capacities in the electricity system is not a new concept. With a tight relationship between supply and demand, flexible generation and production has been implemented by large generators and producers at the transmission level of the Norwegian electricity systems for several years. Since technological advances mainly occur at the distribution level of the electricity system, there is a large, untapped potential in utilizing flexibility at the end-user level. This type of end-user flexibility can be used to shift consumption in periods of peak-load, mitigating the need for costly investments in network infrastructure.

With an increasing share of decentralized energy production, Europe´s highest EV penetration rate and an aging and mature infrastructure, new and cost-efficient ways of securing sufficient capacity is a priority. On the other hand, the Norwegian electricity system is well equipped for the challenges of the future. With 98% of all electricity production coming from flexible and renewable hydro power energy, mature and multinational markets with satisfying liquidity in the day-ahead, intra-day and real-time market and power tariffs being introduced by 2021, Norway could get a head start in terms of smart electricity infrastructure management compared to the rest of Europe.

1.2 Definition of End-User Flexibility

In current literature and research, flexibility from the demand side of the electricity system is represented by a range of terms. The most common terms for this kind of flexibility is demand-side flexibility, consumer flexibility or end-user flexibility. In this thesis, we will subsequently make use of the term *“end-user flexibility”*. Demand response and flexibility from the demand side of the electricity system is represented by the end-user offering or supplying it. The basis for our use of the term is that it is the most end-user centric.

THEMA Consulting (2015) define end-user flexibility as *the willingness to change volumes of electricity consumed for short or long periods as a response to market prices, price incentives in networks tariffs or other economic incentives*. We choose to adjust this definition to better emphasize the role of the end-user and define end-user flexibility as *the end user’s ability and capacity to shift, curtail or limit consumption.*

1.3 Scope

In this thesis, we analyze how Norwegian network operators can solve challenges related to capacity adjustments by utilizing end-user flexibility to defer investments in network infrastructure. We discuss how the network operator can compensate its end-users for offering their flexibility, and what impact end-user flexibility have on the Norwegian regulatory model. We do not discuss flexible load from industrial customers or local storage in detail. However, we cover research on topics in the close periphery of end-user flexibility such as local storage, the role of aggregators and power tariffs in the literature review.

1.4 Research Question

With a strong emphasis on how end-user flexibility deployment and current regulations interrelate, the thesis answers the following research question;

“Is end-user flexibility a feasible measure to defer capacity increasing investments in the distribution network, and what impact does end-user flexibility have on the revenue cap and efficiency of the network operator in terms of the regulatory model?”

The essence of the research question is to analyze how end-user flexibility can influence investment decisions of Norwegian network operators.

1.5 Thesis Structure

Chapter 2 briefly discusses the technical and economic aspects of the Norwegian power market. The chapter also cover three main trends influencing the future of electricity system design. This serves as a backdrop for the feasible application of end-user flexibility as an alternative to traditional investments.

Chapter 3 introduces the concept of end-user flexibility, discusses different types of end-user flexibility and map the potential of end-user flexibility in the Norwegian distribution network. Furthermore, we conduct a comprehensive review of relevant research and literature on end-user flexibility from both a technical, economic and market based perspective.

Chapter 4 discusses the latest legislative proposals from the EU, Norwegian regulations and the Regulatory Model. The chapter introduces how DEA-analysis is applied to network operators to determine the revenue cap in the Norwegian regulatory framework.

Chapter 5 introduces a case study on end-user flexibility in Skagerak Nett, a Norwegian Distribution System Operator. The case study presents different scenarios and alternatives where end-user flexibility is used to defer reinvestment in the distribution network. A sensitivity analysis for flexibility payments is also conducted

Chapter 6 analyzes how the Norwegian Regulatory Model affects the economic output of using end-user flexibility as in the Skagerak case. The analysis covers several aspects of the Norwegian Regulatory Model, and discusses how it can affect the deployment of end-user flexibility.

Chapter 7 concludes our thesis, and we discuss our results and propose topics for future research and projects related to end-user flexibility.

2. The Norwegian Electricity System

2.1 Technical Structure

New technologies are providing new challenges and opportunities to the traditional electricity power system. However, as electricity transmission is a capital-intensive industry, the changes are not adopted overnight. In this chapter, we will introduce the traditional structure of the electricity system and its components.

2.1.1 The Electricity Value Chain

How distribution systems are designed and operated varies between commodities. Electric power and electricity is a commodity that has technical properties that require a complex and specific design. Electricity is a continuous flow, as it is generated and consumed continuously, and is costly to store in large quantities (Ottesen, 2017). The consumption of electricity varies with a characteristic pattern during the hours of a day, the days of a week, and the months of a year. Electricity is regarded as an absolute necessity in modern society, so the security of supply is paramount. The electrical power system in Norway is typically divided into a central transmission network and a distribution network. The network that connects the two is often denoted as the regional transmission network. The transmission network is tasked with carrying high-voltage electricity over long distances, while the distribution network is tasked with distributing electricity to end-users and consumers at a much lower voltage (Sintef, 2017a). It is worth noting that some countries only use two network levels, commonly the transmission network and the distribution network. Figure 2-1 displays the Norwegian electricity power system.

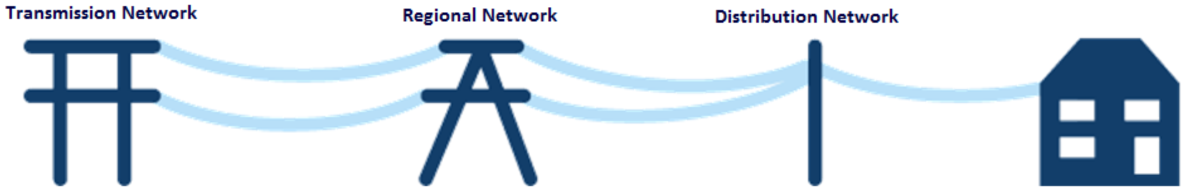

Figure 2-1: The Norwegian Electricity Network (Hafslund Nett AS, 2017)

The specific physical properties and features of electricity is reflected in the design of the electricity system. All transport systems have capacity constraints. This is no different in the electricity system. Since queues cannot form in the electrical power system, the network must have sufficient capacity to transport the highest possible load, known as peak load.

Today, the power line frequency in Norway is 50 Hz. Given the instantaneous nature of electricity, there must be a perfect relation between generation and consumption. If this relationship is imbalanced, the frequency will deviate from 50 Hz. Such imbalances can be critical to the system, causing unnecessary blackouts and system malfunction with critical consequences for the consumer and the society connected to the network. A stable electricity supply is crucial in a well-functioning society. Voltage quality is the part of the power quality concept that concerns the applicability of the voltage in the outlet. It is regulated to ensure that electrical equipment is functioning as intended, and the network is planned and dimensioned to satisfy voltage requirements (Sintef, 2017b).

2.2 Economic Structure

The technical structure of the Norwegian electricity market is closely tied to its corresponding economic structure. In the following sections, we introduce the roles and responsibility of different participants, the marketplaces in which they sell and purchase electricity, and how these roles are regulated and contractually determined.

2.2.1 Responsibilities

To ensure a reliable, safe and cost-efficient supply of electricity, a set of responsibilities and tasks are assigned to different participants in the electricity system. The responsibility of the Transmission System Operator (TSO) is to ensure operation and development of the transmission network, and to control frequency (Ottesen, 2017). In Norway, there is only one TSO, Statnett[1]. The Distribution System Operators (DSOs) own and operate the distribution networks within different regions, and are responsible for supplying end-users with electricity. There are 105 DSOs in Norway. The TSO and DSOs are responsible for transporting

[1] www.statnett.no/en

electricity and controlling overload and voltage. In Norway, entering a contract with a DSO is mandatory for consumers in order to receive electricity. Consumers are not free to choose the DSO, as operators have monopoly within their respective regions. The monopoly situation for DSOs and the TSO is a result of the deregulation process that occurred in the early 90s, which introduced new regulations.

However, a competitive market exists for the purchase and sale of electricity. Consumers are free to choose which retailer to buy their electricity from. When providing electricity to end-users, the retailer purchases electricity from generators at the Power Exchange (PX), or by off-exchange trading. The latter is known as over-the-counter (OTC) trading through bilateral contracts. The producers and DSOs pay the TSO for being connected to and using the transmission network, whilst consumers pay to the DSOs. The economic conditions of these payments are regulated through network contracts, mainly by network tariffs. Different contracts regulate the economic flows in the market, which can be divided into the wholesale market and the end-user market.

2.2.2 The Wholesale Market

The current market regime consists of several wholesale market places. The trading in the different markets are mostly in a sequential manner, determined by how close to real-time operation one trades. Figure 2-2 shows an overview of the market places moving towards real-time operations.

Figure 2-2: Different Market Places in the Sequential Wholesale Markets (Ottesen, 2017)

The main part of the wholesale market is the day-ahead market operated by Nord Pool[2]. In this market, buyers and sellers submit their bid curves for every single hour in the following day.

[2] www.nordpoolspot.com

The power exchange finds the prices that match demand (purchase) and supply (sales) hour by hour. Because of intermittent production and unplanned outages, participants can also trade in the intraday market to ensure balance. As opposed to the day-ahead market, which is cleared simultaneously for all hours of the day, the intraday market is cleared continuously. The bids and corresponding commitments are aggregated at zonal levels in both markets.

The bids from the day-ahead and intraday markets have an hourly resolution that ensures market balance in the planning phase. However, to ensure real time balance, the TSO organizes reserve markets with different time horizons. The reserves are primarily dispatchable, large generators that increase or decrease generation to stabilize the frequency. The market participants calculate and report deviations between planned and metered sale and purchase, after each single operational hour. The economic consequences of any imbalances are settled by the TSO in accordance to imbalance prices. Both the day-ahead, intraday and reserves market share the common objective of ensuring balance between generation and load in the most efficient way.

In addition to the day-ahead and intraday market, a PX also exists for trading in financial contracts. The exchange includes typical trading instruments such as futures, forwards and options, as well as contracts for difference (CfD). Nasdaq[3] is responsible for the operation of these markets in Norway. Market participants mainly use contracts to hedge price changes and manage risk, and the duration of each contract can vary from daily to several years.

2.2.3 The End-User Market

Most consumers purchase their electricity from a retailer. The terms are specified through a supply contract between each consumer and a freely chosen retailer. The retailer takes part in the wholesale market and is responsible for assuring balance on behalf of their group of consumers. This part of the market is denoted as the end-user side or demand side of the market. Contracts with fixed or variable prices are most common for consumers with periodically metered consumption. Variable price contracts usually have a fixed price for a period, for example based on the area prices (usually monthly prices). Another variable price contract follows the market price from the day-ahead market. Since prices vary hourly, the

[3] www.nasdaqomx.com/commodities

aggregated consumption for a consumer in a period is distributed, in accordance to a pre-defined profile, to calculate an average price per kWh. Larger consumers with hourly meters can have contracts that settles according to hourly consumption and corresponding hourly market prices. Changes in consumption metering are currently being undertaken by the industry, and will be discussed further later in this chapter.

Network contract with the local DSO have a different contract structure. These contracts mainly cover the DSOs expenses related to operation, maintenance and reinforcement of the distribution network. In addition to covering costs, the contracts aim to distribute expenses fairly among the network consumers. The Norwegian system operates with network contracts made up by multiple tariffs, dependent on the consumer's method of metering. Most households currently have periodical meters, and their payments consist of two parts: an energy fee and a fixed fee. The energy fee is usually a fixed price per kWh multiplied with metered consumption, whilst the fixed fee can be determined based on the size of the main fuse. For some consumers, especially the larger ones, there could be an additional fee based on peak power usage in a period. This fee is known as a power charge, and is usually made up by a fixed price per kWh/h per month.

2.3 Changes in the Norwegian Electricity System Structure

In a changing technological landscape, the electricity system is facing radical challenges. Developments happen fast, and affect both the technical and economic structure of the system. Several factors drive the changes in the electricity system. First of all, new climate goals promote increased renewable energy generation, which leads to new incentive regimes and regulations. Secondly, technology development and new electricity products lead to innovative appliances and more cost-efficient electricity services (Ottesen, 2017). Changes in market design, contracting and incentivizing initiatives provide a platform for increased end-user engagement and flexibility deployment. In this sub chapter, we present the three main trends electrification, decentralization and digitalization. These trends affect both the technical and economic structure of the electricity system. We cover how these trends affect electricity systems, and discuss some changes and developments that are specific for the Norwegian electricity system. Furthermore, we cover why these trends can lead to increased end-user flexibility deployment, and how they enable increased demand side participation. Key developments such as the electrification of society, decentralized generation, digitalization of the electricity system, advanced metering infrastructure, changing consumption patterns, new ways of contracting the end-user and the introduction of subscribed power tariffs will be highlighted.

2.3.1 Electrification of the Transport Sector

The shift from fossil fuels to renewable energy sources has led to an increased electrification of several sectors. The electrification of the road transport sector, where traditional combustion engine vehicles are replaced with electric vehicles is one such example. With developments in battery technology and charging infrastructure, the EV has become a viable option to combustion engine vehicles in the road transport sector. In Norway, favourable regulations and incentive schemes support a growing EV fleet (Figenbaum, Assum, & Kolbenstvedt, 2015). With a growing fleet of EVs, simultaneous charging will put stress on the network infrastructure. Since EV-owners typically charge their vehicles at similar times, e.g. when arriving at work in the morning or at home in the evening, charging often takes place at times of peak load. This results in the need for network infrastructure investments. The road transport sector is not the only transport sector facing electrification. New, electrical ships and ferries operating along the Norwegian coast is a substantial challenge for the current Norwegian electricity system. Charging infrastructure in harbours and docks leads to an increase in power output that requires investments in the network infrastructure from the counties Troms to Rogaland according to a report by NVE (2017a). Estimates from NVE concludes that by 2030, 115 transformers will experience overload. Electrification of transport are estimated to be directly responsible for investment needs related to such overloads in 33% of these overloads.

In the same report from 2017, NVE highlights that the electrification of the Norwegian transport sector can lead to a reduction in CO_2 emissions by 6 tonnes in 2030. This amounts to 10% of total CO_2 emissions in Norway. The basis for these estimates is that electrification of the transport sector will reduce the energy consumption from 55 TWh in 2016 to 45 TWh in 2030 (NVE, 2017a). However, the simultaneous nature of EV charging might lead to overload and voltage problems in the distribution network and at charging sites (Ottesen, 2017). Thus, the electrification of the transport sector might increase the need for investments, an investment need that can be lowered by flexibility from the demand side and end-users.

2.3.2 Decentralization of Electricity Generation

The traditional way of generating electricity is through large, centralized power plants. To increase the share of renewable energy in the network, incentivizing end-users to generate local, distributed energy is highlighted as a viable option. Such decentralized generation is often denoted *Distributed Generation* (DG) and consists of *Distributed Energy Resources* (DER). DER can be defined as *electric power generation units connected directly to the distribution network or connected to the network on the customer side of the meter* (Ackermann, Andersson, & Söder, 2001). Typically, DER are small-scale generators with a generation capacity of 3 kW up to 10 MW (Viral & Khatod, 2012). The most common DER are wind turbines or solar photovoltaic (PV) panels. Kondziella & Bruckner (2016) highlights that these generators are often intermittent and uncontrollable. Furthermore, forecasting the electricity generation is difficult due to volatile temperature and weather patterns in many areas. Developments in local storage solutions and battery technology enables the decentralization and distribution of electricity generation. Since DER are intermittent, batteries can enable local production to reduce the pressure on the distribution network (Qvartz Consulting, 2017). Storage systems at the distribution side of the network is often denoted *Distributed Storage* (DS), and includes home batteries, network batteries and EV batteries. These batteries can discharge when additional generation is needed and charge when additional load is needed (Ottesen, 2017). Key advantages with DS is the ability to store renewable, intermittent energy to be used at a later more beneficial stage. This can help reduce peak loads (International Energy Agency, 2014). The decentralization of electricity generation offers new possibilities for the end-user in terms of purchase and sale of electricity. In Norway, the technological development and rise of companies like Otovo, who sell solar PV solutions in regular electronics stores, turn the traditional passive consumer into an economically motivated and active *prosumer* (Dagens Næringsliv, 2017; Ottesen, 2017). Grijalva, Costley & Ainsworth (2011) define a prosumer as *an entity that can do at least one of the following: consume, produce or store electricity.* By producing parts of their own demand, prosumers can sell their surplus electricity back to the network and thus provide flexibility.

2.3.3 Digitalization of the Electricity System

Several digital technologies affect the trends in electricity systems design and operation. Technologies such as block chain, artificial intelligence and machine learning are applied extensively to electricity markets in research projects (PwC, 2015). Two-way communication between end-users and the network operator through IoT-devices is also creating new business models. Internet of Things (IoT) can be defined as *a global infrastructure for the information society, enabling advanced services by interconnecting physical and virtual things based on existing and evolving interoperable information and communication technologies* (Internation Telecommunication Union, 2012). By integrating electricity systems with IoT-technology and information systems, the intelligence in the network increases. Extensive monitoring, communication and predictive analytics can be applied to both network operation and investment decisions. These types of networks are often denoted *Smart Grids*. The European Commission (2006) define a Smart Grid as *an electricity network that intelligently integrate the actions of all users connected to it - generators, consumers, and those that do both – prosumers – in order to efficiently deliver sustainable, economic and secure electricity supplies.* An illustration of how a Smart Grid interconnect electricity and information systems is provided in Figure 2-3 below.

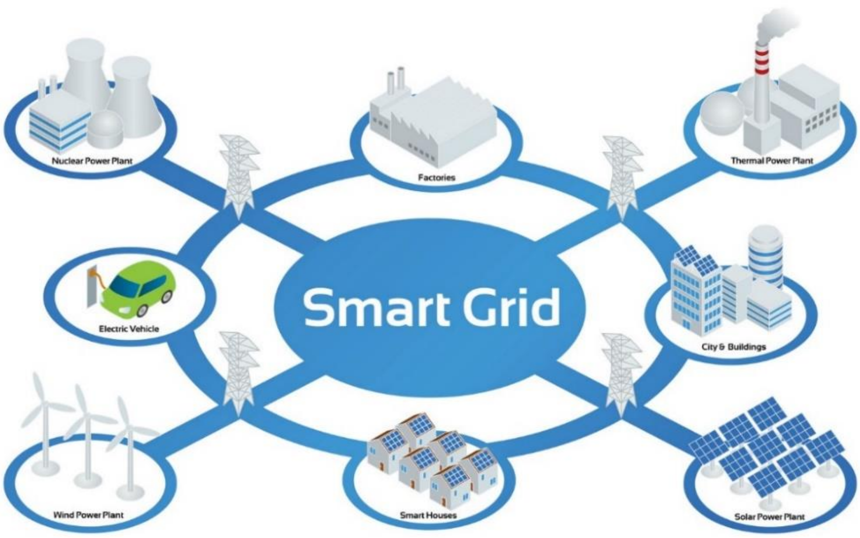

Figure 2-3: A Smart Grid (European Technology Platform for the Electricity Networks of the Future, 2016)

Some of these new technologies lead to negative consequences for the electricity system. However, integrating end-users, new technologies and the electricity system have benefits that can outweigh these negative consequences. End-user flexibility is highlighted as a technology that can help balance the fluctuations of variable renewable energy sources and facilitate penetration of renewable energy sources in the electricity system. (O'Connell, Pinson, Madsen, & O'Malley, 2014).

All Norwegian electricity customers will have new and smarter metering infrastructure installed by 1.1.2019 (NVE, 2017b). This metering infrastructure is denoted *Advanced Metering Infrastructure* (AMI), and network operators are responsible for the deployment and installation of the new meters. The main objective with AMI is obtaining more precise and detailed information about consumption patterns, load profiles and the general state of the electricity system. With more precise and detailed information about their network, network operators can reduce O&M costs, correct malfunctions and errors in the network faster and better model future investments on the current demand and supply of electricity (NVE, 2017b). Ottesen (2017) highlights that AMI also introduces the possibility to meter several parameters such as reactive power and voltage, two-way communication with the DSO and adds an open interface for third parties, such as aggregators. The end-user will benefit from updated information about their consumption, making energy efficiency measures easier to implement. NVE estimates the total investment costs of the AMI-deployment to 10 bn. NOK, with an average increase in network tariffs of 300 NOK per household (NVE, 2017b).

2.3.4 New Load Profiles and Consumption Patterns

The introduction of new technologies, local generation of renewable energy, EVs and smart home appliances results in new load profiles and changing consumption patterns in the Norwegian electricity system. Increased electricity dynamics, larger peaks and reverse flows are some of the challenges DSOs are facing in the future electricity system. These challenges might have adverse consequences for the distribution network (Pudjianto, et al., 2013). Eurelectric (2013) highlights that unpredictable and bi-directional network flows as well as greater variations in voltage challenge the distribution network.

In Figure 2-4, Ottesen (2017) displays how the aforementioned trends affect the load profile of a Norwegian household throughout a day. The traditional load is derived from a research report on average, hourly electricity consumption in a Norwegian household by Kipping & Trømborg (2015). The load profile highlights the traditional morning and afternoon peaks when households perform their morning routines and come home from work, school or other occupations respectively. By adding EV charging at 3.7 kW to the traditional load profile, Ottesen (2017) adds that this doubles the peak load in the afternoon. An increasing share of Norwegian end-users are interested in generating and producing their own electricity through solar PV-panels (Sysla, 2016). The traditional load profile is severely transformed when introducing generation from solar panels in the lower left figure. The maximum generation is in the middle of the day, which does not correspond well with the traditional load profile (Ottesen, 2017). The short sags and surges in the load profile is due to decreased and increased generation when clouds pass by. Ottesen (2017) summarize the net result of these new technologies and appliances in the lower right corner. At some points of the day, the household delivers its surplus electricity back to the distribution network. Furthermore, spikes are present in the morning and afternoon, coinciding with the use of heating appliances and EV charging.

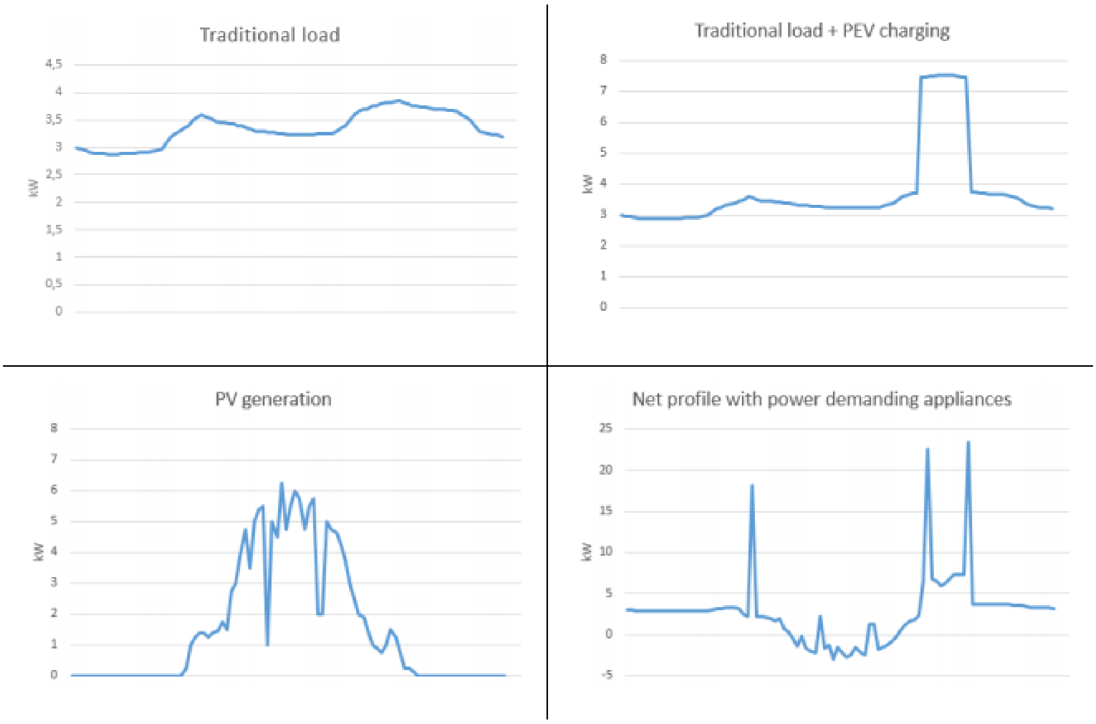

Figure 2-4: Load and Generation Profiles for a Norwegian Household Over the Course of One Day (Ottesen, 2017)

The changes in load profiles and consumption patterns require increased distribution network capacity and reserves in case of malfunction. Typically, this is solved by investing in new network infrastructure. This is a costly approach and additional capacity often have low utilization levels (Teng, Aunedi, & Strbac, 2015).

2.3.5 New Flexibility Contracts

The flexibility services of the future are highly dependent on new flexibility contracts and compensation schemes that consider both end-users and network operators. Although implementing end-user flexibility is technically possible, incentives must be present for the end-user to participate in this market. Thus, enabling end-user flexibility is not only about creating sufficient technical mechanisms, but also providing the right economic motivation or moral incentive through correct contract design (Ottesen, 2017). Two possible flexibility contract types are direct and indirect control.

Indirect control contracts are one option in end-user flexibility contracting. In this case, the DSO sends a price signal to the end-user, whereas the end-user responds to this price signal according to their preferences. This type of control mechanism is often referred to as price-based or decentralized, since the end-user ultimately decides the outcome through their consumption pattern. The most common indirect control mechanisms are Time of Use (ToU), Critical Peak Pricing (CPP) and Real Time Pricing (RTP). Time of Use (ToU) divides the day into time slots, and each time slot has a price attached to it for use of electricity. The time slots are usually seasonal and covers broad blocks of the day. When ToU is used as a dynamic way of pricing electricity, end-users are notified in advance. Prices can be defined as average prices for different time slots, but directly indexed to the day-ahead spot price (Eurelectric, 2017). With Critical Peak Pricing (CPP), the price rate increases throughout a pre- determined number of hours a year when wholesale prices are higher than usual (Eurelectric, 2017). CPP is typically applied when utilities observe emergencies or events that cause specified periods of higher prices. There are two common options of CPP application. The first option is predetermined surges in prices over a given time if events occurs. The second option is a surge in prices over a variable time when the electric network needs to reduce and shift loads (Smartgrid.gov, 2017). Real Time Pricing (RTP) is the most rigid and complex of the indirect control contracts. When utilizing RTP, electricity prices vary on an hourly basis in accordance with the wholesale market price (Schreiber, 2015). Thus, RTP passes the cost of electricity directly on to the customer. CPP and RTP are examples of what is called dynamic electricity pricing, where end-users and utilities take advantage of smart network flexibility. Since prices are predetermined in ToU, this cannot be defined as a dynamic electricity pricing mechanism. However, all three of these market mechanisms are reliant on AMI and smart meters, and represents viable design mechanisms to promote increased flexibility at the end-user level. Ottesen (2016) highlights that indirect control contracts incentivize the end-user to flatten their load profile but have certain disadvantages. End-users typically adapt when their flexibility is not needed, and indirect contracts do not give a guaranteed response when flexibility is actually needed. Furthermore, indirect control contracts give the same price signal to all customers, regardless of the network situation. Lastly, indirect control contracts are often perceived as a penalty. This might put end-users off, subsequently reducing the flexibility potential in the network. According to microeconomic theory, the most economically efficient form of indirect control contracting is RTP, since it incentivizes end-users to consume their electricity when their marginal benefit is greater than the instantaneous marginal cost of power production (Borenstein, 2005; Caramanis, Schweppe, & Tabors, 1983; Holland & Mansur, 2006).

The second option in end-user flexibility contracting is *direct control contracts*. Ygge & Ackermans (1996) denotes this contract type as centralized control, and highlights that a central agent remotely controls end users' equipment. This central agent can be an aggregator or a DSO. We discuss the role of the aggregator in chapter 3. To perform the remote control of equipment, the central agent must have a legal contract with the end-user. With a direct control contract, end-user flexibility can be activated when needed. Furthermore, activation of end-users residing in specific locations is possible. In this respect, direct control contracts are a more targeted way of utilizing end-user flexibility. Ultimately, the end-user are more likely to perceive the direct control mechanism as a reward since they are compensated according to their flexible contribution (Ottesen, 2016). A key drawback with direct control contracts is that they are technologically intensive, as the end-user must have the sufficient equipment and infrastructure to enable direct control. Furthermore, the roles and responsibilities shared by the network operator and end-user must be clearly defined. Designing attractive business models is a third problem with direct control contracts (Ottesen, 2016).

2.3.6 Subscribed Power Tariffs in Norway

A recent development in the Norwegian electricity system is that the power output has increased more than the electricity consumption. With a growing population, the need for electricity is increasing. However, more energy efficient appliances and better isolation of new buildings reduces the growth in electricity consumption at the cost of higher power output, even though the population is growing. The power output is increasing faster than the electricity consumption due to power demanding appliances and an increasing share of EVs. These appliances have a highpower output over shorter times (NVE, 2017c).

NVE wants the network tariff to reflect the cost drivers in the network. Thus, redesigning the network tariff to reflect the cost structure in the network is important. Consumption patterns and the decisions of end-users clearly affect costs, and NVE wants to incentive end-users to utilize the network more cost-efficiently. Furthermore, a subscription based power tariff makes it easier to implement new technologies and innovative market places that promote network efficiency. With the deployment of AMI, network operators are able to calculate network tariffs based on consumption per hour, kWh/h. Power tariffs are pricing how much electricity an end-user is consuming per hour. By introducing a power tariff, NVE aims to reduce peak loads. This results in a reduction in network infrastructure investments and deferment of these investments. The proposed network tariff is based around a power subscription, and can be expressed as:

$$Network\ Tariff = Load\ Subscription + \ Excess\ Load\ Consumption\ + Load\ Transport\ Loss$$

In this network tariff design, the end-users pay an increased price for all *Excessive Load Consumption* exceeding their *Load Subscription*. In addition to paying for their subscribed power output and excess load consumption, the end-users pay for *Load Transport Loss*, which is denoted as an *energy variable*. This variable accounts for the costs end-users impose on the network by consuming one extra unit of kWh (NVE, 2017c).

Although NVE has not yet decided the specific design of subscribed power output as the preferred network tariff, a change in network tariff over the next years can be expected. Since end-users must be able to identify which subscription is feasible for their respective power output, it is likely that the full-scale deployment of AMI will serve as a learning ground for end-users to understand their consumption and power output. Furthermore, a power tariff enables new, innovative flexibility solutions, as end-users grasp the concept of better load management such as load shifting.

3. End-User Flexibility

In this chapter, we present the concept of end-user flexibility in depth. We discuss why end-user flexibility is an alternative to investments in infrastructure for network operators, define explicit and implicit end-user flexibility as well as discussing relevant application areas. Furthermore, we introduce the three main types of end-user flexibility, and their differences. In the second part of the chapter, a comprehensive literature and pilot review is conducted.

3.1.1 Planned Investments in the Norwegian Electricity System

In the Reiten-report “A Better Organized Electricity Network” (2014), four, key drivers for estimating future investment needs in the Norwegian electricity system is identified. The first driver for increased investments is the technical state of current infrastructure. Substantial network investments occurred in the 1970 and 1980s, and parts of the current infrastructure is approaching the end of its technical lifetime. Ensuring that the overall state of the electricity system is able to handle future electricity demand, load profiles and new appliances is important. Thus, the Reiten-report highlights that substantial investments is still needed at all network levels in the years to come.

The second driver for increased investments in the electricity system is population growth, urbanization and increased electricity demand. According to the Reiten-report, Norway has one of the highest population growth rates in Europe. A growing population increases electricity demand, thus resulting in a need for new network infrastructure to respond to this increase in demand. Furthermore, population growth rates are higher in urban areas and large cities, meaning DSOs in these areas will have higher investment needs than the ones in more remote areas (Reiten, et al., 2014).

A third driver for investments in the electricity system is compliance with national- and international climate goals through increased use of new energy carriers. Although the Norwegian electricity system has benefitted from flexible hydropower, the increased use of renewable power generation challenges the electricity system. Prosumers that sell their energy back to the network will also increase the complexity of the electricity system, highlighting the need for investments (Reiten, et al., 2014).

The fourth and last driver the Reiten-report highlights is load increase predictions. The electrification of the transport sector, new power demanding home appliances and the introduction of AMI all affect the future load demand, and challenge the network in several ways. The electrification of the transport sector is a critical challenge for the current Norwegian electricity system. Historically, combustion engines and fossil fuels have been used in vehicles, leading to an electricity system that were not dimensioned for a full electrification of this sector. Areas in close proximity to transport centers such as harbors, train- and bus stations will experience increases in power demand with the electrification of the transport sector. This leads to a substantial investment need for capacity increasing investments at the distribution and regional network level.

In addition to these key drivers, the general advances in technology have led to discussions of a “smarter network”, where end-user flexibility and flexibility from the demand side is a key component. By involving the end-user through a third-party flexibility aggregator, network operators can access flexibility volumes that are currently hard to obtain for the specific times when capacity is needed. Since changing consumption patterns challenge the network capacity, flexible end-users can help alleviate peaks and balance demand and supply.

In the period from 2016 to 2025, NVE has estimated investment costs of 33 billion NOK and 15 billion NOK in the high-voltage and low-voltage parts of the Norwegian distribution network respectively (NVE, 2016). Since investments at the distribution level of the electricity system is based on the specific hour in a calendar year where the power output and consumption is estimated to be at its highest, load increase predictions play a vital part in the investment decision network operators undertake. By utilizing end-user flexibility and smarter investment solutions, network operators aim to optimize their network performance while reducing the overall investment costs in new infrastructure through better peak load management.

3.1.2 Implicit and Explicit End-User Flexibility

The design of power tariffs, pricing areas and forced up- and down regulation are all measures to increase end-user flexibility deployment (THEMA Consulting, 2015). A common approach in research and literature is distinguishing between *implicit* and *explicit* end-user flexibility. While *implicit end-user* flexibility implies that the end-user adjusts their consumption patterns according to price signals, *explicit end-user flexibility* is characterized by incentivizing end-users to trade their flexibility in an organized market place (Ramos, et al., 2013).

Implicit end-user flexibility is often referred to as price-based flexibility, and implies that end-users adjust their consumption to price signals or track variations in price through apps or appliances. Common price signals are time based power tariffs such as ToU and RTP, or demand based power tariffs such as CPP, which raises the price of electricity when the peak demand is high (EG3, 2015). An example of an appliance that help end-users adjust their consumption is the application *SmartLiv* by the Norwegian DSO Ringeriks-Kraft Nett. The application enables end-users to observe their consumption through hourly metering, track shifts in consumption patterns over time and compare their consumption with neighbors and other end-users (Ringeriks-Kraft Nett AS, 2017). Another vital aspect of implicit end-user flexibility deployment is a high time granularity of metering. Typically, end-users can be billed per hour of electrical usage. The monthly price will then be calculated by multiplying the consumption per hour with the spot price from Nord Pool Spot for that specific hour (Lyse Elnett AS, 2017).

Explicit end-user flexibility embodies flexibility that can be traded in a market place. With explicit end-user flexibility, the end-user is compensated through a contract that enables manual or automatic shifts in their electricity consumption. One of the key drivers for the deployment of explicit end-user flexibility is well-defined and liquid flexibility markets. Since participation in such markets include substantial transaction costs, end-users are typically unable to offer flexibility volumes in this market without a subsidiary. Moreover, volumes produced from a change in consumption from a single end-user does not satisfy the required bid size. A key driver in explicit end-user flexibility deployment is the establishment of aggregators who aggregate flexibility and offer specific flexibility services to the market on behalf of the customer.

The main goal of flexibility services is to enable the end-user to take part in the market place and reduce their electricity costs by offering flexibility to the system through their consumption patterns. In this respect, flexibility services play a vital role in balancing supply and demand in the electricity system. Ultimately, increased end-user flexibility can result in lower electricity prices, which even benefits non-flexible end-users (U.S. Department of Energy, 2017).

Both technology and end-user preferences influence end-user flexibility deployment. Specific flexibility services can only be provided by explicit end-user flexibility, while other services are only possible with implicit end-user flexibility. Explicit end-user flexibility is a measurable resource. Hence, it can be incorporated in system adequacy assessments in a similar way to generation (SEDC, 2016). Implicit end-user flexibility shifts the commitment to the end user's behavioral patterns. With the deployment of AMI and increasing customer participation, SEDC highlights that implicit end-user flexibility has a large untapped potential.

3.1.3 Utilizing End-User Flexibility in Investment Decisions

Increased intelligence in the network impose new challenges and tasks for DSOs, but also new benefits and opportunities (Reiten, et al., 2014). Increasing the information access and receiving it closer to real time will help DSOs achieve better planning of investments and operations. The Reiten-report highlights the ability to reduce or postpone investments, as one of the main benefits of more active control. Investments that can most easily be deferred are mainly reinvestments in existing infrastructure and components.

The need for large investments in the industry increase the importance of cost efficient DSOs. Investments must be thoroughly evaluated to prevent inefficient investments in the network. With the implementation of AMI at all end-user levels, network operators can monitor specific components and make better predictions of future load demand. Investments can be optimized based on load profiles, bottlenecks and components status. Maintenance can be planned according to real time need instead of general inspections, reducing uncertainty and increase utilization of existing components.

Flexibility from large industrial players is actively used by the TSO to balance the electrical networks. For imbalances in the distribution network, there is a lack of measures to adjust production or consumption. Intelligent equipment in the network make it possible to utilize end-user flexibility from smaller electricity consumers, such as households and offices, enabling them to compensate non-flexible consumers in times of scarcity.

End-user flexibility can be used to handle peak loads and function as a reserve in case of component malfunction. In the case provided by Skagerak Nett, which will be presented and discussed in chapter five, we look at two overlying scenarios. In the first framework, end-user flexibility is used in case of malfunction in transformers in the distribution network. In the second scenario, end-user flexibility is used both in case of malfunctions and to handle peak loads in normal operations. The scenarios represent two possible use areas the industry consider valuable and feasible. Both scenarios can help defer capacity-increasing investments. Load increases in the network and component malfunctions have traditionally been addressed by direct investment in capacity increasing assets and reserves, and end-user flexibility is presented as an alternative technology.

3.1.4 Types of End-User Flexibility

End-user flexibility have several areas of use. The three most common types of end-user flexibility are peak shaving, energy conservation and load shifting (Sæle & Grande, Market based solutions for increased, 2005). The base case scenario without utilizing end-user flexibility and the three types of end-user flexibility is displayed in Figure 3-1.

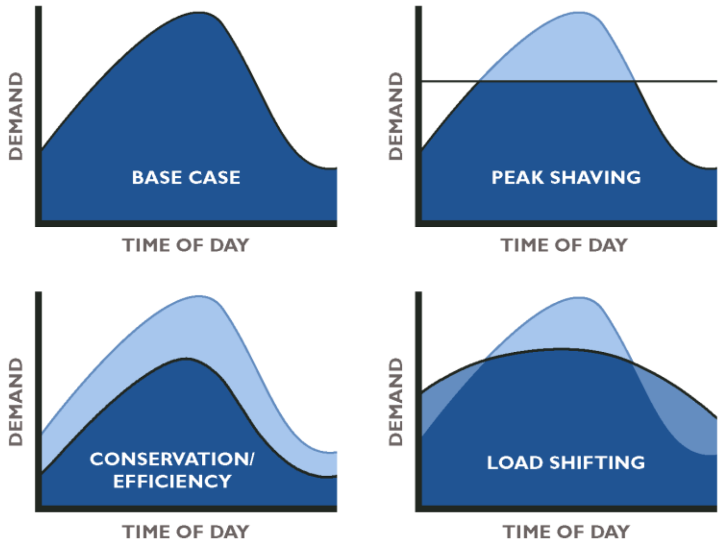

Figure 3-1: Base Case, Peak Shaving, Conservation and Load Shifting (U.S. Agency for International Development, 2017)

According to Sæle and Grande (2005) peak shaving can be defined as reducing the electrical load of a particular system during a period of peak demand. Peak shaving can be done by turning off or disconnecting loads. The loads chosen are often slow loads, such as water boilers, EV charging and heating. Energy conservation implies scaling down and reducing electricity consumption in a designated period, e.g. a day, a week or a month. This typically occur in situations where there are temporary energy shortages. Since end-users have a relatively homogeneous demand over time, loads will often be shifted in time rather than completely shaved. Load shifting takes place when the customer shifts their electricity consumption in time. An example of this could be shifting consumption at hours with high electricity prices due to peak load, to consumption at hours with lower electricity prices due to less load demand (Sæle & Grande, 2005).

3.2 Literature Review

3.2.1 Introduction

To evaluate the feasibility of using end-user flexibility to postpone and shift capacity investments in the network, it is necessary to take a step back and consider the overall conditions. By discussing current research and literature on key topics on end-user flexibility, we cover trends in both technological and economic aspects. Current academic and professional discussions revolve mostly around the overall market design of end-user flexibility or flexibility provision from large, industrial generators. The literature review includes selected research on several topics related to end-user flexibility deployment in the distribution network and as an alternative to network infrastructure investments.

3.2.2 Handling Peak Demand with End-User Flexibility

In recent years, electricity market research has focused on making smarter and more cost-efficient investment decisions to handle capacity problems. In this regard, end-user flexibility is promoted as a promising way to deal with new load profiles, an increasing share of renewable energy sources and a changing energy demand landscape (Papaefthymiou, Grave, & Dragoon, 2014). However, it is necessary to design sufficient incentives and regulatory schemes to enable active load management of end-users (Clean Energy Ministrial, 2014). Schmalensee (2011) highlight the fact that all end-users that engage in contracted down-regulation of demand should be explicitly rewarded through sufficient incentives.

When assessing how to handle peak demand through end-user flexibility deployment in the distribution network, large volumes of end-user flexibility have been hard to obtain for research and modelling purposes. Researchers at ETH Zürich (Geidl, et al., 2007) solved this by studying the interrelation between electrical and thermal energy systems in buildings called *Energy Hubs*. These Energy Hubs relied on various energy input variables such as electricity, natural gas and heating. Furthermore, the Energy Hubs included storage and conversion properties, and produced output services that complied with certain loads such as electricity, heating and cooling (Geidl, et al., 2007).

Bozchalui et al., (2012) propose a Mixed Integer Linear Programming (MILP) optimization problem to the Energy Hub concept. The problem minimizes energy consumption, cost of energy, emissions and peak load. Specific end-user preferences and comfort levels are also taken into account. The application of the model on a household in Ontario, Canada resulted in up to 20% savings on energy costs and a 50% reduction in peak demand, all while satisfying the designated preferences and comfort levels of the end-user.

Strbac et al., (2008) discuss the major benefits and challenges of end-user flexibility in the UK power system. Key benefits include improved management of the demand-supply balance in electricity systems with an increasing share of renewable energy, deferring new infrastructure investments, simplifying outage management and relieving congestion in distribution substations. The use of demand response to better utilize infrastructure capacity is proposed as a large benefit. Strbac highlights the lack of ICT systems to support demand response and end-user flexibility deployment, immature and insufficient market design as well as lacking provision of incentives from OFGEM, the UK regulator.

3.2.3 Applying End-User Flexibility to Investment Decisions

The traditional approach to expanding capacity in the network is investing directly in physical infrastructure. Hoff, Wenger and Farmer (1996) highlights that demand-driven investments in increased capacity often results in a period of excess capacity. Furthermore, the cost benefit of deferring investments results from the specific investment costs and time they are deferred (Wang, et al., 2008). In an early study, Román, Gómez, Muñoz, & Peco (1999) proposes the use of geographic information systems (GIS) to model and plan network investments alongside roads and transport infrastructure. They conclude that this approach reduced barriers and infeasibilities in network planning.

El Khattam, Hegazy & Salama (2005) proposes a new model for network investments where the positioning and sizing of distributed generation (DG) sources are optimized. Several investment alternatives are tested, including expanding an existing substation and adding new feeders to purchasing power from an existing intertie to meet load demand growth. They conclude that optimizing this positioning and sizing can result in a 20% reduction in investment costs.

Méndez et al., (2006) also studies the impact of DG on deferring distribution network investments. A main result from their research is that with 0% penetration of DG, load increases in the distribution network can grow by 171.4 % until reaching an overload probability of 0.5%, while a 30% penetration of DG allows a load increase of 196.4% until reaching an overload probability of 0.5%. They also highlight that DG plants with solar PV generation allow higher load growths before making network reinvestments than DG plants with wind power generation. This is due to a higher randomness in wind energy production.

Piccolo & Siano (2009) discusses how DG can serve as an alternative distribution planning option by providing opportunities to capture the deferment benefit. They highlight the regulatory side of the issue and conclude that European legislations must be revised to make DG a feasible option to investments in infrastructure. By obliging network operators to require for local power generation as a direct alternative to network infrastructure reinvestments, the deferral benefits of DG can be reaped.

Pudjianto et al., (2013) introduces smart control to minimize distribution network reinforcements. They simulate how network infrastructure investments differs in a business-as-usual scenario and a Smart Grid scenario. Without smart infrastructure management, they estimate that between 2010 and 2050, the total distribution network reinforcements in the UK will amount to £36 billion. By applying smart charging of vehicles, smart heat pumps and optimized control of network voltage regulators, they conclude that there is a substantial savings potential in infrastructure investment costs. The report does not explicitly estimate any savings.

Spiliotis, Ramos and Belmans (2016) analyze how end-user flexibility can be used to solve capacity problems and defer physical network expansions in the distribution network. They develop and define the FlexMart model, which enables the DSO to purchase end-user flexibility offered by residential end-users. The model works as a long-term planning tool and provide an optimal combination of physical expansions, flexibility deployment and dispatch to reassure capacity needs in network operations are met.

3.2.4 Quantifying the Technical Potential of End-User Flexibility

The technical potential can be described as the amount of flexibility end-users can offer to the electricity system. Several research projects have studied and quantified the flexibility potential in Norway and the Nordic region.

An early study conducted by Meland et al., in 2006, estimated the technical potential of end-user flexibility by considering electricity volumes that could be replaced by other energy carriers. This study focused on office buildings, residential homes and industrial complexes. The flexible load is estimated partly by assuming plausible changes in energy carriers and by assuming an average time of 2000 hours each year. The study concluded that by switching energy carriers, 2700 to 4000 MW of flexibility were made available.

In a SINTEF-study from 2010, Sæle & Grande estimates the technical potential in Norwegian households by analyzing results from a pilot by the DSO Malvik Everk. The results from the pilot was an estimated reduction in power output of 1 to 2,5 kWh/h per end-user, depending on whether they were equipped with hot water boilers or water based residential heating systems respectively. By scaling these results based on a 50% acceptance rate of automated control of warm water tanks nationally, the study concluded that the technical potential in these Norwegian households amounted to 1000 MW.

Xrgia & EC Group (2012) estimated the technical potential of end-user flexibility in the Norwegian counties of Oslo and Akershus. Based on electricity consumption statistics, estimates of future power outtakes and qualitative assessments of end-user flexibility deployment, an estimated technical potential of 550 MW in Oslo and Akershus was found.

The technical potential of end-user flexibility will also be influenced by a growing fleet of EV´s. In the report "Does the electrical network have enough capacity to include electrical buses, ferries and cars?" from 2017, NVE estimates that each additional EV represent an increase of 0.7 kW in peak demand. The current fleet of roughly 125 000 EVs accounts for 100 MW in potential flexibility. This does not account for the technical potential in charging appliances in the Norwegian distribution network (Statistisk Sentralbyrå, 2017).

Even though the electricity systems in Norway and Sweden are slightly different, both countries possess long-term storage and flexibility solutions in hydropower generation, and have integrated electricity markets through Nord Pool. Comparing technical potential between the two countries is thus a feasible approach. In 2016, The Swedish Energy Market Inspectorate (EI) conducted an extensive study of the technical potential of end-user flexibility in Sweden. The technical potential in Sweden was estimated to almost 8000 MW in the winter months with 5500 MW of this potential being supplied by residential end-users. In the summer months, the estimated flexibility was 3700 MW, with 1700 MW being supplied by residential end-users.

An earlier Swedish project, Elforsk, studied the possibility of curtailing electric heating and water heater loads. An average controllable load of 4-5 kW per house at 10-15 degrees below zero implied a technical potential of approximately 1500 MW in Sweden (Elforsk, 2006).

Gaia Consulting (2011) estimated the practical potential for end-user flexibility in the Nordic region. The research highlighted that most of the flexibility potential is in Swedish and Norwegian households, with some flexibility available in Finnish households and a very limited flexibility potential in Danish households. The results relied heavily on economical, technical and practical assumptions, but estimated the end-user flexibility potential in the Nordic region to between 4000 MW and 7000 MW, excluding flexibility from the industry. From this potential flexibility, between 1000 MW and 3500 MW originated from Norwegian end-users.

In summary, several attempts of quantifying the technical potential of end-user flexibility has been conducted, both in Norway and abroad. However, it is not clear from these research projects if this potential results from explicit- or implicit end-user flexibility. In a report from 2016, COWI Belgium highlighted that roughly 92% of potential peak reductions induced by end-user flexibility deployment would come from explicit end-user flexibility. The remaining 8% would come from price based programs and implicit end-user flexibility.

3.2.5 End-User Flexibility Deployment and Electrical Vehicles

The distribution network is tasked with several challenges due to a growing fleet of EV´s. Simultaneous charging of EV´s may result in thermal overloads, voltage deviations and even blackouts (Clement-Nyns, Haesen & Driesen, 2009). Several research projects study the effect of how EV´s can increase the flexibility of the distribution network by curtailing their time of charging.

Habib, Kamran & Rashid (2015) highlight the use of EV batteries to supply flexibility to the electrical network, and denote this Vehicle to Grid (V2G). Their research proposes that V2G applications improve reliability, efficiency and stability in the distribution network. However, they highlight that the economic benefits of V2G technology is reliant on the strategies of charging and aggregation.

Teng et al., (2015) conclude that with smart charging technology, 70 to 100% of EV charging demand can be shifted away from peak hours. Their research suggests that charging can typically be delayed by several hours when shifted away from peak load times and towards the night hours.

Sbordone et al., (2014) analyze how the installation of a prototype-charging system including separate battery banks and DER units may lead to a reduction in network reinforcements. The prototype system delivered feasible results in peak shaving implementation when compared to the main distribution network, and exhibited nearly zero impact on the infrastructure.

3.2.6 Dynamic Pricing, Tariffs and End-User Flexibility

Faruqui & Sergici (2010) review 15 different Demand Response pilots in the U.S, Canada, Australia and France. All pilots target peak demand reductions through dynamic electricity pricing. The review conclude that ToU-rates induce a peak demand reduction of 3 to 6%, while CPP-tariffing induce a peak demand reduction of 13 to 20%. Faruqui and Sergici highlight that by accounting for enabling technologies, the CPP-tariffing leads to a peak demand reduction of 27 to 44% due to different compensation mechanisms.

Bartusch et al., (2011) analyze how end-users respond to a demand based ToU-tariff. By utilizing this indirect control contract, a Swedish DSO wanted to investigate how they could reduce peak load in their distribution network. The study concludes that end-users respond positively to being charged according to this type of tariff. Furthermore, the introduction of the tariff decreased the peak demand substantially.

In a later study, Bartusch et al., (2014) study the effect of a power tariff on electricity consumption in a residential area of Stockholm. The attitude to shift consumption were measured over a long period, where the researchers tested the attitude over six years. The research concluded that although the attitude to shift consumption from times of high demand of electricity to times of low demand of electricity were significant, it was not reflected through an actual shift in consumption over time.

Haring & Andersson (2014) highlight the need for incentive based rewarding contracts when pursuing direct control flexibility mechanisms. Efficient contracts between the prosumer and central agent must be individually rational and incentive compatible. To make contracts individually rational, the end-user must be rewarded and not make a loss from entering the flexibility contract. Incentive compatibility occurs when the end-user receives incentives to display and share their actual flexibility costs. By introducing a non-linear framework of pricing, capacity reservation and deployment of reserve energy are being rewarded separately.

Another viable business model is proposed by Campaigne and Oren (2016). By utilizing a fuse control paradigm, flexibility aggregators impose capacity constraints on prosumers or penalize them for breaching a capacity threshold. Subsequently, the prosumers allocate the available electricity to separate devices. The contract between the flexibility aggregator and the prosumer is seasonal, and typically allow the aggregator to curtail consumption over time given a certain probability of curtailment.

3.2.7 Aggregation of Flexibility Volumes

To offer flexibility volumes from end-users efficiently to the market, pooling and aggregation of flexibility volumes is required. A much-discussed proposition is to introduce a participant often denoted as an *aggregator*. Although the definite role of the aggregator is yet to be decided both nationally and elsewhere in Europe, numerous models and designs have been discussed in recent literature and research. We discuss *integrated aggregators*, *independent aggregators* and *regulated aggregators*.

According to NordREG (2016), *integrated aggregators* are the desired option in Norway. This is due to regulations requiring the aggregator to assume balance responsibility in order to profit from any contracted reserve or activation of end-user flexibility. The aggregator can either assume the role as electricity provider and Balance Responsible Party (BRP), or the electricity provider and BRP can assume the role as an aggregator. ENFO (2016) highlights that the former solution is heavily reliant on well-defined and liquid flexibility markets. ENFO propose that the latter solution, will result in a more specific, flexibility oriented electricity provider and BRP.

The *independent aggregator* model is promoted in the European Commission. USEF (2017) propose a framework where a third-party assumes the role as an independent aggregator. NordREG (2016) highlights three ways of organizing the independent aggregator role. The first way relies on an independent aggregator with shared balance responsibility and no imbalance settlements when flexibility is activated. This model utilizes several BRPs per access point, and would not be possible to implement in Nordic countries. The second way is that the independent aggregator assumes shared balance responsibility and includes imbalance settlements and revenue reimbursements when flexibility is activated. By transferring any net profit from activating flexibility from the electricity provider to the independent aggregator, this model distributes the risk and return more neutrally between the electricity provider and the aggregator. The third way is based on the aggregator assuming no balance responsibility. By allowing no balance responsibility, the aggregator will reap the profit while the electricity provider assumes the risk of balancing and delivering electricity. SEDC (2015) highlights that this model is heavily dependent on future regulation- and policy development.

ENFO (2016) propose that a *regulated aggregator* model can be introduced by handing the aggregator role to either DSOs or the TSOs. When a DSO assumes the regulated aggregator role, the end-user can provide available flexibility and receive a reduction in their network tariff in turn. This model has been touted a viable option in countries looking to base their tariff regime on Time of Use (ToU). Alternatively, the DSO can source the aggregated flexibility through a direct contract. In this case, security of flexibility supply has to be accounted for in the same way as security of electricity supply. NordREG (2016) also proposes that the system operator and TSO can assume the aggregator role in a regulated model. In this model, the aggregated flexibility is serviced externally, but the system operator interacts directly with the end-user. This model emphasizes security of electricity supply and is a stark contrast to the many market based, independent aggregator models proposed by the European Commission in the Third Package and the Winter Package (2016).

3.2.8 Trading End-User Flexibility in Flexibility Markets

Eid et al. (2016) discuss a flexibility market design inspired by the French trading system and markets for flexibility in both the short-, medium- and long-term trading periods. In the French trading system, minimum bid capacities for balancing services have been reduced from 50 MW to 10 MW to motivate smaller parties like independent aggregators to participate in the balancing markets. The research is based on five markets; ancillary services, system balancing and network congestion management, spot markets and generation capacity markets.

Zhang et al. (2014) introduces a clearinghouse concept for flexibility called FLECH at the distribution level. The FLECH market utilizes aggregator-based offers to promote small scale DERs with up to 5MW for their active market participation. In this market design, the compensation is stipulated by the capacity needs of the DSO. The aggregator then responds to this capacity need by bidding prices and quantities of flexibility, and the FLECH market runs single-side auctions or super market trading where the aggregator designs specific flexibility products that are presented to the end-users.

A third, bid-less flexibility market design is presented by Gantenbein et al (2012). By updating and publishing prices in five-minute intervals, customers can respond to this price continuously by shifting their load (Larsen, et al., 2015).

ENFO (2016) discuss a “traffic light regulation” of monopoly and market functions in the electricity system, which was first proposed by Eurelectric (2014) in their report “Active Distribution System Management”. This system is based on the need for specific option schemes for Norwegian DSO´s. Separating monopoly- and market activities makes it possible to introduce new products that enables the end-user to participate in the market.

3.3 Project and Pilot Review - Norway

To supplement academic research and reports, we review current projects and demos involving end-user flexibility in Norway. Most of the relevant research projects on end-user flexibility is conducted by members of the Norwegian Smart Grid Centre. Some of these projects are in a start phase, while others have been running for several years.

3.3.1 EMPOWER (2015 to 2018)

Local Electricity Retail Markets for Prosumer Smart Grid Power Services (EMPOWER) is a project addressing the local energy and flexibility markets of the future. Among the participants is Universität St.Gallen, NewEn Projects GmbH, Schneider Electric Norway, eSmart Systems and Smart Innovation Norway. The project received funding from the European Union´s Horizon 2020 research and innovation program. EMPOWER is enabling consumers to become prosumers, encouraging the active participation of end-user´s consuming and producing energy in the electricity system. The end-goal is to develop a fully functional energy market in Europe where consumers can trade local energy while offering flexibility services to free up capacity from the regional and distribution network. The flexibility in the EMPOWER has multiple purposes. It handles imbalances and problems in the local micro grid, but also enables the prosumers to trade energy with wholesale markets. To enable end-user flexibility in the future, EMPOWER covers topics such as building site methods for data collection and acquisition and analyzes the impact of both single and multiple, organized prosumers on the energy system. The end goal is a local market place where flexibility is created and exploited for the benefit of both the DSO and the end-user (EMPOWER, 2017)

3.3.2 Smart Energy Hvaler (2012 to 2015)

Smart Energy Hvaler was a pilot included in the project Demonstration and Verification of Intelligent Distribution Networks (DeVID). The project implemented Smart Grid solutions in 25 households on the small peninsula of Hvaler between 2012 and 2015. The project proposed and analyzed methods for utilizing end-user flexibility. Smart Energy Hvaler focused on the response to price signals, dynamic tariffs and visualized consumption. Each participating household were equipped with a tablet displaying consumption in real time and introduced to a subscribed power tariff. Through the winter of 2013 and 2014, end-users reduced their net electricity consumption by 15% after correcting for temperature effects. Furthermore, a key finding in the project was the fact that end-users reduced both their power output and overall energy consumption. This resulted in 85% of all end-users documenting electricity cost savings (THEMA Consulting, 2014)

3.3.3 Demo Steinkjer (2011 to 2017)

Demo Steinkjer utilized the same infrastructure as Smart Energy Hvaler to conduct research on full-scale deployment of end-user flexibility in the distribution network. For NTE, Demo Steinkjer was an active arena for developing and testing out new energy solutions and trends such as demand-response mechanisms, end-user flexibility, design of tariffs and consumer behavior. NTE prioritized research on network rental models such as the subscribed power tariff and dynamic micro grids. By implementing a subscribed power tariff similar to the one in *Smart Energy Hvaler*, end-users reduced their net energy consumption by 5.3% during the first 6 months of the pilot. This reduction in consumption were not a result of shifted loads, but rather a permanent reduction in consumption due to the new tariff (THEMA Consulting, 2014).

3.3.4 ChargeFlex (2015 to 2017)

ChargeFlex is a R&D project that aims to solve the increased stress simultaneous charging of EV´s puts on the distribution network. The project explores how flexibility can increase network capacity by up to 25%, and how Demand Response, flexibility and EV´s can add value for network owners in the future. A key concept in ChargeFlex is to develop predictive models for EV charging, load management and available end-user flexibility. By utilizing these predictive models, an optimization model for load shifting will be made. This model will be used to activate flexibility immediately when required. The end-user can influence the flexibility offered to the system by setting a desired time for full charging of their EV. Key partners in the project include NTNU, eSmart Systems, Smart Innovation Norway, Fortum Charge & Drive, SFE Nett and Norgesnett (THEMA Consulting, 2014).

3.4 Project and Pilot Review – Abroad

In this part, we review relevant projects and pilots outside of Norway. Although these projects are influenced by different market schemes and regulations, they highlight the technical and economic efficiency of end-user flexibility in the distribution network.

3.4.1 INVADE (Various Countries)

The goal of the INVADE project is to integrate EV´s and increase the use of DS and batteries in the distribution network by designing a flexible energy management system. Like EMPOWER, INVADE is funded by the Horizon 2020 program, and is one of the largest R&D projects in Smart Grids and storage ever in the EU. The project has a budget of €16 million, and pilot sites are situated in Norway, Spain, Germany, the Netherlands and Bulgaria. Partners in the project include NTNU, Schneider Electric Norway, Lyse Elnett, GreenFlex BV, NewEn GMBH and eSmart Systems. The project has a broad mandate by focusing on the integration of DER and DS, coping with network limitations, handling uncertainty and increasing flexibility in a microgrid. This is mainly due to its focus on establishing a flexible infrastructure compatible with new, inexpensive technologies in energy production (INVADE, 2017).

3.4.2 Flexible Households (Sweden)

During March and April 2017, the Swedish TSO Svenska Kraftnät performed a pilot project together with Fortum Sweden. The scope of the pilot project was to investigate how 100 Swedish end-users could contribute through flexible consumption. The flexibility was utilized as a reserve to balance the system under normal operations. This kind of flexibility reserve is denoted FCR-N. By utilizing the flexible capacity in hot water boilers, aggregated flexibility delivered from 100 end-users amounted to 0.1 MW, which is the minimal required bid size of FCR-N. The pilot project concluded that the hot water boilers responded well to the flexibility needs, and that flexibility from the end-user was activated quick enough to satisfy the flexibility need. However, changes in metering and ICT-systems were highlighted as areas of improvement to make the flexibility reserves even more efficient (Svenska Kraftnät, 2017).

3.4.3 USEF (Netherlands)

The Universal Smart Energy Framework (USEF) was launched in November 2015 and gives clear design outlines for a common, European flexibility market. USEF is one of the few projects on the European continent that has tested integrated flexibility markets with a third-party aggregator. By doing this, flexibility can be traded like a commodity. Key partners in the USEF were large, household names in the European energy industry such as ABB, Alliander, DNV GL, RWE and IBM. At the Dutch pilot site Heerhugowaard, the USEF was put to test by involving 203 residential end-users. By installing smart meters in the household, the project proved that the flexibility framework was able to handle serious load congestions, created value for the end-user, DSO and BRP as well as successfully implementing an independent aggregator to sell and deliver flexibility (USEF, 2017).

3.4.4 GRID4EU (France)

GRID4EU was completed in 2016, and had a budget of €54 million. The project is one of the largest Smart Grid and demand response projects ever conducted in Europe. By including 6 large DSO´s, the GRID4EU project covered more than 50% of all European electricity customers. In 2014 and 2015, the contributing French DSO in the project ERDF conducted a study on demand response and peak shaving involving 217 households. By offering vouchers for consumption reductions between 6pm and 8pm on certain peak demand days, the project proved that end-users would adapt to this price reduction and reduce their consumption with 21% in this time slot on the specified days (GRID4EU, 2017).

3.4.5 LINEAR (Belgium)

LINEAR (Large-scale Implementation of Smart Grid Technologies in Distribution Networks) was a large-scale demand response project located in the region of Flanders in Belgium. By including 239 households and testing the influence of smart appliances on electricity consumption, the resulting analysis showed that an average maximum increase of 430W per household could be realized at midnight, and a maximum decrease of 65W per household could be realized in the evening. This potential end-user flexibility could be used to determine the impact of similar Demand Response programs including residential end-users. (D'Hulst, et al., 2015).

4. Regulations, Legislations and Policies

The following chapter discusses the regulatory framework that affect Norwegian network operators and end-users. The buildup of the regulatory model and how it affects investment decisions, is explained in detail. The main focus will be on Norwegian regulations, but we begin by describing the current and predicted regulation in the European Union (EU), which affects the Norwegian regulation.

4.1 European Union

The EU have a complex regulation of the European energy system, consisting of several directives, legislations and proposals. Despite not being a member of the EU, Norway is strongly affected by the shape of the regulation due to the European Economic Area (EEA) membership and interconnectedness of the European electricity system.

4.1.1 The Third Energy Package

The latest regulatory contribution to the European energy market is commonly known as the Third Energy Package. It was adopted by the European Commission (EC) in 2009 (European Parliament, 2017).

The legislation embraces five main areas; unbundling, independent regulators, Agency for Cooperation of Energy Regulators[4] (ACER), cross-border cooperation, and open and fair retail markets (European Commission, 2017a). Unbundling is the separation of electricity generation and supply from the operation of transmission networks. The main goal of unbundling is to increase competition and reduce consumer prices. To ensure a competitive European energy market, the European Commission stresses the need for industry- and government independent regulators. ACER is an agency established to promote cross-border cooperation between regulators and to strengthen the internal energy market. The European Network of Transmission System Operators for Electricity[5] (ENTSO-E) is established to

[4] http://www.acer.europa.eu/en/Pages/default.aspx

[5] https://www.entsoe.eu/Pages/default.aspx

ensure optimal network management across borders. The final focus area of the Third Energy Package is open and fair retail markets, with explicit focus on the role of end-users, market pricing, non-discrimination and transparency in future energy markets.

4.1.2 The Winter Package

Even though the Third Energy Package is the latest adopted energy legislation, there is a more recent proposal currently being overlooked by Member States and other European nations. Clean Energy for All Europeans, more commonly known as The Winter Package, is the latest contribution on changes to the European energy market, from the EC. The package is a compilation of proposals published by the EC on the 30th of November 2016 (Losch & Van Driessche, 2016).

There are eight proposals; proposal for a recast of the Internal Electricity Market Directive (1), proposal for a recast of the Internal Electricity Market Regulation (2), proposal for a recast of the ACER Regulation (3), proposal for a Regulation on Risk-Preparedness in the Electricity Sector and Repealing the Security of Supply Directive (4), proposal for a recast of the Renewable Energy Directive (5), proposal for a revised Energy Efficiency Directive (6), proposal for a revised Energy Performance of Buildings Directive (7), and finally, proposal for a Regulation on the Governance of the Energy Union (8) (Losch & Van Driessche, 2016). The proposals aim to transit EU to a clean energy economy and enlighten the need to re-design and change operational aspects of the existing electricity market. The main scope of the package is to implement actions necessary to reach the climate goals set by the EU in the Paris Agreement[6].

The package can be divided into three categories; proposals amending existing legislations in the energy market, proposals amending existing legislations on climate change, and proposals for new measures. The most relevant proposals for Norwegian DSOs, electricity markets and end-user flexibility are proposal (1) and (2).

The first proposal discusses a new market design, and the roles of participants (European Commission, 2017b). The proposition seeks to better adapt to the future electricity market, fueled by more variable and decentralized production, increased cooperation and transparency

[6] http://unfccc.int/paris_agreement/items/9485.php

for cross border transmission and trading. The proposal also highlights the need to incentivize active end-user participation in electricity markets.

Consumers should be allowed to enter contracts and agreements with aggregators and providers of flexibility measures without having to seek permission from suppliers or operators. Prosumers are encouraged to participate directly, or through aggregators, in wholesale and flexibility markets. The aggregators should be treated in a non-discriminatory manner based on their technical capabilities, and will not be required to pay compensations to suppliers or generators. The installation of AMI increases competitiveness for businesses and allow for more active end-users to help control their electricity costs (European Union, 2012). The legislative proposals discuss smart metering data. Each country must define which parties that have access to consumption data and metering.

The first proposal also highlights the role of the DSO. The proposal aims to clarify the role of DSOs in providing network services suitable for flexibility, storage and recharging points for EV's. The DSOs are incentivized to improve their system for better utilization of flexible end-users. This includes increased distributed generation, demand-side response programs, local storage solutions and energy efficiency initiatives. The proposal states that DSOs should be compensated accordingly, and must specify standardized market products for their services. Although DSOs are encouraged to embrace technologies such as storage, end-user flexibility and EV charging, they are expected not to provide these services. For example, DSOs should facilitate EV charging infrastructure, but can only own, develop, manage or operate charging points if regulators allow them to. Regulators can only allow the former if no other third party expresses an interest in taking on this responsibility.

The second proposal discusses the different regulatory measures set to improve the internal market for electricity (European Commission, 2017c). The importance of dynamic pricing of electricity, and how trading in the wholesale markets prevents introduction of capping of wholesale prices is highlighted. By implementing correct pricing mechanisms, the Commission aims to increase investment interest in new generation, capacity and end-user flexibility.

Rules on balancing markets for energy and capacity are introduced, including the need for free access to all participants individually or by aggregation. This will enable end-user flexibility and storage as alternative balancing mechanisms. Market participants should also be responsible for any imbalance they cause.

As an additional part of the Winter Package, the Commission also released a report on capacity mechanisms, known as Final Report of the Sector Inquiry on Capacity Mechanisms (European Commission, 2016). This report is not one of the eight proposals, but is interesting to discuss in terms of end-user flexibility. The European Parliamentary Research Service define Capacity mechanisms as *administrative measures to ensure the achievement of the desired level of security of supply by remunerating generators for the availability of resources* (Erbach, 2017).

In addition to intermittency challenges from renewable electricity generation, many countries experience critically low investment rates in generation to meet peak demand. There are not only challenges on the supply side of the electricity market, higher loads from more power demanding devices must be balanced out by operators. Capacity mechanisms are common tools to meet these challenges, but are costly and not fully utilized in normal operations.

To handle the challenges associated with capacity mechanisms, the Commission appeals for an assessment of all new capacity mechanisms before establishment. One criteria states that the objective of the measure must be of common interest, meaning that it must sort out a long- or short-term generation adequacy problem. Existing measures will generally support short-term adequacy, whilst long-term adequacies will generally appeal for new investment. End-user flexibility is a possible measure to resolve short-term adequacy related to certain hours, a day or even a month. However, the Commission stress that any payments for flexibility must not turn into subsidies for energy-intensive consumers. Capacity mechanism should be open to all capacity providers, both domestic and foreign, and especially new entrants.

4.2 Norwegian Regulations and Legislations

4.2.1 Natural Monopoly

It would not be optimal for society to have competition on electricity distribution and transmission, contrary to economic the benefits of having competition between electricity retailers. Competition amongst DSOs would lead to overinvestments in the network systems. Due to this aspect, electricity networks at all levels in Norway are natural monopolies. The monopolistic situation results in network operators being subject to strict governmental regulations. The Norwegian Water Resource and Energy Directorate[7] (NVE) is the national regulatory authority in Norway, and is a directorate governed by the Norwegian Ministry of Petroleum and Energy[8]. Policy instruments are used to ensure socially efficient operation, high levels of utilization and development of the network. The regulations are divided into direct and economic revenue regulations, and compliance monitoring. Direct regulations set a framework for operations and definition of roles, whilst compliance monitoring ensures operators abides regulations. The regulations on economic revenue make sure that operators provide a stable and secure service in a socially efficient way. In Norway, all DSOs and the TSO are regulated by NVE (NVE, 2017d).

4.2.2 Revenue regulation

To promote efficient energy markets and cost-effective energy systems, a revenue cap regulation was introduced by NVE in 1997. The revenue cap regulation is part of the regulation on economic and technical reporting, revenue cap for network operators and tariffs (Olje- og Energidepartementet, 2017). It determines what income a company can expect and how they should adjust their network tariffs accordingly. The revenue cap covers the network operator's costs and give a reasonable return on assets under the assumption of efficient operation, reasonable maintenance and network development. When calculating a company's cost-efficiency, the regulatory uses a benchmarking method known as Data Envelopment Analysis (DEA) (NVE, 2017e).

Bogetoft and Otto (2011) define benchmarking as the *relative performance of evaluations and the systematic comparison of production entities.* A general explanation of the theory behind the DEA is included in the next sections, before focusing on how DEA is applied to Norwegian network operators.

[7] www.nve.no

[8] https://www.regjeringen.no/en/dep/oed/id750/

4.2.3 Data Envelopment Analysis

Data Envelope Analysis (DEA) is defined as *a mathematical programming method for estimating best practice production frontiers and evaluating the relative efficiency of different entities* (Bogetoft & Otto, 2011). Every DEA begins by finding a feasible production area for the technology in the market. The area is found by using minimal extrapolation to locate the smallest production area that still includes all the data (Bogetoft & Otto, 2011).

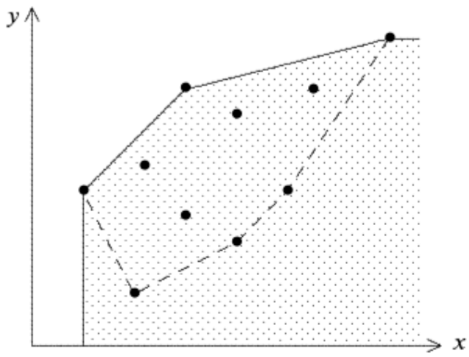

Figure 4-1: Possible Production Area (Bogetoft & Otto, 2011, p. 26)

The dots in figure 4-1 shows how much output, y, a company produce with input, x. The most efficient companies are located on the outer line as they produce the most output at their respective input. These companies establish the efficiency frontier, and are denoted *reference companies*. These companies are considered 100 percent efficient and the rest of the companies in the industry are measured against them. If the figure represents an entire industry, all companies will be located either on the frontier or in the dotted area below. It is important to separate productivity and efficiency. Productivity can be explained as a company’s absolute performance, whilst efficiency can be interpreted as the relative performance (Bjørndal, Bjørndal, & Fange, 2010). Bogetoft and Otto define efficiency as *actual performance divided by optimal performance* (Bogetoft & Otto, 2011).

The DEA measure technical efficiency by measuring the distance between a specific company and a reference company along the frontier.

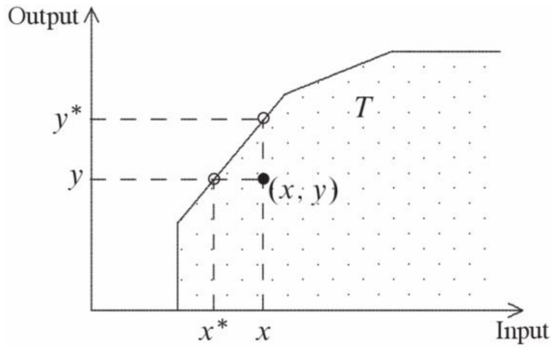

Figure 4-2: Technical Efficiency (Bogetoft & Otto, 2011, p. 27)

Technical efficiency is either input- or output driven. Input driven efficiency is the difference in use of input between the specific company, x, and that of a reference company, x*, at a given production volume (x,y). Output driven efficiency is defined as the amount produced by the specific company at a given amount of input, y, compared to that of a reference company, y* (Bogetoft & Otto, 2011).

There are some assumptions necessary for DEA. The first assumption is free disposability. This means that if a company can produce a given output at a given input, they can also produce similar, or a smaller, output with a higher input than originally. In figure 4-3 below we see that a company located in point 3 still lies within the allowed production area if it increases its input and/or reduce their output, resulting in point 2, 4 and 5 all being feasible. However, this would not be optimal as they provide a lower, or similar, output at a higher input (Bogetoft & Otto, 2010)

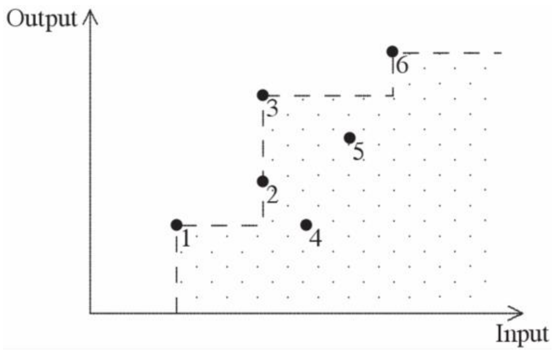

Figure 4-3: Free Disposability (Bogetoft & Otto, 2011, p. 12)

The second assumption is convexity. If two combinations of inputs and outputs are feasible, then any mixture of the two is also feasible. By combining inputs and outputs, the possible production area shown in figure 4-4 is obtained.

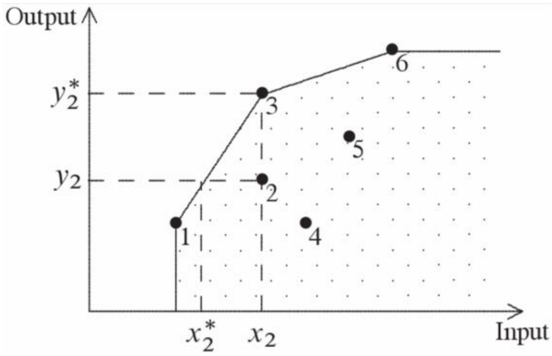

Figure 4-4: Free Disposability and Convexity (Bogetoft & Otto, 2011, p. 12)

A frontier represented by the full lines between the three reference companies, 1, 3 and 6 is shown in Figure 4-4. Production point 2 show that it is possible to produce the same output y_2 at a lower input x_2^*. Similarly, it is possible to produce a higher output y_2^* at the current input, x_2. The former reflects input efficiency, whilst the latter reflects output efficiency. The final assumption necessary is the option of scaling operations. This assumption is based on the reasonability that if a production plan is feasible, it is likely that one can produce somewhat fewer (more) outputs with somewhat fewer (more) inputs. Different assumptions can be made about the scalability options, but the two most common assumptions are constant returns to scale (CRS) and variable returns to scale (VRS). Both are displayed in the figures below.

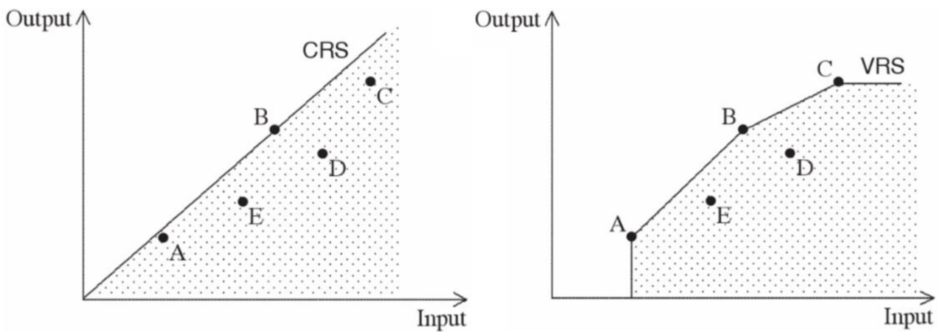

Figure 4-5: CRS & VRS (Bogetoft & Otto, 2011, p. 87)

In the case of CRS, an increase in input will generate a proportional increase in output. VRS assumes that the output will increase relatively less than the increase in input. Considering company B in figure 4-5, output increase proportionally with increased input in CRS. On the other hand, considering company B in figure 4-6, increasing input will cause a relatively smaller increase in output with VRS as opposed to CRS.

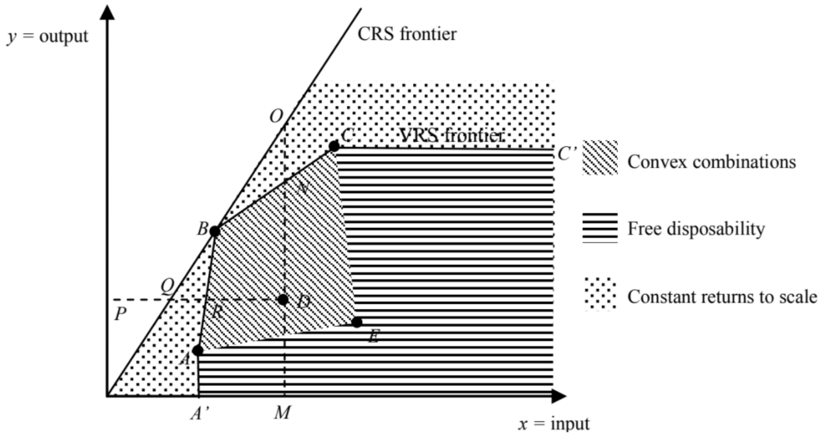

Figure 4-6: Technical Efficiency Under CRS and VRS (Bjørndal, et al. 2010, p. 324)

Figure 4-7 displays all assumptions in one figure. The combination of free disposability and convexity creates a VRS frontier, A'ABCC', where company A, B and C are reference companies. By evaluating company D and considering the VRS frontier to be correct, the company's data point is not located on the frontier. Figure 4-7 displays two common directions, vertical (output) and horizontal (input). Beginning with the output direction, the reference point for company D will be N. The output efficiency can be calculated as MD/MN. The higher this value is, the more efficient the company is. For input direction, the reference point for company D will be R. The input efficiency can then be calculated as PR/PD.

The assumption on scaling operations have an impact when calculating efficiency. When considering the CRS frontier instead of the VRS, the entire front is shifted upwards, except for in point B. By re-evaluating company D, the reference point in the output direction is now O, with output efficiency calculated as MO/MD. For the input direction, the new reference point is Q, with input efficiency calculated as PQ/PD. With CRS, output and input efficiency will be equal (Bogetoft & Otto, 2011). This highlights that CRS will give higher (lower), or equal, efficiency measures for output (input) compared to VRS.

4.2.4 The Regulatory Model for Norwegian DSOs

The Revenue Cap in Distribution Networks

The following sections will give an interpretation of the revenue cap model for distribution networks (NVE, 2017f). The revenue cap model for regional and transmission networks are similar, but differ in terms of complexity and output variables. Many network operators operate within both the distribution and regional network level, whilst only a few companies have costs on the transmission level.

The revenue cap for the forthcoming year is notified by NVE in November the year in advance, and network operators set their tariffs accordingly. All data, results and calculations are published to ensure transparency and understanding of the methodology. Only power prices, inflation, and the weighted average cost of capital (WACC) can cause deviation between notified and final Revenue cap for a year, these are merely estimated in the notification. Any cost errors or technical data discovered in hindsight are also corrected in the final edit. The Revenue cap is calculated based on actual total costs from two years back, adjusted for inflation, and a cost norm.

Mathematically, the Revenue cap model can be written as follows:

$$RC_t = (1 - \rho) \times C_t + \rho \times C_t^*$$

RC_t is the revenue cap for period t, C_t is the cost recovery based on the company's own costs, denoted the cost basis, whilst C_t^* is the cost norm calculated after the the DEA. ρ is a norm share with a value between 0 and 1. In Norway, ρ is equal to 0.6, resulting in the model giving a 40 percent cost recovery part based on the company's own costs, and 60 percent cost norm resulting from a benchmarking model. The size of ρ reflects the efficiency focus of the RC-model, and influence network operator's investment decisions. Increasing ρ will increase the weight of benchmarking in the model, and increase the focus on efficiency (Amundsveen & Kvile, 2015).

The formula for the cost basis can be written as follows:

$$C_t = (OM_{t-2} + VoLL_{t-2}) \times \left(\frac{CPI_t}{CPI_{t-2}}\right) + NL_{t-2} \times P_t + Dep_{t-2} + RAB_{t-2} \times r_{NVE}$$

Where OM_{t-2} are operation and maintenance costs from two years back, $VoLL_{t-2}$ is the value of lost load for consumers from two years back, both the previous are adjusted for change in the consumer price index (CPI). NL_{t-2} is the transmission loss from two years back, multiplied with the reference price on power, P_t, measured as volume weighted average system price per MWh on the power exchange over the year. Dep_{t-2} are the yearly depreciations from two years back. This measure is included to increase investment incentives (Amundsveen & Kvile, 2015). RAB_{t-2} is the regulatory asset base from two years back, multiplied with the reference rate of NVE, r_{NVE}. The asset base is equal to the amount invested in network capital per the 31st of December the previous year, plus 1 percent working capital. The mathematical calculation for the reference rate can be found in the appendix.

Calculation of the Cost Norm

The final factor in the Revenue Cap Model is the cost norm C_t^*, which requires a more thorough explanation than the previous fractions due to its complexity. The cost norm is calculated in three steps: the DEA, a regression analysis to consider geographical differences and a final calibration. The DEA-model used by NVE is an input oriented model with a CRS assumption (Bjørndal et al., 2010). By identifying the most efficient companies, the DEA finds the companies that provide services using the least amount of resources. These companies form the efficiency frontier, and are denoted as reference companies. In the current model for distribution networks, the resources are represented by costs. Previously, the model hade multiple input variables which have later been removed. The tasks are represented by output variables on kilometers of high voltage power lines, number of customers and number of network stations. The outputs in the model differ between the regional and distributional network level, both in terms of variables and weighting measures. For example, a capacity increase at a network station in the model for regional networks will increase the output related to number of network stations. A similar increase in capacity in the distributional network model will not increase the output, because the model for distribution networks only counts the number of stations (NVE, 2015a).

By using one or more reference companies, a virtual company with measurements equal to a weighted average of comparable reference companies, is generated. This virtual company's cost will be a weighted average of the costs of one, or several, of the most comparable reference companies, and represents the cost level that specific company will have to acquire to be denoted as fully efficient (100 percent) in fulfilling their specific tasks. The cost basis of a company is compared to the input of all network operators in the distribution network. The input is equal to the average costs over the last four years. Then, the reference companies most comparable to the specific company is found. For example, for a company in 2017 their cost basis will be based on costs from 2015, and these will be compared to the average costs of one or more of the reference companies in the period between 2011 and 2015.

To simplify the explanation of the DEA-model used by NVE, two network operators are selected for exemplification. The network operators chosen are Agder Energi Nett AS and Stryn Energi AS. The DEA-data is extracted from the regulatory model tool *Adaptiv* provided by Adapt Consulting (Adapt Consulting AS, 2017). The results will be explained and presented in the tables below. The example will continue throughout the stepwise explanation of the DEA. All numbers are inn 1,000 NOK.

	Agder Energi Nett AS	Stryn Energi AS
Cost basis	832 712	39 025
Number of subscribers	194 426	4 681
Km of HV-lines	5 824	274
Number of network stations	8 066	354

Table 4-1: Input and output variables for Agder Energi Nett AS and Stryn Energi AS

Table 4-1 show the input- and output variables of the two companies. We immediately see that the two companies differ in size, both reflected in the cost basis and the magnitude of the output variables.

	Agder Energi Nett AS	Stryn Energi AS
AS Eidefoss	19.47%	45.57%
Nord-Salten Kraft AS	0 %	0 %
Trøgstad Elverk AS	18.91%	45.21%
Hafslund Nett AS	61.63%	9.22%
DEA-result after step 1	87.32%	60.88%

Table 4-2: Weighted comparison to reference companies for Agder Energi Nett AS and Stryn Energi AS

Table 4-2 shows the first step of the DEA, where a virtual company is generated for the chosen company, based on a weighted comparison with the reference companies. The DEA-result after step one is not the result of the shares above, but the efficiency of the respective company after the first step of the DEA. The virtual company of Agder Energi AS is a weighted average of 19.47 % of AS Eidefoss, 18.91 % of Trøgstad Elverk AS, and 61.63 % of Hafslund Nett AS. Similarly, the virtual company of Stryn Energi AS is a weighted average of 45.57 % of AS Eidefoss, 45.21 % of Trøgstad Elverk AS, and 9.22 % of Hafslund Nett AS. Note that none of the example companies have Trøgstad Elverk AS as a reference company.

In the second step, the results of the DEA are adjusted for differences in their operational framework, to provide a more just comparison of the companies. The results are therefore adjusted for differences in topography, climate and network structures using regression analyses. When comparing companies, it is important to differ between exogenous and endogenous variables. Exogenous variables are variables that lie outside the company's control, whilst the endogenous variables are related to choices on technology (investments) and organizational factors (operation). The exogenous variables in the second step of the DEA in distribution networks are (Amundsveen & Kvile, 2015):

- Share of ground cables
- Share of power lines in dense forest
- Mountain - steepness, small scale power generation and share of airborne cables in broad-leaved trees
- Wind-coastal - wind conditions, distance to mainland, number of islands and share of undersea cables
- Frost - snow, winter darkness, icing and temperature

	Agder Energi Nett AS	Stryn Energi AS
Share of ground cables	-6.43 %	-0.04 %
Share of power lines in dense forest	1.17 %	2.52 %
Mountain	4.46 %	11.98 %
Wind-Coastal	1.44 %	-0.02 %
Frost	0.53 %	-1.04 %
Adjustment step 2	1.18 %	13.41 %
DEA-result after step 2	88.50 %	74.29 %

Table 4-3: Adjustment in DEA-result for difference in framework for Agder Energi Nett AS and Stryn Energi AS

Table 4-3 shows how the different framework-variables impact the DEA-result for the two companies. Negative numbers will indicate that the company operate in easier conditions than the virtual company generated in step 1, whilst positive numbers indicate the contrary. For example, we see that both network operators have a reduction in their results from having a smaller share of underground cables, but also an increase from having a larger share of airborne power lines in dense forest than their virtual company has. Agder Energi Nett AS have a smaller number of islands and subsea cable and frost. For Stryn Energi AS we see that it have a significant increase in their DEA-result because they operate in steep landscape and have small-scale generation located within their area of operation. They also have an increase in efficiency due to share of power lines in dense forest. The three other variables cause a slight reduction in the efficiency. In total, both the companies have an increase in efficiency in the second step, because their surroundings are more demanding than for their respective virtual companies.

In the final and third step of the DEA, the calibrated DEA-result is calculated. At first, the cost norm is re-calculated, using the expected electricity price for the present year, the expected reference rate of NVE, depreciations and the basis for return on assets, excluding customer owned assets. The reasoning for calibrating the DEA-result from the second step is to ensure that age differences in assets are taken into consideration, and that the average network operator receive a reasonable return on assets. An additional value is added to companies according to the book value of their asset. The calibration is necessary to give network operators the incentives to invest in new assets. When investing in new assets, the operator's efficiency in step one of the DEA are reduced because of the investment cost. The third step of the DEA seeks to compensate for some of the negative effects on efficiency. In time, the effect of the investment will decrease because of the depreciation in asset value (Amundsveen & Kvile, 2015). By multiplying the company's cost basis with the results of its DEA after the second step, you find the company's DEA-norm. Adding up the DEA-norm for the entire industry and then subtracting the total cost basis for the industry, results in a gap between the two. In 2018, this gap was approximately 1.5 billion NOK (NVE, 2017g). The gap is to be added to the companies, and is distributed according to the company's regulatory asset base divided by the industries total regulatory asset base. The larger the gap is, the greater is the incentive to increase assets through investments. By adding this share to the DEA-norm from the second step, the calibrated cost norm (calibrated DEA-norm) is obtained. When dividing this calibrated cost norm with the cost basis for the company, we get the final DEA-result, often denoted as the calibrated DEA-result.

	Agder Energi Nett AS	Stryn Energi AS
Cost basis for step 3	771 144	37 315
DEA-norm	682 436	27 721
Share of the industry's base for return on assets	6.83 %	0.23 %
Addition to norm	107 171	3 649
Cost norm	789 607	31 371
DEA-result after step 3	102.39 %	84.07 %

Table 4-4: Calibration adjustment in DEA-result for Agder Energi Nett AS and Stryn Energi AS

Table 4-4 shows how both the companies get an addition to their DEA-result from step two. Agder Energi Nett AS gets a larger addition to its DEA-result as company has a larger share of the industry's total assets, approximately 6.83 %. By calibrating the DEA-result, the company's efficiency increases from 88.50 % to 102.39 %. The company is therefore considered more efficient than the average company in the industry. Stryn Energi AS is a relatively smaller company, which means it has a smaller share of the industry's total assets, approximately 0.23 %. The company's efficiency increases from 74.29 % to 84.07 %. The company is therefore considered less efficient than the average company in the industry.

Allowed Revenue

Finally, the parts above are merged into what is known as the allowed revenue for Norwegian network operators. Mathematically it can be written as follows:

$$AR_t = RC_t + CON_t + E_t - VoLL_t + (Dep_t - Dep_{t-2}) + (RAB_t - RAB_{t-2}) \times r_{NVE}$$

Here, CON_t is the costs in overlying network and E_t is the property tax. Both are added to the revenue cap. Note that the revenue cap (RC) in this equation includes the individual revenue caps from both the distribution, regional and transmission network. The value of lost load for consumers $VoLL_t$ is subtracted from the equation. This value of VoLL can also be read as the quality adjusted revenue cap of energy not supplied to consumers. The VoLL is included in the model to incentivize network operators to focus on asset maintenance, prevent power outages and invest efficiently. Consumers are divided into six groups; agriculture, households, industry, trade and services, public services and industry with electricity driven operation. Each group have a rate on cost per lost load at different timeframes. Lastly, changes in depreciation $(Dep_t - Dep_{t-2})$ and regulatory asset base $(RAB_t - RAB_{t-2})$ are added. The latter is multiplied with the reference rate of NVE, r_{NVE}. The changes in depreciation and regulatory asset base are included to remove time lag for investments due to the costs used for calculating the revenue cap being two years old (NVE, 2017d).

5. Investment Case, Skagerak Nett

This chapter includes a discussion of the economic effects of how end-user flexibility can be used to defer investments in capacity increasing components. The data and case will be presented individually. The case outline and costs are provided by Skagerak Nett[9], and are useful to highlight the economic effect of utilizing end-user flexibility. Certain assumptions and modifications are made to adjust the case to the scope of our thesis and to make it applicable to analysis in the context of the regulatory model for distribution networks.

5.1 Case Presentation

The data is derived from a regional network substation in the southern part of Norway. This circuit is connected to several distribution networks. We denote these *underlying distribution networks*. The regional network supplies approximately 6,000 end-users. About 85 percent are residential consumers, whilst the rest are a mix of commercial, industrial, agricultural and public-sector consumers.

The investment case looks at a reinvestment in two transformers to increase capacity at a transformer station. When malfunctions occur in a major component at a transformer station, network operators rely on sufficient reserve capacity as a backup. The backup must be constantly available. The reserves in the case are supplied either through the other transformer on the respective station, through reserves in the underlying networks, or through end-user flexibility. The first solution requires free capacity on the second transformer. The maximum load at the station is not the typical load. The station might be operating well below the maximum capacity at all days of the year, except one. If a malfunction occurs on a day of the year when the transformer operates at full capacity, it can result in outages if there are not substantial reserves in the network. It is important to note that one transformer can supply all consumers if the other malfunction, in most hours of the year. The use of end-user flexibility in case of malfunction is only desirable if a malfunction occurs at a day when load usage is high.

[9] http://www.skagerakenergi.no/eway/nett.html

The station considered in the case has historically operated at full capacity on several days during the year. The network operator can change connection to reserves in the underlying network. Both transformers are approximately 28 years old in 2017. The technical lifespan of the transformers is approximately 50 years. Because of increasing power usage in critical hours amongst consumers, the transformers must be upgraded to increase capacity before their technical lifespan is over. Changing a transformer early has a cost, as the full value of the transformer is not realized. The transformer is depreciated over 25 years. Which year this investment is undertaken traditionally depends on the predicted load increase. In the analysis, Skagerak Nett studied how utilizing end-user flexibility as a reserve can help defer investments. Using end-user flexibility in case of component malfunctions and peak hour management during normal operational periods are both discussed in the case.

5.2 Investment and End-User Flexibility Cases

The analysis discusses four cases, one traditional investment case and three cases with end-user flexibility. To increase the complexity of the analysis, we include two different scenarios where end-user flexibility is utilized, and two different flexibility volumes. Lastly, we include three load increase prediction levels. In this section, we present the cases, scenarios, flexibility volumes and load increase prediction before analyzing their desirability.

Case 1*:* Investing in capacity increase without utilizing end-user flexibility
Case 2*:* Compensating flexible end-users through discount in tariffs
Case 3*:* Compensating flexible end-users through an availability payment of 20.000 NOK per MWh and activation payment of 20.000 NOK per MWh
Case 4: Compensating flexible end-users through an activation payment of 30.000 NOK per MWh

In Case 1, capacity is increased by investing in two new transformers on the station. The investment is undertaken in the year when the N-1 criteria is no longer met, which in this case is 2019 (year 1). The investment ensures the capacity needed to handle peak loads and normal operations. This can be considered the traditional capacity increasing solution for a network operator today.

Case 2 to 4 utilize end-user flexibility to defer the investment in new transformers. In these cases, transformer capacity is primarily used to supply prioritized loads. Using end-user flexibility is acceptable to the network operator if disconnecting or curtailing flexible end-users guarantee supply of all non-flexible consumers in case of malfunction. The three flexibility cases differ in terms of compensation rates. The rates are tentative, but are set according to an estimate the network operator uses for cost of VoLL. The rough estimate used by the network operator is 50.000 NOK per MWh, and can be considered an opportunity cost. The cost of VoLL vary between consumer segments. Based on this estimate, the values for availability and activation are chosen as lower values. The costs amount to 20.000 NOK per MWh for availability and 20.000 NOK per MWh for activation in Case 2, and 30.000 NOK per MWh for activation in Case 3. It is worth noting that we denote payments in costs per MWh to reflect the set up in the investment case provided by Skagerak Nett. For example, a cost of 30,000 NOK per MWh is equal to 30 NOK per kWh. The magnitude of this payment can be argued as large, but is used as an average based on flexibility being provided from different segments, with different valuation of electricity. The magnitude of the compensation payments is an average for all end-users in this case, but is likely to differ between end-user segments in reality.

We introduce two different scenarios where end-user flexibility is utilized

Scenario 1: Ensure sufficient capacity in transformers to handle normal operations and peak loads. End-user flexibility is only utilized as a reserve in case of component malfunction on a transformer.

Scenario 2: Ensure sufficient capacity in transformers to handle normal operations. End-user flexibility is utilized to handle peak loads and as a reserve in case of component malfunction on a transformer.

Scenario 2 includes a more extensive application of end-user flexibility, whilst Scenario 1 requires capacity-increasing investments at an earlier stage to handle peaks in normal operations. Some of the prioritized loads in the two scenarios are also managed by redirecting currents and reserves in underlying networks.

Furthermore, the analysis considers three different load increase predictions (34, 16 and 0 percent) and two different flexibility volumes (F1 and F2). F1 includes consumers that are already flexible to the TSO. The existing flexible end-users are connected at both the regional and distribution network level. Existing flexibility therefore provide a feasible flexibility option at distribution network level. F2 also includes a tentative flexibility from households, in addition to the existing flexibility. The tentative household flexibility assumes that 33 percent of all households adjust their consumption by 1.5 kW in hour 8, 9, 10, 16 and 17 (peak hours), and 1 kW in other hours. When aggregated, household flexibility it provides 2.52 MW in peak hours and 1.68 MW in the other hours.

For Case 1, the flexibility volume is irrelevant. The investment in a new transformer will be undertaken in year 1 independently of the flexibility volume and LIPs. For the flexibility cases, Case 2 to 4, both LIPs and flexibility volumes affect when the investment is undertaken. In total, 42 alternatives are displayed. The following section will provide a general discussion of the different cases, scenarios and flexibility volumes, in addition to how these react to different LIPs.

5.3 Data

The calculation of loads in the case are based on estimated load in MWh for two transformers on the substation. Both transformers are situated at a station included in the regional network. The load values are historical data from 01.01.2010 to 31.12.2016. These values are used to predict the load imposed on the transformers under different load increase predictions. The load predictions are estimated yearly from 2018 to 2040. The total load increase predictions are calculated as the sum of estimated yearly increases. All load increase predictions are based on the electricity system statement of Skagerak Nett. The data obtained have previously been used by Skagerak Nett to perform an analysis of the present value (PV) of different investment alternatives and alternatives using end-user flexibility in the regional distribution network.

Consumption, flexibility and costs are assumed scalable at an equal rate. The analysis considers the cost of different alternatives of the cases relative to each other. All costs are downscaled equally to sustain comparability. Estimations done by Skagerak Nett on costs, load changes, compensation methods and malfunction probability are used to display economic effects at the distribution network level. There are some reserves in the underlying network. This allows the operator to use end-user flexibility as a reserve for a short period until they re-connect to the underlying network. This use-area is however not discussed further in the analysis.

An investment in a transformer with greater capacity will increase the output side of the DEA in the regulatory model for regional networks, since it has an additional weight rate for increased capacity. This is not the case in the regulatory model for distribution networks, which only take number of stations into account. When transferring the data and case to the distribution network level, this output effect is removed. The network operator would only have an increased output in the regulatory model for distribution networks by building a new network station. The changes therefore only occur on the input side (cost), and not on the output side (tasks).

5.4 Cost and Load Estimates

Skagerak Nett assume a maximum load increase prediction (LIP) of 34 percent until 2040. The assumed load profile is displayed in the figures below.

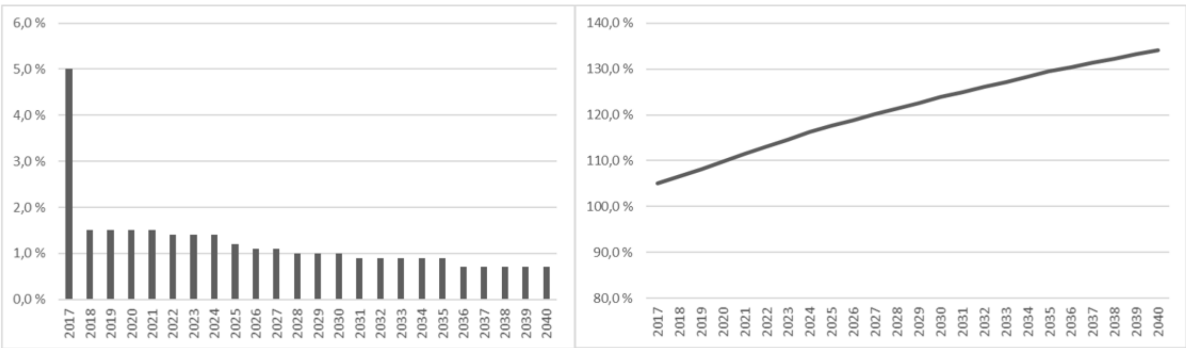

Figure 5-1: Annual and Accumulated Load Increase Prediction

After 2040, we assume a flat growth rate in load. For 16 percent LIP the figures will have the same shape and trend, but the values will be half of the above. For 0 percent LIP both curves will be flat. The different LIPs are based on expected load development in different areas. 34 percent LIP is an estimate for urban areas, and densely populated cities. 16 percent LIP is an estimate for semi-urban areas like villages. 0 Percent LIP is an estimate for rural areas like agriculture land. The large difference between annual load increase from 2017 to 2018 is caused by a new firm accessing the grid. Based on historical data, the operator reports approximately 1.3 failures in 100 transformers a year. This amounts to 1.3 percent probability of a transformer failure a year. The case looks at two transformers, and the failure in one is independent of a failure in the other. The probability of a failure in at least one of the two is therefore approximately 2.6 percent. It is assumed that all transformers can be overloaded by 5 percent without malfunctioning.

5.4.1 Choosing the Discount Rate

We use real values to calculate when calculating present values and changes in the revenue cap. To get more accurate results when calculating change in revenue cap and efficiency, nominal values and rates should be used. This is because the revenue cap is calculated using efficiency numbers from the DEA used by NVE, as we explained in section 4.5.2. The DEA uses capital costs based on the book values of both the respective operator, and the other operators in the industry. When using book values, the effect investments has on change in efficiency and in revenue cap is greater in the short term, than in the long term. The calibration in the third step account for the age differences, by adding the gap between cost norms and cost basis to network operators according to their regulatory asset base.

In our analysis, we use real values for estimating the effect different end-user flexibility cases has on the change in revenue cap an efficiency. One should ideally account for changes in book value for the entire industry as well as the operator, to get more accurate results. This is because the industry also reinvests and increase their book value. Because this affects the total value of assets for the industry, it also affects the efficiency calculation for each respective operator. The main scope of the thesis is however to discuss the relative effect of the different flexibility alternatives, not calculate the exact costs of different investment alternatives.

The discount rate used for calculating the PV and Net Present Value (NPV) in this chapter, and the following, is based on the reference rate calculated by NVE (NVE, 2017h). Because the values in the case are real values, we exclude the inflation from the reference rate. The predicted reference rate for 2018 is 5.88 percent including inflation. When removing inflation from the nominal rate, we get a real rate of 4.88 percent. Note that the RC-model tool uses the reference rate when calculating the revenue cap. When discounting the values, it is reasonable to use the expected rate of return, which in the long term should be equal to the reference rate.

5.4.2 Investment costs

The investment costs consist of the price of a new transformer, the cost of installing it, the cost of necessary changes on the station, and the cost of moving the previous transformer. The operator can report installation costs and changes as operation and maintenance costs. In this analysis, all costs related to the transformer is denoted as installation costs. In the original case from the regional network level, the current transformers on the station are two 25 MVA transformers with a price of approximately 4,5 million NOK each, including installation. Due to the expected load increase, the network operator will upgrade the transformers to two 40 MVA transformers when the load reaches the dimensioning criterion. Network operators dimension their network according to the N-1 criterion. The criterion ensures that operators always have reserves to supply priority load in case of a malfunction in a major component. Priority load is all load from non-flexible end-users and the load that flexible end-users denote non-flexible. The price of a new 40 MVA transformer is approximately 5,5 million NOK, including installation. Changing transformers also impose a relocation cost on the transformers that are moved. There is also an additional cost of approximately 400,000 NOK per transformer to prepare the station for two transformers with greater capacity. The technical life expectancy of a transformer is 50 years, and its value is depreciated over 25 years. The total cost of installing two new transformers amounts to approximately 11,8 million NOK.

In terms of downscaling the case to a distribution network level, the necessary capacity on the transformer decreases. To scale down the investment cost, the estimated price of 2,500,000 for a new 10 MVA transformer is used as a basis. Because the price is approximately half of the price for a 40 MVA transformer in the original case, we make the simplification of reducing all costs by 50% when downscaling the case from a regional to distribution network level. This includes reducing the costs by 50% for operation and maintenance, value of lost load and network loss. The transformers that are moved from the station is either stored, reused or discarded.

When the transformers are removed from the station, the remaining value of the transformer is calculated with a linear model. It is calculated as the age of the transformer subtracted from the total technical lifespan of a transformer (50 years), divided by the total technical lifespan. This share is multiplied with the purchase value and installation costs. Finally, the price for reinstalling the transformer at another station is subtracted. The calculation is multiplied with an assumed re-use rate of 2/3, estimated by the network operator. The re-use rate reflects the probability of reusing the old transformer when installing the new. This is a rough estimate, as some transformers are immediately reused, whilst others are stored or discarded. The total remaining value of the relocated transformer is subtracted from the total costs for the new investment. In situations where the investment can be postponed to the end of the case’s time horizon, the same calculation is done. However, in cases where the investment is deferred until the end of the technical lifespan of the current transformers, the original transformers are discarded. The cost of reinstalling the transformer then become irrelevant. It is assumed that the network operator does not have any additional costs related to aggregating flexibility volumes, hardware or software. It is assumed that these costs are assigned a third party that aggregates the flexibility volume and provide it to the network operator.

5.4.3 Operational costs

Costs related to operation and maintenance (O&M), network loss (NL) and costs of value of lost load (VoLL) will be discussed in detail below. A general description of the calculation of costs are given, but the magnitude of the costs will differ depending on the utilization of end-user flexibility, flexibility volumes and LIP.

The O&M costs from normal operations are calculated for all cases. For Case 2 to 4 utilizing end-user flexibility, an additional O&M cost for end-user flexibility is included. O&M costs also include costs of switching parts to sustain enough capacity and desired reserves in normal operations. These are considered maintenance costs, not investment costs. Expected reparation costs in case of malfunctions are also included in O&M costs. The cost is found by multiplying the probability of malfunctions with an estimated repair cost of 10,000 NOK. The expected costs of flexibility activation and availability are added to O&M, and are calculated by taking the average activation cost multiplied with the probability of having to activate end-user flexibility.

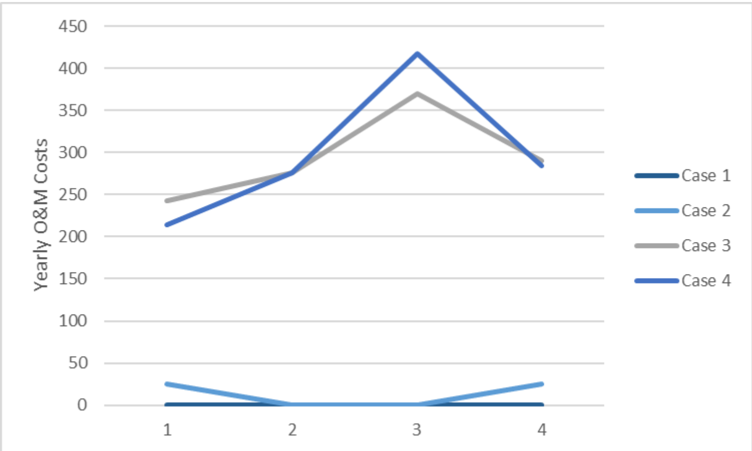

Figure 5-2: Change in O&M Costs Prior to Investment

Figure 5-2 displays the change in O&M costs in the first four years, for all cases in Scenario 2 with 34 percent LIP and F2 flexibility volume. After year four, the O&M costs for all flexibility cases drop after the network operator invests in new transformers. For Case 1, the costs for O&M are small because the investment is undertaken in the first year. For Case 2, the costs are also low, because the network operator does not pay directly for flexibility. For Case 3 and 4, the O&M costs are large, corresponding with the network operator paying for both availability and activation of flexible end-user. When the flexibility volume available is lower, the curves for Case 3 and Case 4 lie closer to the x-axis. Similarly, if the network operator use flexibility less extensively, as in Scenario 1.

Calculating the value of lost load is complex. The first step is to calculate the number of hours without reserves before and after activating flexibility. In the original analysis from the regional network, this calculation is the number of hours before connection to underlying networks. The probability of load curtailment is then calculated. These calculations are based on historical data and predictions from Skagerak Nett. The average MWh in hours without reserves is calculated for each year, and reflects the VoLL costs that occur if the malfunction happens in a critical period. A critical period is when there are not enough reserves on the transformers and the operator needs time to activate reserves or end-user flexibility. The average MWh is then multiplied with the VoLL cost per MWh, estimated to 50.000 NOK per MWh by the network operator. The cost of VoLL is relatively equal for the different flexibility cases under the two scenarios, and only vary slightly with flexibility volume. For the Case 1, the cost of VoLL are lower than for the flexibility cases.

The costs of network loss are based on the thermic loss from transmitting electricity. The longer the investment is deferred, the more substantial the network losses are. Costs related to network loss are therefore greater for the scenarios with 16 percent LIP, as the investment is deferred for a longer period. The network losses are also greater in the first scenario where use of end-user flexibility is limited to cases of malfunction. In this situation, the network operator handles peak loads in normal operation by switching capacity. This switching imposes greater network losses than using flexibility. The explanation for the increase in costs for network loss is an increase in thermic loss. When the load increases and end-user flexibility is activated, the operator redirect the priority load of some end-users from other transformer stations in the network, to ensure sufficiency capacity in normal operations. These stations are located further away from the end-users, increasing the distance electricity travels and therefore the thermic loss. When LIP is 0 percent the costs of network loss is zero, because it is unnecessary for the operator to redirect currents from other stations.

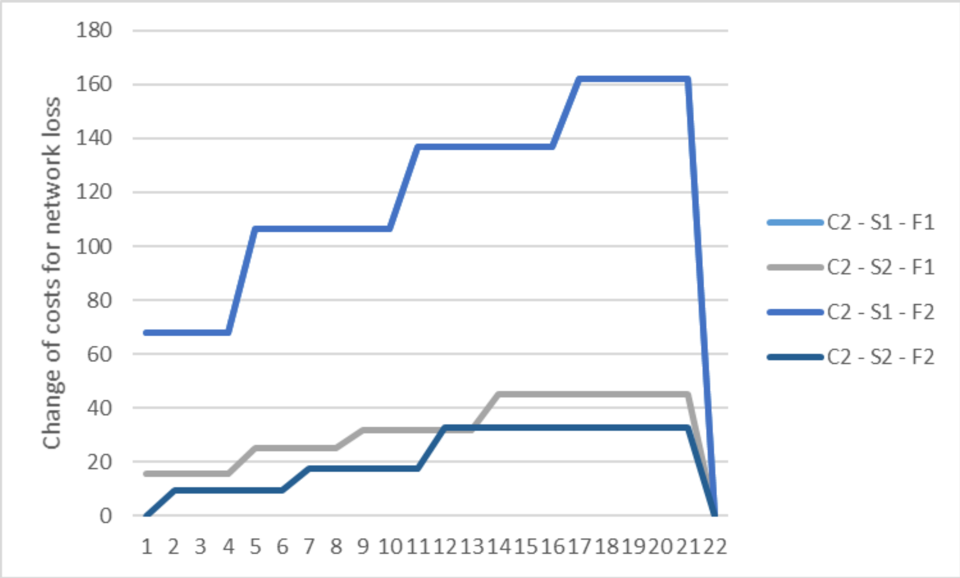

Figure 5-3: Cost of Network Loss in Case 2

Figure 5-3 displays the costs of network loss for Case 2 (C2) with 16 percent LIP, in the two Scenarios (S1 & S2) and with different flexibility volumes (F1 & F2). The costs for network loss increase with the yearly load increase, and drops when the investment is undertaken. The curves for Scenario 1 (S1) with F1 and F2 flexibility volume are overlapping. This is because the network operator must redirect more priority load when peak loads in normal operations are not managed by flexibility. The curves for Scenario 1 are therefore identical, because they are independent of the flexibility volume. For Scenario 2 (S2), the network operator must redirect more priority load if they have less flexibility available. The cost of network loss therefore decreases when households are included in the flexibility volume.

The compensation cost of end-user flexibility differs between the cases. In Case 2, the operator will not issue a direct payment. The compensation method is based on a tariff discount. Subsequently, this tariff will not be reflected as a direct payment in the value stream. The compensation to flexible end-users will be in the shape of lower network tariffs. For Case 3 where the operator pays for availability and activation, there will be an additional cost added to O&M. For the availability, they will pay a cost for flexibility calculated by multiplying the total available flexibility in MWh with the given availability cost. In our case, it is set to 20.000 NOK per MWh. The calculation of the activation is different for Scenario 1 and 2. For Scenario 1, the calculation looks at the cost of flexibility activation to function as a reserve in case of component malfunctions. This cost is based on the product of the probability for activation and the average activation cost in case of malfunction. For Scenario 2, the calculation for flexibility activation to handle peaks in normal operation is added to the cost of using end-user flexibility in case of malfunctions. The cost of using flexibility to manage peak loads in normal operations is calculated as the total lack of capacity (MWh) caused by peaks loads multiplied with the activation cost of 20.000 NOK per MWh. The probability for activation is in this case equal to the probability for malfunction.

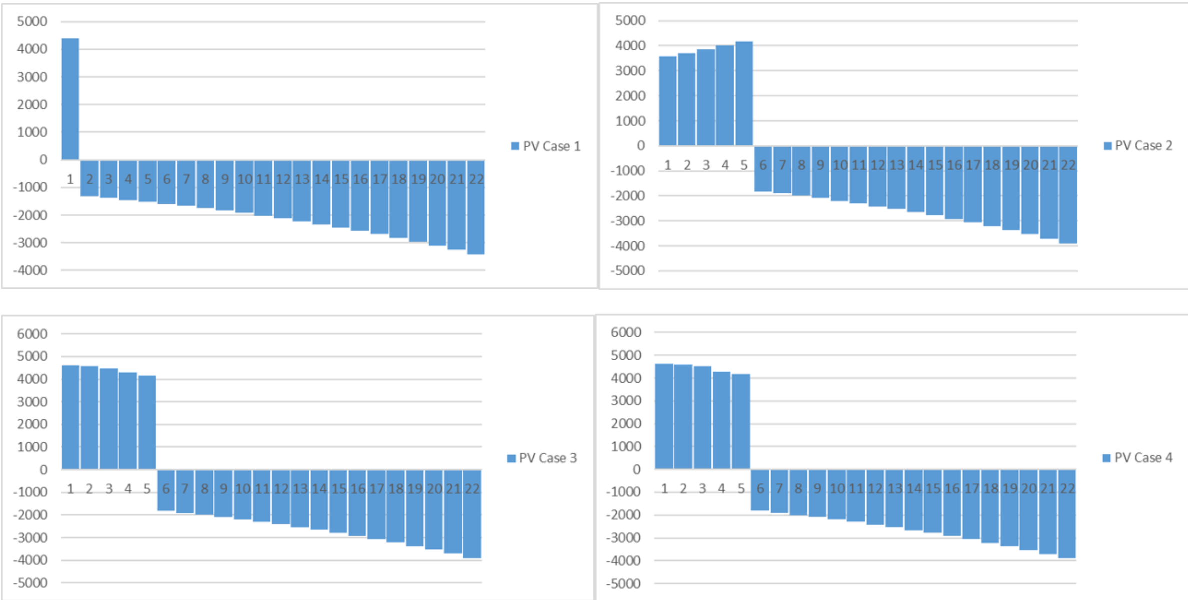

Figure 5-4: Annual Present Value Flow for All Cases in Scenario 2

Figure 5-4 displays annual PV flow for the Case 1 to 4, in Scenario 2 with 34 LIP and F2 flexibility volume. The PV-flows are calculated backwards from year 22. The negative PV reflects the remaining value of the transformers being calculated and subtracted from the cost in year 22. The annual PV is calculated as the value of the next years PV discounted with one year, added to the sum of cost in the current year. For Case 1, the PV increase in year 1 indicates the year the investment occurs. For Case 2 to 4, the investment is deferred until year 5. In Case 2, the cost of end-user flexibility is not reflected in a direct payment. The yearly PV therefore decrease from year 5 to year 0. In Case 3 and 4, the network operator issues a direct payment when using end-user flexibility. This cause an increase in PV from year 5 to 0, mainly caused by the change in costs of O&M that we saw in figure 5-2.

5.4.4 Sensitivity Analysis of Compensation Payments

The compensation method has a large impact on the economic benefits of utilizing end-user flexibility. To evaluate what effect the magnitude of the compensation payments has, we conduct a sensitivity analysis. The analysis studies how the PV in the different alternatives change if the compensations payment is changed. We study how a 10 and 20 % increase and reduction influence the PV respectively.

		Percentage Change in Compensation Rate				
LIP	Scneario & Flexibility Volume	-20 %	-10 %	0	10 %	20 %
34	S1 - F1	-1 %	0 %	0 %	0 %	1 %
	S1 - F2	-2 %	-1 %	0 %	1 %	2 %
	S2 - F1	-2 %	-1 %	0 %	1 %	2 %
	S2 - F2	-5 %	-2 %	0 %	2 %	5 %
16	S1 - F1	-7 %	-3 %	0 %	3 %	7 %
	S1 - F2	-8 %	-4 %	0 %	4 %	8 %
	S2 - F1	-15 %	-7 %	0 %	7 %	14 %
	S2 - F2	-17 %	-9 %	0 %	9 %	17 %
0	S1 - F1	-11 %	-6 %	0 %	6 %	11 %
	S1 - F2	-13 %	-6 %	0 %	6 %	13 %
	S2 - F1	-18 %	-9 %	0 %	9 %	18 %
	S2 - F2	-18 %	-9 %	0 %	9 %	18 %

Table 5-1: Changes in PV by Change in Compensation Rate for Case 3

Table 5-1 shows how changes in the compensation rate affect the PVs in Case 3. The change in compensation payments includes a percentage change in both the availability and activation simultaneously. The table shows that the effect of a price change in the alternatives with 34 % LIP have little effect on the PV, especially in Scenario 1. In Scenario 1, flexibility is only used to manage malfunctions. Since end-user flexibility is utilized less extensively, the impact of a change in payment for availability and activation therefore have a small impact on the PV. When flexibility is used more extensively, the effect of a change in compensation rate increases. The change in PV in both scenarios increase with increased flexibility volume. This reflects that the availability cost increase when more flexibility becomes available. In the cases with 34 % LIP, the investment is deferred by 3 years with F1 flexibility volume, and 4 years with F2 flexibility volume. The increase in compensation rate will therefore only affect the PV of the alternatives in years prior to the investment.

In the alternatives with 16 % LIP, we see that the changes in compensation rate have a larger impact on the PV. There are similar patterns in the different scenarios and flexibility volumes as in the alternatives with 34 % LIP. The explanation for the greater effect on PV compared to 34 % LIP is that the investment is deferred by 22 years. End-user flexibility is utilized for a longer period, which in terms makes the PV more sensitive to changes in compensation rate. The same is reflected in the change in PV for the alternatives with 0 % LIP. The effect is however stronger relatively to the basis PV in these alternatives. The PV is more sensitive to the compensation rate, since the costs related to network loss are zero in Scenario 1, and constant for the entire time span in Scenario 2. In comparison, the cost of network loss increases throughout the period with 16 percent LIP in Scenario 1, whilst it remains constant throughout the period in the same Scenario with 0 percent LIP. This is a result of the network operator having to do less redirection of priority loads when the load increase is flat.

		Percentage Change in Compensation Rate				
LIP	Scneario & Flexibility Volume	-20 %	-10 %	0	10 %	20 %
34	S1 F1	0 %	0 %	0 %	0 %	0 %
	S1 F2	0 %	0 %	0 %	0 %	0 %
	S2 F1	-1 %	-1 %	0 %	1 %	1 %
	S2 F2	-5 %	-2 %	0 %	2 %	5 %
16	S1 F1	0 %	0 %	0 %	0 %	0 %
	S1 F2	0 %	0 %	0 %	0 %	0 %
	S2 F1	-14 %	-7 %	0 %	7 %	14 %
	S2 F2	-17 %	-9 %	0 %	9 %	17 %
0	S1 F1	-1 %	0 %	0 %	0 %	1 %
	S1 F2	-2 %	-1 %	0 %	1 %	1 %
	S2 F1	-18 %	-9 %	0 %	9 %	18 %
	S2 F2	-18 %	-9 %	0 %	9 %	18 %

Table 5-2: Change in PV by Change in Compensation Method for Case 4

Table 5-2 show how changes in compensation rate affect the different PVs in Case 4. For all the different LIPs in Scenario 1, a change in compensation rate has little to no impact on the change in PV. This can be explained by the compensation method. Since the network operator only pays for activation, there are no costs for having end-user flexibility available. For Scenario 2, we see similar patterns as we saw in the sensitivity analysis of Case 3. When the utilization of flexibility and volume increase, the PV become more sensitive to the compensation rate. As in Case 3, the length of the investment deferral also has a large impact on the sensitivity for changes in compensation rate.

To summarize, the alternatives where the investment is deferred for a longer period are more sensitive to changes in the compensation method. The change in PV are lower than the change in compensation rate for all alternatives, as the PV is also affected by investment costs, cost of network loss and cost of VoLL. For the alternatives with 16 and 0 % LIP, the costs of network loss have the largest impact besides changes in O&M costs, especially in scenario 2.

5.5 Results

The downscaled present value (PV) of the costs streams will be used when discussing the results of the analysis. Because all costs are equally downscaled, the relations and comparisons remain equal to those of the original case at the regional network level. The PV is calculated using the formula:

$$Present\ Value = \sum_{t=1}^{n} \frac{C_t}{(1+r)^t}$$

Complete downscaled cost streams can be found in the Appendix. Table 5-1 display the downscaled PVs of the different alternatives.

		Scenario 1			Scenario 2		
		Load Increase Prediction			Load Increase Prediction		
Case	Flexible volume	34 %	16 %	0 %	34 %	16 %	0 %
1	-	4384	4382	4382	4384	4382	4382
2	F1	4079	1828	687	3796	712	238
	F2	3960	1816	680	3570	550	292
3	F1	4272	2745	1611	4128	2666	2591
	F2	4308	3067	1969	4618	4431	3079
4	F1	4081	1840	709	4006	2280	2404
	F2	3967	1816	737	4626	4495	2596

Table 5-3: Present Values of Different Cases and Alternatives

Both scenarios are presented with different LIPs and different volumes of flexibility. Since the analysis look at the PV of costs, a low PV is preferred by the network operator. To discuss the possible cost savings of the different flexibility alternatives, it is of interest to consider each alternative relative to the investment scenario, Case 1. Table 5-3 show the PVs of the different alternatives as a share of the investment alternative in the scenario and with the same LIP.

		Scenario 1			Scenario 2		
		Load Increase Prediction			Load Increase Prediction		
Case	Flexible volume	34 %	16 %	0 %	34 %	16 %	0 %
1	-	100 %	100 %	100 %	100 %	100 %	100 %
2	F1	93 %	42 %	16 %	87 %	16 %	5 %
	F2	90 %	41 %	16 %	81 %	13 %	7 %
3	F1	97 %	63 %	37 %	94 %	61 %	59 %
	F2	98 %	70 %	45 %	105 %	101 %	70 %
4	F1	93 %	42 %	16 %	91 %	52 %	55 %
	F2	90 %	41 %	17 %	106 %	103 %	59 %

Table 5-4: Present Values of Different Cases as a Share of Investment

Case 1 serves as the benchmark for all flexibility alternatives. The investment occurs in year one, and supply all end-users. Costs related to O&M and VoLL are low for the entire period. There are no costs related to network loss. Because the present value of the investment alternatives is close to identical for all scenarios, PVs of flexibility alternatives will be discussed and compared across rows and columns.

For all end-user flexibility alternatives with 16 or 0 percent LIP, the investment is deferred with 22 years. With 34 percent LIP, the investment is deferred until with 3 years with F1 flexibility volume, and 4 years with F2 flexibility volume. The investment years for the different alternatives in the cases are displayed in the table below.

		Scenario 1			Scenario 2		
		Load Increase Prediction			Load Increase Prediction		
Case	Flexible volume	34 %	16 %	0 %	34 %	16 %	0 %
1	-	2019	2019	2019	2019	2019	2019
2	F1	2022	2040	2040	2022	2040	2040
	F2	2023	2040	2040	2023	2040	2040
3	F1	2022	2040	2040	2022	2040	2040
	F2	2023	2040	2040	2023	2040	2040
4	F1	2022	2040	2040	2022	2040	2040
	F2	2023	2040	2040	2023	2040	2040

Table 5-5: Investment Year for Different Cases in Different Alternatives

In Case 2, flexible end-users are compensated through a tariff discount. The PV-shares are all below 100 percent, implying that all the alternatives are less costly than the investment alternative. A higher flexibility volume benefits the network operator in Case 2, since the compensation to flexible end-users is not reflected in the cost stream. When compensation is imposed as a tariff discount, the operator does not issue a direct payment to consumers. In this case, the flexibility is not reflected in O&M costs. In Case 2, the flexibility payment is imposed as a redistribution of network tariffs between flexible and non-flexible consumers. The effect of the redistribution will be discussed further in the next chapter. Having access to F2 flexibility instead of F1, reduces the PV for all alternatives, except for the alternative with 0 percent LIP in the second scenario. In this alternative, a switch of capacity is necessary to ensure supply of priority load in the second year which adds a cost to O&M in year one. Figure 5-5 displays the differences in PV of Case 2 in Scenario 1 and 2, with different flexibility volumes. The blue line reflects the PV of Case 1.

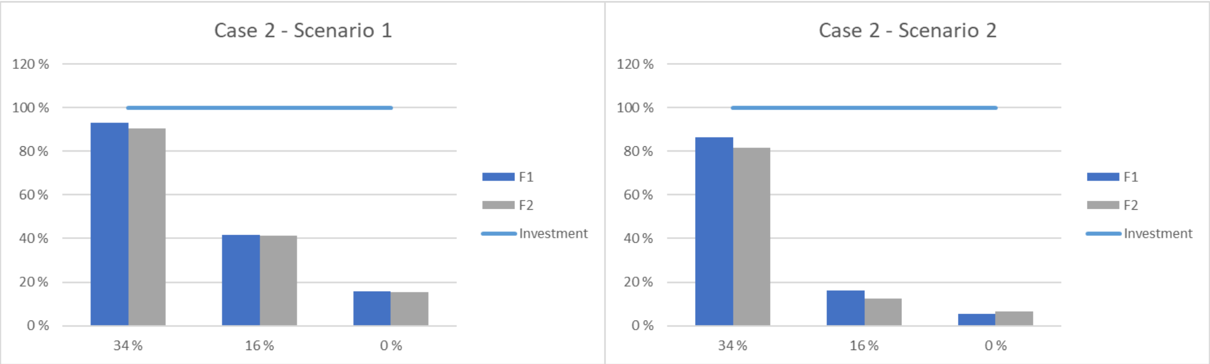

Figure 5-5: Comparison of PV for Case 2 in Both Scenarios and Case 1

From Figure 5-5, we see how Case 2 compare to the base investment case of Case 1. We observe that the PV is lower in all alternatives of Case 2 compared to Case 1. This is the case for both scenarios, both flexibility volumes and all LIPs. We also observe that F2 is the preferred flexibility volume for all LIPs, except 0% LIP in Scenario 2.

We also observe that end-user flexibility is more beneficial in Scenario 2 than Scenario 1, where it is utilized more extensively. In Scenario 2, end-user flexibility is used to both handle peaks in normal operation and in case of malfunction. Because the cost of flexibility is not directly reflected in the cost stream, costs related to handling peak loads are reduced. Based on the observations, it seems beneficial for the operator to use end-user flexibility for all volumes and all LIPs. However, flexibility is barely beneficial for a LIP of 34 percent, and other aspects might make the operator choose investment in new components if the benefits are not notably high.

For Case 3, where the operator compensates flexible end-users with an availability cost and an activation cost, we see different patterns in the PVs. The deviation between different flexibility volumes are greater compared to case two. Contrary to the second case, we see that having more flexibility is less beneficial and impose a larger cost on the operator. This is due to the compensation method. When compensating all flexible consumers for being available, the costs for the operator increase according to the flexibility volume. In addition to compensating for availability, the operator compensates for activation. This increases the cost of end-user flexibility, and the alternatives become less beneficial the higher the LIP is. This is because the network operator must respond by extending the use of end-user flexibility when the load use increases. Figure 5-6 displays the differences in PV of Case 3 in Scenario 1 and 2, with different flexibility volumes. The blue line reflects the PV of Case 1.

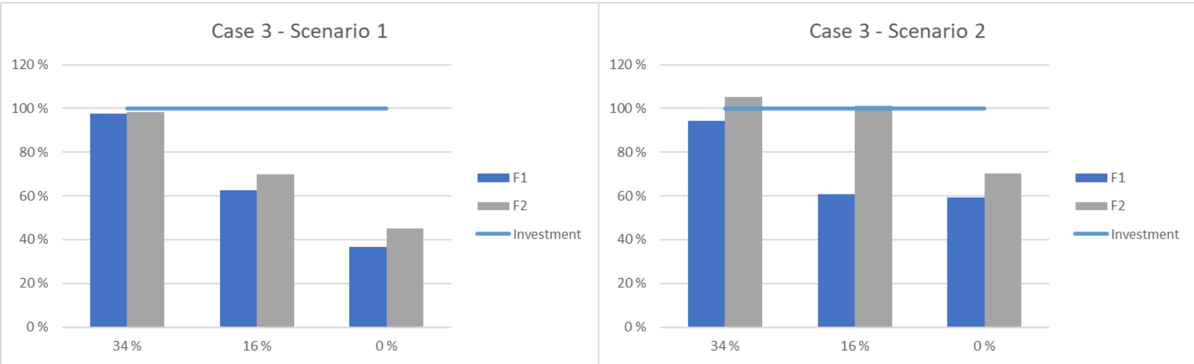

Figure 5-6: Comparison of PV for Case 3 in Both Scenarios and Case 1

From Figure 5-6, we see how Case 3 compare to the base investment case of Case 1. We observe that the PV in Case 3 is higher than the base investment Case 1 for both Scenario 2 with F2 flexibility volume and 34% and 16% LIP. Furthermore, Scenario 1 with a 34% LIP is close to Case 1. We also observe that F1 flexibility reduces the PV for both scenarios, as the investment is deferred for a shorter period. Less flexibility is utilized since less is available.

From the PVs in Case 3, we see that several flexibility alternatives are not desirable. In Scenario 2 and with F2 flexibility volume, the PV of the flexibility alternative is higher than the PV of Case 1. In Scenario 1 with 34 % LIP, the PV of Case 3 are barely lower than the PV of Case 1. All other PV-shares in Case 3 with 16 and 0 percent LIP, are lower than for Case 1, but notably higher than in Case 2. The variety in economic benefit is a direct result of the compensation method for flexibility. Including a direct payment for availability and activation increases the PV-share of all the flexibility alternatives.

In Case 4, consumers are compensated with an activation cost only. The network operator does not pay for availability in this alternative, but the activation cost is set higher than in Case 2.

In general, we see that the pattern of the PVs in scenario one is similar those in the same scenario in Case 2. For Scenario 2 in Case 4, we see that the PVs are more similar those in the same scenario in Case 4. In Scenario 1, the use of end-user flexibility is limited, as the probability of malfunction is low. In Scenario 2, the network operator extends the use of end-user flexibility, and therefore experience greater costs. The cost increase mainly occurs in O&M costs, making the PV increase. Figure 5-7 displays the differences in PV of Case 4 in Scenario 1 and 2, with different flexibility volumes. The blue line reflects the PV of Case 1.

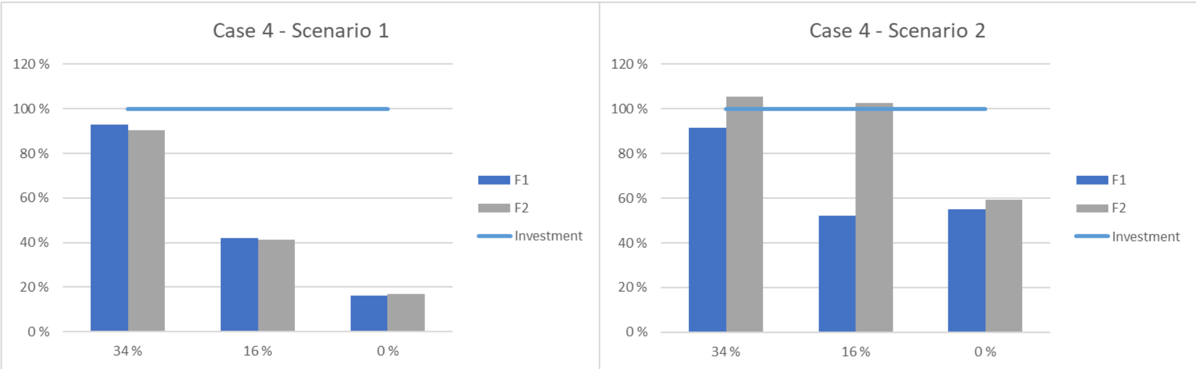

Figure 5-7: Comparison of PV for Case 4 in Both Scenarios and Case 1

From Figure 5-7, we see how Case 4 compare to the base investment case of Case 1. Similar to the observations in Case 3, we observe that the PV in Case 4 is higher than Case 1 for Scenario 2 with F2 flexibility volume and both 34% and 16% LIP. We observe that F1 is less beneficial in 34% and 16% LIP for Scenario 1, differing from the results in and Case 3, where F2 was less beneficial for all LIPs in both Scenario 1 and 2. It is worth noting that F2 flexibility volume in Scenario 2 have is much less beneficial than in Scenario 1.

For the Case 2, the PV in Scenario 2 are lower than in Scenario 1. This means that an extensive use of end-user flexibility decreases the PV. This is also reflected by the benefits of having F2 flexibility instead of F1. For Case 3 and Case 4, Scenario 2 is less desirable. In these cases, the cost of end-user flexibility is reflected in the cost stream, which makes deferring investments costlier. Because end-user flexibility is utilized to manage peak loads in addition to malfunction, the PV-shares also increase when end-user flexibility becomes costlier. Similarly, having F2 flexibility increase the PV, compared to having F1 flexibility. All alternatives with F1 flexibility have a PV-share below 100 percent. The alternatives with 34 and 16 percent LIP, and F2 flexibility in Scenario 2, is unbeneficial in Case 3 and 4. With 0 percent LIP and F2 flexibility, the PV-shares are lower than 100.

The PV-analysis is not sufficient to reflect the economic effect the investment decisions will have on the network operator. As discussed in chapter four, the revenue cap of the network operator is determined by the combination of a benchmarking model and a coverage of own costs. In the next section, the cost streams of the case are transmitted to NVE’s regulatory model for distribution networks. We seek to observe the relative impact different types of end-user flexibility will have on the revenue cap and efficiency of the network operator.

6. End-User Flexibility in the Revenue Cap Model

In the following chapter, the flexibility cases from Skagerak Nett presented in chapter five, are transferred to the regulatory revenue cap model. The previous chapter discussed 42 different alternatives. The following chapter consider the investment case under the two scenarios with 34 percent load increase prediction (LIP), and under both flexibility volumes (F1 and F2). Since all alternatives with 16 and 0 percent LIP defer the investment until year 2040, they are less relevant to discuss in terms of the current regulatory model. The regulatory model changes annually through changes in frontier companies, number of network operators, reference rates, electricity prices, inflation and the calibration pot. The regulatory model is under continuous development by NVE and affected by changes in the industry. Thus, there are greater uncertainties when considering investments in the long term. Discussing the alternatives where the investment occurs within the first 5 years in the current regulative environment is more certain, and we focus on analyzing the alternatives with 34 percent LIP under the four cases.

6.1 Evaluating Investments in Adaptiv

Before discussing the results from the analysis, we provide an explanation of the regulatory model tool, Adaptiv, used in the following chapter. The function explained is the investment prediction tool, which predict the effect an investment will have on a network operator's RC, OR, efficiency and rate of return. The changing regulatory landscape increase the uncertainty of future investments. By basing the investment analysis on historical data, we can evaluate future outcome of investments, based on the tentative outcome from previous years. The model tool displays the value of change in RC, OR and efficiency today based on the outcome if the investment was undertaken t-2 years ago. The time lag of two years before costs are reflected in the model means that the latest available accounting data is from year t-2.

Table 6-1 displays how the effect of an investment will be predicted in the model. The first column displays the year the effect of the investment is predicted for. The second and third columns shows a tentative investment depreciated linearly over 4 years. The fourth column display what year the model assumes the investment occurred to give a prediction of the impact in year t, based on historic data.

Year	Book value	Yearly Linear Depreciation	Historic Basis Year for Investment
t	75	25	t - 2
t + 1	50	25	t - 3
t + 2	25	25	t - 4
t + 3	0	25	t - 5

Table 6-1: Example of Basis Year for Investment Prediction in Adaptiv

For example, in year t, we see what changes would have occurred if the investment was undertaken in year t-2. For year t+1, we see what changes would have occurred in year t if the investment was undertaken in year t-3. For each additional year we predict for, the book value is lowered with the yearly linear depreciation. This calculation method provides tentative future values based on the outcome of investments, had they been undertaken in a previous year.

It is important to note that the model lower the tentative investment with the depreciated value. This prevents the model from treating the size of the investment as equal in all years. The yearly linear depreciation is calculated based on the size of the investment cost the year it is undertaken, it is therefore equal for all years.

By doing this, we can consider the current regulatory landscape as fixed, and study how an investment affects predicted changes for the network operator in question. Basing predictive investment outcomes on what impact the investment would have had if it had been undertaken in previous years, is therefore an alternative to making a predictive analysis that would make assumptions on future industry development.

6.2 Analysis Description

The time horizon of the analysis is extended to year 2050. This is because the time horizon of depreciation exceeds year 2040 for all alternatives.

Each case is divided into the period before and after the investment. In Case 1, the investment is undertaken in year one and there is no period before the investment occurs. Because the costs in O&M, VoLL and Network loss vary between years, we calculate an arithmetic mean with the value from the first and last year, and one year in the middle. For Case 1, cost values from year 1, 12 and 22 are used. In the alternatives with F1 flexibility volume the investment is deferred for 3 years, and the costs in year 1, 2 and 3 are used to calculate the average. In the alternatives with F2 flexibility volume the investment is deferred for 4 years, and the costs in year 1, 3 and 4 are used. Note that using the second year instead of the third have a minimal impact. An average is not calculated for the investment cost, as it is a one-time cost. The individual costs are then used as an input in the model, to see what effect the different alternatives have on the change in the revenue cap (RC) and efficiency. To compare alternatives, the NPV of the change in RC is calculated for all alternatives, using the following formula.

$$Net\ Present\ Value = \sum_{t=1}^{n} \frac{\Delta RC_t}{(1+r)^t} - I$$

The rate of return is similar to NVE's real rate of return, calculated to 4.88 percent. The assumed depreciation period of 25 years remains. In Case 1, the investment occurs in year one. For the flexibility alternatives where the investment is deferred, I is equal to zero for the years prior to the investment. The NPVs therefore only include a change in RC because of changes in costs. After calculating the NPV of utilizing end-user flexibility, the NPV of the deferred investment is calculated and depreciated with the number of deferred years. Because the time horizon is extended to 2050, there will be a period with low changes in costs of O&M, VoLL and Network loss after the investment is fully depreciated. These years after the depreciation will have a small impact on the change in RC and efficiency.

To visualize the process, an example is provided. We first provide the cost profile for the flexibility case where end-users are compensated with an availability cost of 20,000 NOK per MWh and activation costs of 20,000 NOK per MWh. Flexibility is utilized to manage peak loads in normal operations, and in the case of malfunctions. The flexibility volume in the example is F2, which includes existing flexibility and an estimated flexibility for households, and the LIP is 34 percent.

Year	Δ O&M	Δ VoLL	Δ Invest	Δ NL	Sum	PV
1	243.091	0.535	0	19.654	263.280	4523
2	275.749	0.622	0	19.654	296.026	4430
3	370.360	0.722	0	19.654	390.736	4300
4	289.775	0.539	0	28.676	318.990	4065
5	12.502	0.042	5880	0	5892.544	3896
6	0.003	0.053	0	0	0.056	-2076
7	0.004	0.066	0	0	0.069	-2159
8	0.005	0.079	0	0	0.084	-2246
9	0.005	0.095	0	0	0.100	-2336
10	0.006	0.112	0	0	0.119	-2429
11	0.008	0.132	0	0	0.139	-2527
12	0.009	0.153	0	0	0.162	-2628
13	0.010	0.175	0	0	0.185	-2733
14	0.011	0.200	0	0	0.212	-2843
15	0.013	0.227	0	0	0.240	-2957
16	0.015	0.259	0	0	0.274	-3075
17	0.017	0.293	0	0	0.310	-3198
18	0.018	0.322	0	0	0.340	-3327
19	0.020	0.353	0	0	0.373	-3460
20	0.022	0.384	0	0	0.406	-3599
21	0.024	0.417	0	0	0.440	-3743
22	0.026	0.454	-3894	0	-3893.520	-3894

Table 6-2: Cost Profile of Case 2 in Scenario 2 with 34 Percent LIP and F2 Flexibility Volume (numbers in 1,000 NOK)

The cost profile displayed in table 6-2 is used as a basis for calculating the input to the regulatory model. The investment is deferred by 4 years until year 2023.

	Before Investment		At Investment & After	
Cost	Sum	Mean	Sum	Mean
O&M	889.20	301.08	12.72	4.18
VoLL	1.88	0.60	3.81	0.23
Network Loss			0	0
Investment	58.96	22.66	5880	

Table 6-3: Input in the Regulatory Model for Case 2 in Scenario 2 with 34 Percent LIP and F2 Flexibility Volume (numbers in 1,000 NOK)

6.3 Results

When implementing the values from table 6-3, the model provides us with an output for the change in book value, linear depreciation, change in efficiency, change in revenue cap and change in operational income.

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Income	Discounted Change in Revenue Cap
2019	1	0	0	-0.04 %	158	-150	150.65
2020	2	0	0	-0.04 %	158	-150	143.64
2021	3	0	0	-0.04 %	158	-150	136.96
2022	4	0	0	-0.04 %	158	-150	130.58
2023	5	5 645	235	-0.05 %	385	149	303.39
2024	6	5 410	235	-0.05 %	374	138	281.01
2025	7	5 174	235	-0.05 %	363	127	260.05
2026	8	4 939	235	-0.05 %	351	115	239.75
2027	9	4 704	235	-0.05 %	340	104	221.43
2028	10	4 469	235	-0.04 %	329	93	204.30
2029	11	4 234	235	-0.04 %	318	82	188.28
2030	12	3 998	235	-0.04 %	306	70	172.75
2031	13	3 763	235	-0.04 %	295	59	158.79
2032	14	3 528	235	-0.04 %	284	48	145.75
2033	15	3 293	235	-0.04 %	273	37	133.59
2034	16	3 058	235	-0.04 %	261	25	121.77
2035	17	2 822	235	-0.04 %	250	14	111.22
2036	18	2 587	235	-0.04 %	239	3	101.37
2037	19	2 352	235	-0.04 %	228	-8	92.21
2038	20	2 117	235	-0.04 %	216	-20	83.29
2039	21	1 882	235	-0.04 %	205	-31	75.37
2040	22	1 646	235	-0.04 %	194	-42	68.01
2041	23	1 411	235	-0.03 %	183	-53	61.17
2042	24	1 176	235	-0.03 %	171	-65	54.50
2043	25	941	235	-0.03 %	160	-76	48.62
2044	26	706	235	-0.03 %	149	-87	43.17
2045	27	470	235	-0.03 %	138	-98	38.12
2046	28	235	235	-0.03 %	126	-110	33.19
2047	29	0	235	-0.03 %	115	-121	28.88
2048	30	0	0	0.00 %	0	-1	0.00
2049	31	0	0	0.00 %	0	-1	0.00
2050	32	0	0	0.00 %	0	-1	0.00

Table 6-4: Output from the Regulatory Model in Case 2 in Scenario 2 with 34 percent LIP and F2 Flexibility Volume (numbers in 1,000 NOK)

Table 6-4 display the output from the regulatory model tool. The discount rate is set to zero in table 6-4. The rate will be included when the PV and NPV are calculated in table 6-4. The column with changes in RC is used to calculate the NPV of the changes in RC. End-user flexibility is utilized for 4 years. The investment is undertaken in year 2023, and the value of the investment is depreciated until 2047. From year 2048 to 2050, there are only the change in costs for O&M, VoLL and Network loss from the column named *At Investment & After* in table 6-3 that is used as input. The change in RC is therefore close to zero for the years after the investment is fully depreciated.

Year	Year (number)	Change in Revenue Cap	Discounted Change in Revenue Cap	PV	NPV
2019	1	158	150.65	3831.85	-1027.86
2020	2	158	143.64		
2021	3	158	136.96		
2022	4	158	130.58		
2023	5	385	303.39		
2024	6	374	281.01		
2025	7	363	260.05		
2026	8	351	239.75		
2027	9	340	221.43		
2028	10	329	204.30		
2029	11	318	188.28		
2030	12	306	172.75		
2031	13	295	158.79		
2032	14	284	145.75		
2033	15	273	133.59		
2034	16	261	121.77		
2035	17	250	111.22		
2036	18	239	101.37		
2037	19	228	92.21		
2038	20	216	83.29		
2039	21	205	75.37		
2040	22	194	68.01		
2041	23	183	61.17		
2042	24	171	54.50		
2043	25	160	48.62		
2044	26	149	43.17		
2045	27	138	38.12		
2046	28	126	33.19		
2047	29	115	28.88		
2048	30	0	0.00		
2049	31	0	0.00		
2050	32	0	0.00		

Table 6-5: Present Value and Net Present Value for Case 2 in Scenario 2 with 34 percent LIP and F2 Flexibility Volume (numbers in 1,000 NOK)

Table 6-5 includes the change in RC and discounted change in RC for the different alternatives. The utilization of end-user flexibility is implemented as an average cost increase in O&M, VoLL and Network Loss. Thus, the absolute change in RC will be constant over the period when end-user flexibility is used to defer the investment. The value of changes in RC from the investment diminish towards the end of the depreciation period, since the book value of the investment diminishes yearly with the depreciation. Lowering the book value will lower the change in RC, as it is included in both the cost base and cost norm of the RC equation. Increasing the book value of the network operator therefore increase RC. When the changes in RC are discounted, the values towards the end of the period becomes lower, as they have a lower value today.

When summing up the discounted changes in RC, we get the PV of the end-user flexibility alternative. From the table, we see that the value is 3,832 NOK. To get the NPV, we subtract the investment cost in the alternative, discounted for four years. Four years is the duration the investment is deferred. The NPV is -1,028 NOK, indicating that the project is not economically desirable. All the alternatives are necessary reinvestments to ensure security of supply, and do not increase the output of the company. Because of this, all the alternatives have a negative NPV-value.

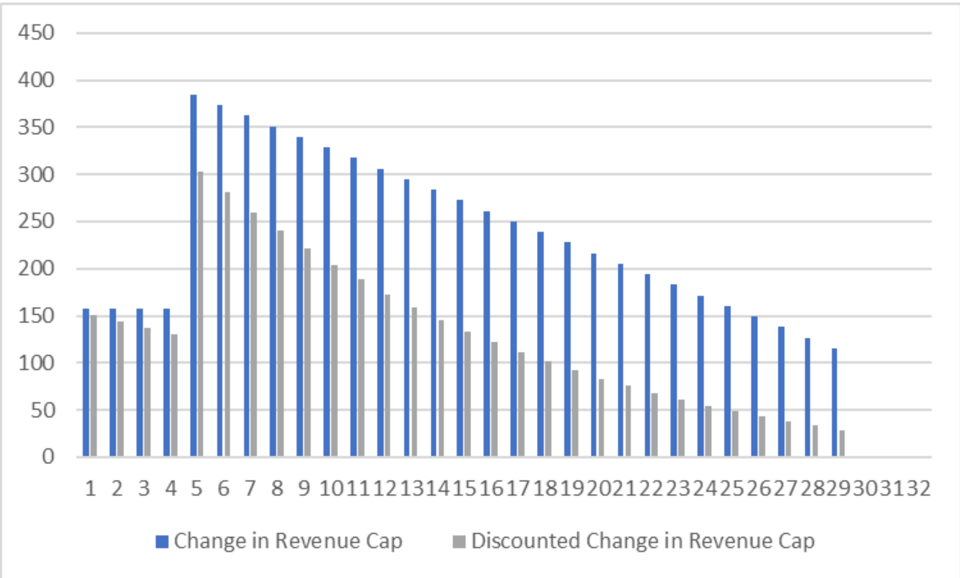

Figure 6-1: Change in RC and discounted RC for Case 3 in Scenario 2 with F2 flexibility (numbers in 1,000 NOK)

Figure 6-1 shows the change in RC and discounted change in RC for the alternative in Case 3, exemplified above. The figure shows that the absolute change in RC is constant from year 1 to 4. It increases at the year of the investment, but diminishes yearly in accordance to the depreciation. The discounted changes in RC are lower, as the future changes in RC have a lower value today.

The change in efficiency is negative to the network operator since the input of the network operator increases without a corresponding increase in output. The network operator therefore increases costs to fulfill the tasks, and becomes less effective compared to its virtual company on the efficiency frontier. The changes in efficiency is mainly interesting to discuss in the first year, because of the continuous changes in the model. The use of flexibility in Case 2 under Scenario 2 with F2 flexibility volume reduces the efficiency by approximately 0.04 percent in the first year.

6.3.1 Changes in Revenue Cap

The discussion will now consider the different cases under the two scenarios. All NPV are calculated in the same manner as in the previously explained example.

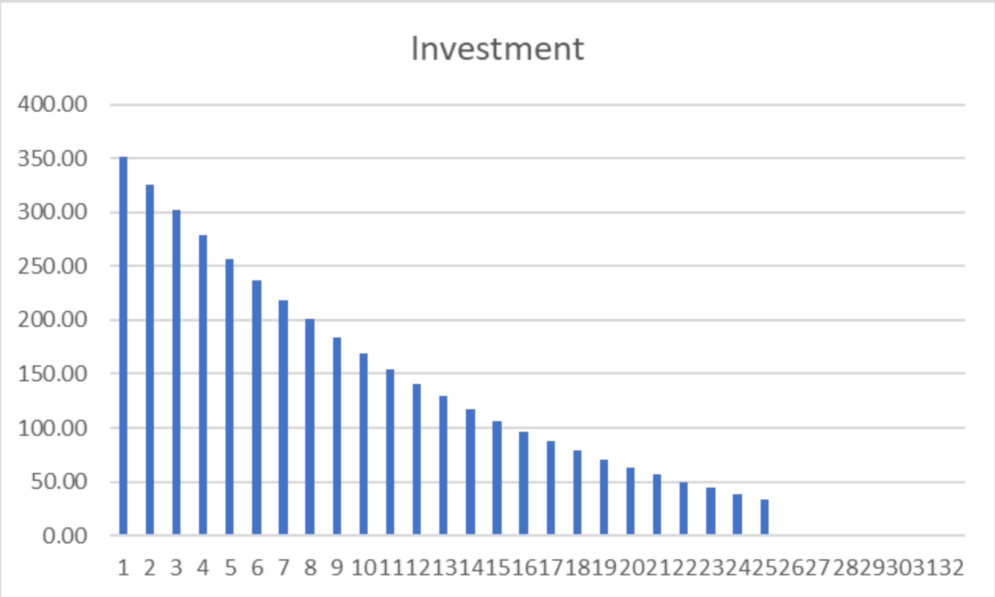

Figure 6-2: Discounted Change in RC for Case 1

Figure 6-2 displays the discounted change in RC for Case 1. We see that the investment has a greater influence on the change in RC in the beginning of the time period, and that the change diminishes towards the end of the period in accordance with the reduction in book value of the investment caused by depreciation.

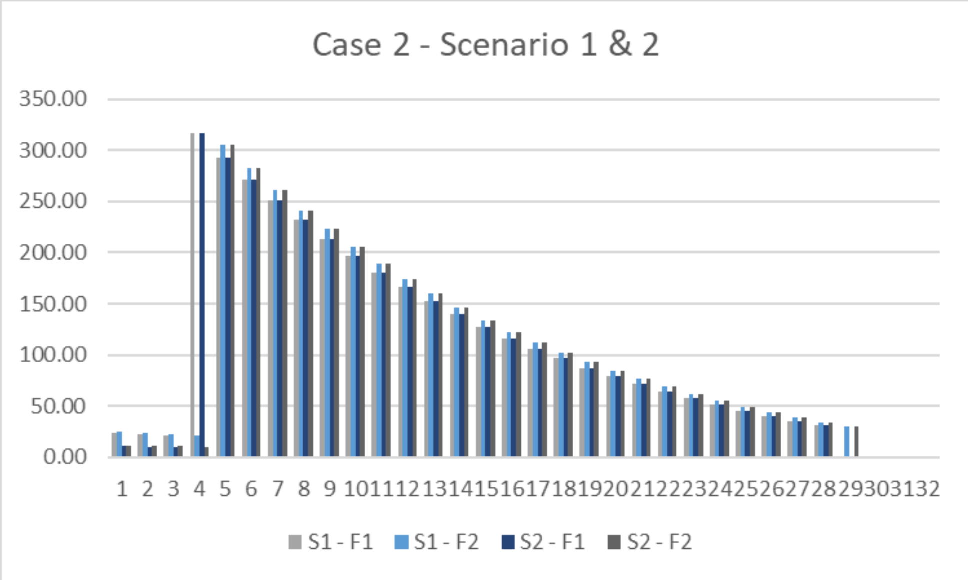

Figure 6-3: Discounted Change in RC for Case 2

Figure 6-3 displays the change in RC when end-user flexibility is compensated by a tariff discount. With F1 flexibility, the investment is deferred until years 4. With F2 flexibility, the investment is deferred until year 5. This investment deferral depends on the flexibility volume, and is therefore identical for all the investment cases. We see that the change in RC is low for the year prior to the investment. The change in RC is lower for Scenario 2 than for Scenario 1. When the investment is undertaken, we get a change in RC similar to Case 1. However, because the investment is deferred, the discounted value of the change in RC from the investment is lower than for Case 1.

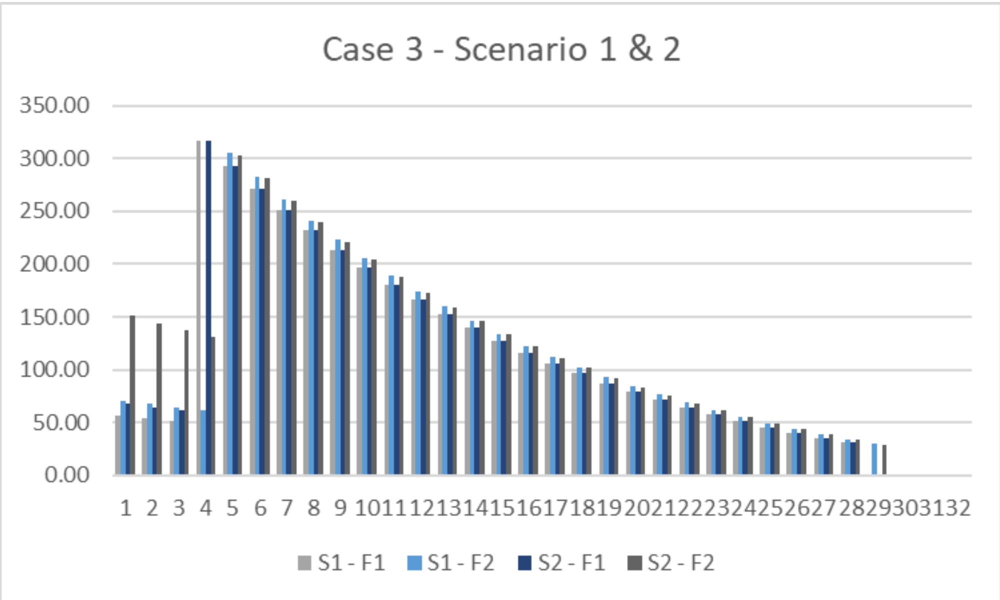

Figure 6-4: Discounted Change in RC for Case 3

Figure 6-4 displays the change in RC when end-user flexibility is compensated by a direct payment for availability and activation. We see that the change in RC is now higher for the years prior to the investment, especially in Scenario 2 with F2 flexibility. The change in RC is higher for Scenario 2 than for Scenario 1. Having access to more flexibility is now more expensive to the operator, because they have a direct payment for availability and activation. When the investment is undertaken, we get a change in RC similar to Case 1.

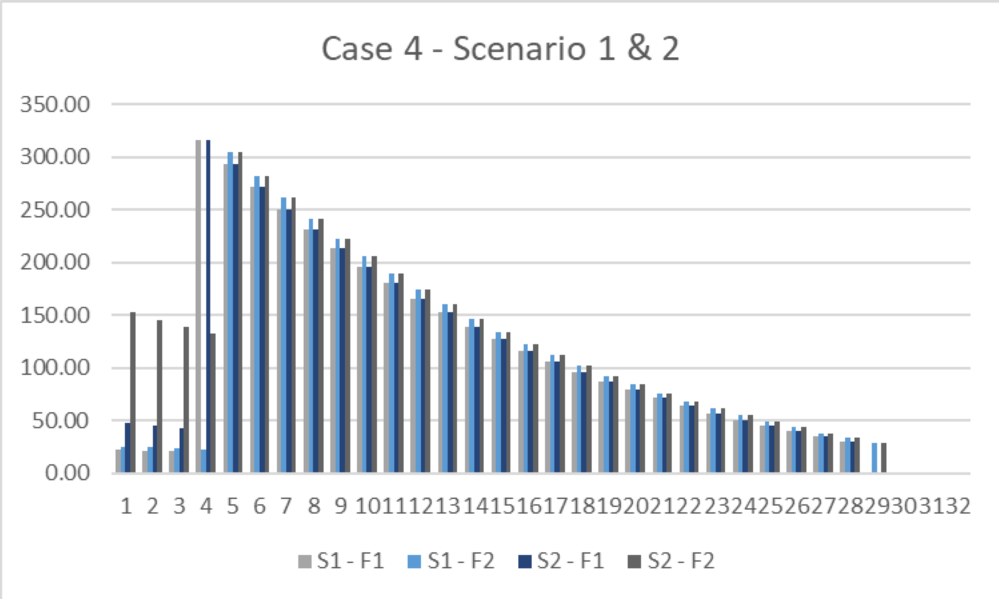

Figure 6-5: Discounted Change in RC for Case 4

Figure 6-5 displays the change in RC when end-user flexibility is compensated by a direct payment for activation. Like in Case 3, we see that the change in RC is now higher for the years prior to the investment, especially in Scenario 2 with F2 flexibility. The change in RC is higher for Scenario 2 than for Scenario 1, and having access to F2 flexibility instead of F1 increase the change in RC. The change in RC for Scenario 1 is low, because the use of flexibility limited to malfunctions. Because the network operator does not pay for availability, as opposed to Case 3, they do not pay for end-user flexibility unless it is used. When the investment is undertaken, we get a change in RC similar to Case 1.

		NPV-values of Change in RC	
		Scenario 1	Scenario 2
Case	Flexibility Volume	34 percent LIP	34 percent LIP
1	-	-1586.85	-1586.85
2	F1	-1559.56	-1595.04
	F2	-1473.79	-1523.57
3	F1	-1464.03	-1431.28
	F2	-1303.11	-1027.86
4	F1	-1559.56	-1488.59
	F2	-1470.23	-997.30

Table 6-6: Net Present Value of All Alternatives with 34 percent LIP (numbers in 1,000 NOK)

Table 6-6 display the NPV of all the different alternatives of all cases under both scenarios with 34 percent LIP and the two flexibility volumes. The NPV values are calculated as discounted investment cost subtracted from the sum of discounted changes in RC. Because the cases consider cost profiles, the alternatives with a NPV closer to zero is more desirable to the operator in terms of cost coverage. From table 6-6 we see that flexibility Cases 3 and 4, where end-users are compensated by a direct payment for flexibility, have a NPV closer to zero than Case 1 and 2. The regulatory model compensates for cost increases through the cost basis and the cost norm. The greater the cost is to the operator, the greater the change in RC. The alternative with the highest NPV is Case 4 in Scenario 2, with F2 flexibility. End-users are compensated through an activation payment, and flexibility is used both to handle peak loads and in case of malfunctions. The second highest NPV is for Case 3 under Scenario 2, with F2 flexibility. Both these alternatives had the highest PV in the previous analysis in chapter five. Because the costs are compensated in the regulatory model, the costlier alternatives receive a higher reimbursement. Compared to Case 1 all flexibility cases, except Case 2 with F1 flexibility volume in Scenario 2, have a higher NPV. Based on the observed NPV, the network operator can therefore receive a higher change in RC from using end-user flexibility with a direct payment to defer the investment.

		Internal Rate of Return	
		Scenario 1	Scenario 2
Case	Flexibility Volume	34 percent LIP	34 percent LIP
1	-	0.6351 %	0.6351 %
2	F1	0.7912 %	0.7248 %
	F2	0.8406 %	0.7451 %
3	F1	0.9739 %	1.0380 %
	F2	1.1816 %	1.7538 %
4	F1	0.7912 %	0.9264 %
	F2	0.8475 %	1.8523 %

Table 6-7: Internal Rate of Return for All Cases With 34 Percent LIP

From table 6-7 we see the Internal Rate of Return (IRR) for the different alternatives. All IRR are lower than the expected rate of return, which in our analysis is NVE's reference rate. The alternatives with the highest IRR are in Scenario 2 with F2 flexibility in Case 3 and 4. Here, the IRR are close to 2 percent. The IRR in Scenario 2 for Case 3 and 4 are similar, which corresponds to the observations made in the PV values. For Scenario 1, the values in Case 2 and 4 are similar. This is also similar to the pattern observed in the analysis in the previous chapter. All the flexibility alternatives have a higher IRR than the investment alternative, indicating that using end-user flexibility to defer the investments is desirable.

There are notable differences in the IRR between the different flexibility cases. In Case 2, where end-users are compensated through a tariff discount, the IRR are closest to those of Case 1, although higher. When including an availability and activation cost for flexibility, the IRR increase. The NPV is less negative when the network operator has access to household flexibility in addition to existing flexibility. This corresponds to the cost of end-user flexibility increasing when the access to flexibility volumes also increase. The same can be seen in the difference in IRR between the two scenarios. In Scenario 2, the operator uses end-user flexibility more extensively, as opposed to Scenario 1. The same observation can be made for Case 4, where end-users are compensated through an activation cost. With F2 flexibility volume, the IRR increases. Similarly, the IRR of Scenario 2 are greater than for Scenario 1 because end-user flexibility is used more extensively. With F1 flexibility, the IRR are higher in Case 3 than in Case 4. This can be explained with less flexibility being available to the network operator. The availability cost therefore outweighs the difference in activation costs between the two cases, which results in higher cost for Case 3. The same is observed in F2 flexibility in Scenario 1 being larger for Case 3 than Case 4.

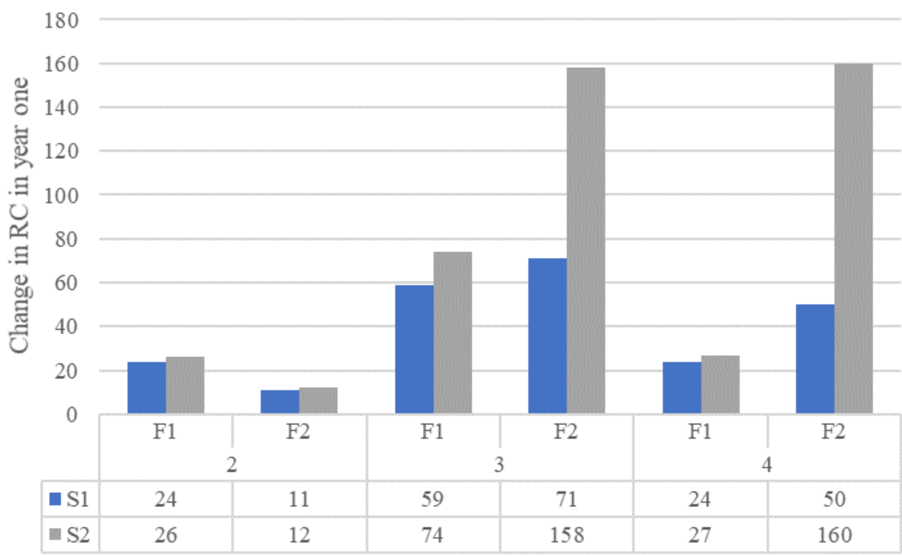

Figure 6-6: The Change in Revenue Cap in Year One for the Different Flexibility Cases (numbers in 1,000 NOK)

Figure 6-6 shows the change in RC for year one, for the different flexibility cases under the two scenarios and with the different flexibility volumes. Because the weighted average of costs is used as input in the RC-model, the yearly change in RC from using end-user flexibility will remain constant for the different cases and alternatives, before the value is discounted. Figure 6-6 show that Case 2 have the highest change in RC when end-user flexibility is only used in case of malfunctions (S1). When end-user flexibility is used to manage peaks in normal loads in addition to malfunctions, Case 4 with F2 flexibility volume is slightly higher than the same alternative in Case 3. The change in RC for year one corresponds with the NPVs for the different alternatives in the flexibility cases, displayed in table 6-6.

The change in the operator's rate of return (RoR) from the different cases and alternatives varies little. The current RoR for the operator is 7.55 percent. In the investment case, the RoR is reduced to 7.54 percent for the first 4 years after the investment is undertaken. For the flexibility cases, the RoR is 7.55 percent for the years the investment is deferred. Because the investment reduces the rate of return by approximately 0.01 percent more, the network operator can defer the reduction in RoR by 3 or 4 years, depending on the flexibility volume available.

6.3.2 Changes in Efficiency

In addition to looking at the change in RC, we display the change in efficiency for the different alternatives. The change in efficiency from the project will have an impact on the future revenue cap of the network operator. It is important to note that Skagerak Nett is a large network operator, so the impact on efficiency is not very large. However, it will still be possible to compare the relative change in efficiency between the cases.

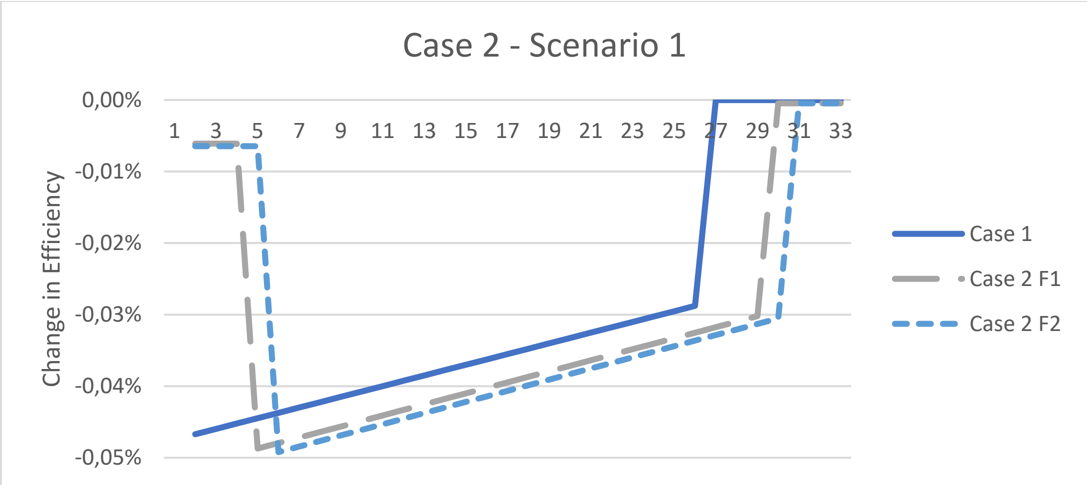

Figure 6-7: Change in Efficiency for Case 2 in Scenario 1

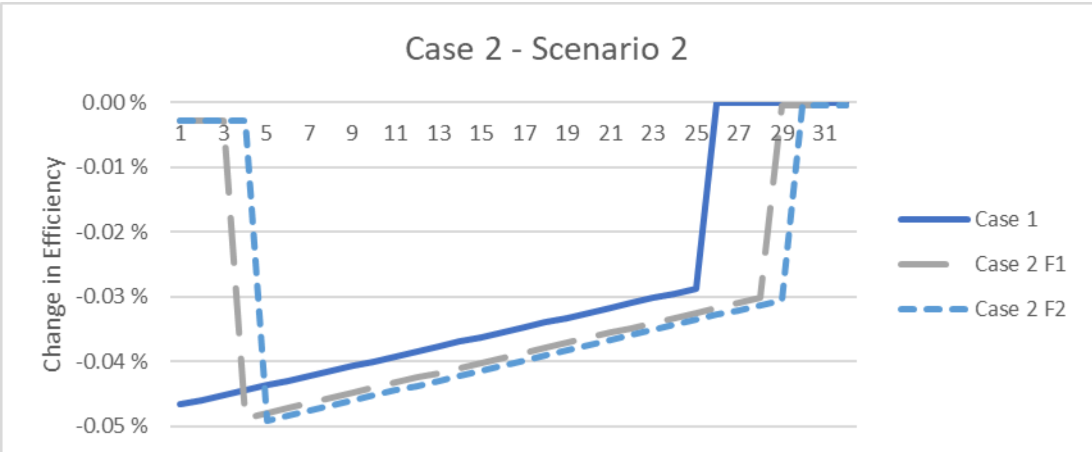

Figure 6-8: Change in Efficiency for Case 2 in Scenario 2

Figure 6-7 and 6-8 display the change in efficiency for Case 2 in the two scenarios, and with different flexibility volumes. The figures show that the operator can defer the efficiency reduction of the investment by using end-user flexibility. We see from the figures that the negative efficiency change from using end-user flexibility in Case 2 is lower for Scenario 2 than Scenario 1. This is a result of the network operator using end-using end-user flexibility more extensively in Scenario 2, without having a direct payment for flexibility.

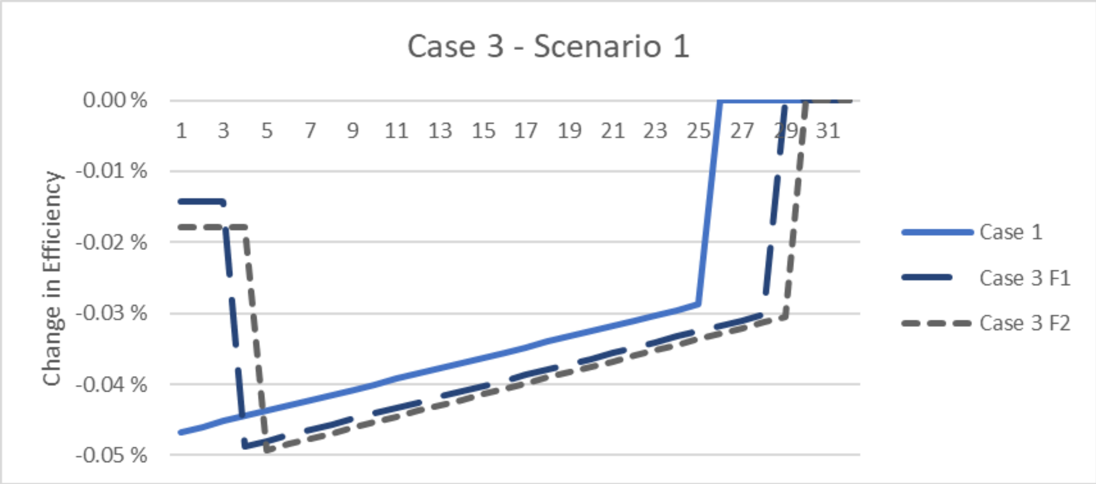

Figure 6-9: Change in Efficiency for Case 3 in Scenario 1

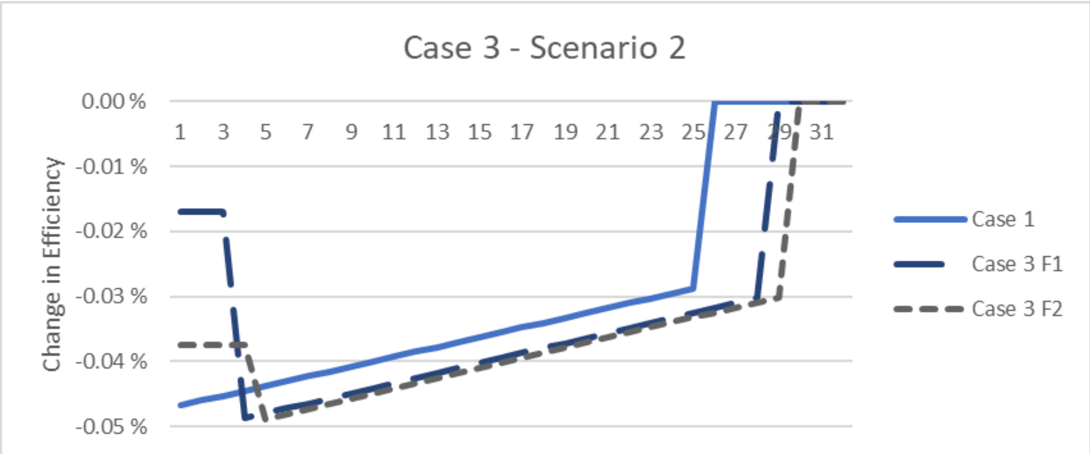

Figure 6-10: Change in Efficiency for Case 3 in Scenario 2

Figure 6-9 and 6-10 display the change in efficiency for Case 3 in the two scenarios, and with different flexibility volumes. We see from the figures that the negative efficiency change from using end-user flexibility in Case 3 is lower for Scenario 1 than Scenario 2. This is a result of end-user flexibility now being costlier due to a compensation as a direct payment. Because the network operator uses end-user flexibility more extensively in Scenario 2, the reduction in efficiency is greater. Similarly, we see that the efficiency reduction is greater in Scenario 2 with F2 flexibility, as the network operator has more flexibility available to manage peak loads.

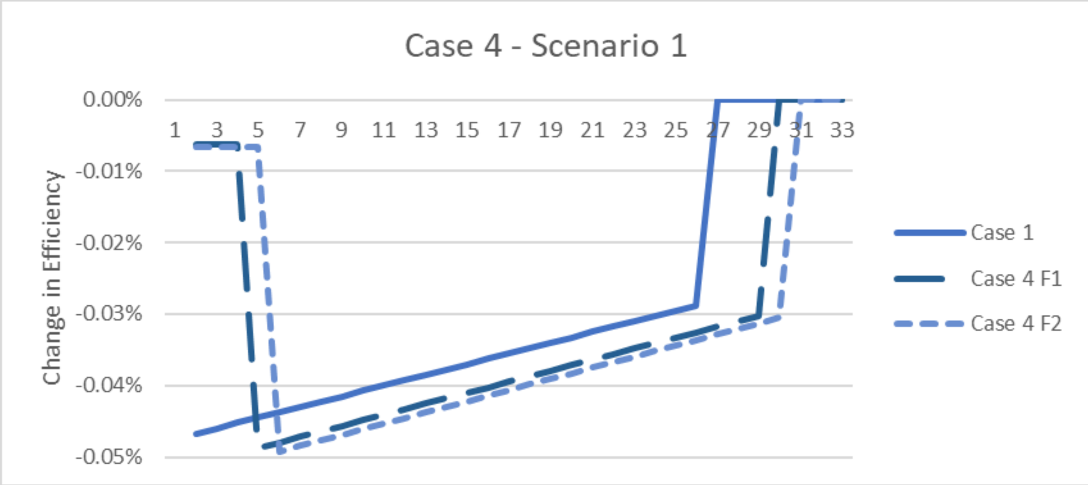

Figure 6-11: Change in Efficiency for Case 4 in Scenario 1

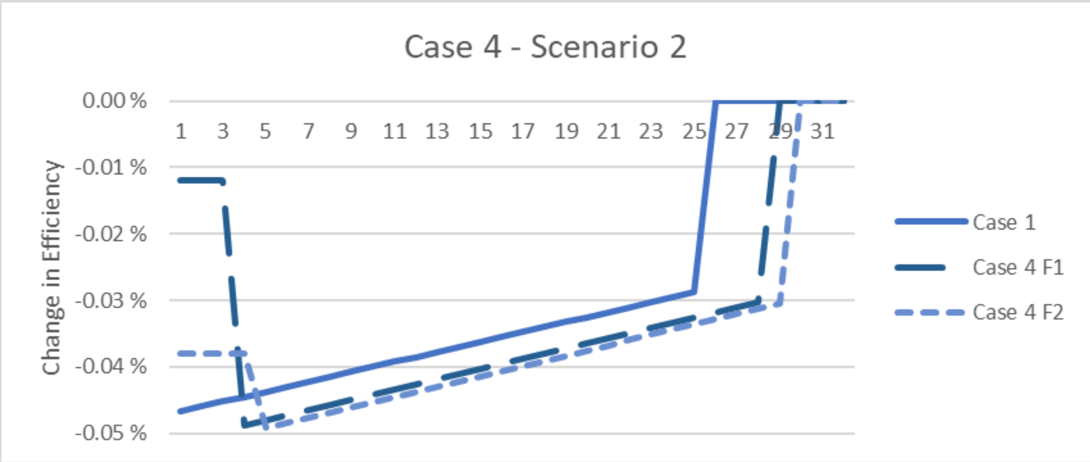

Figure 6-12: Change in Efficiency for Case 4 in Scenario 2

Figure 6-11 and 6-12 display the change in efficiency for Case 4 in the two scenarios, and with different flexibility volumes. We see from the figures that the negative efficiency change from using end-user flexibility is lower for Scenario 1 than Scenario 2. The explanation is the same as for Case 3, end-user flexibility now being costlier due to a compensation as a direct payment. Because the network operator uses end-user flexibility more extensively in Scenario 2, the reduction in efficiency is greater. Similarly, we see that the efficiency reduction is greater in Scenario 2 with F2 flexibility, as the network operator has more flexibility available to manage peak loads. Compared to Case 3, we see that the efficiency reduction in Scenario 1 is lower, because the network operator does not pay to have flexibility available, only to activate it. The same explains the relatively lower efficiency reduction in Scenario 2 with F1 flexibility.

		Change in efficiency (year 1)	
		Scenario 1	Scenario 2
Case	Flexibility Volume	34 percent LIP	34 percent LIP
1	-	-0.0467 %	-0.0467 %
2	F1	-0.0061 %	-0.0028 %
	F2	-0.0065 %	-0.0029 %
3	F1	-0.0143 %	-0.0171 %
	F2	-0.0178 %	-0.0375 %
4	F1	-0.0062 %	-0.0120 %
	F2	-0.0067 %	-0.0380 %

Table 6-8: Change in Efficiency for Year 1 in the Different Cases

Table 6-8 show that the change in efficiency for the first year is greatest for Case 1, where it is close to 0.05 percent. The investment occurs in year one, and hence the investment cost is imposed on the network operator the same year.

For the different flexibility cases, the differences in efficiency change in the years prior to the investment are large. The lowest efficiency change is in Case 2, where flexible end-users are compensated with a tariff discount. The efficiency reduction is approximately 0.006 percent in Scenario 1, and 0.003 percent in Scenario 2. This efficiency change is lower than for the other flexibility cases, because there is no direct payment to end-users for flexibility.

For Case 3, the reduction in efficiency with F1 and F2 flexibility volume in Scenario 1, is approximately 0.014 and 0.018 respectively. When increasing the utilization of end-user flexibility in Scenario 2, the reduction in efficiency is 0.017 percent with F1 flexibility volume, and 0.0375 percent with F2 flexibility volume.

The changes in efficiency for the Scenario 1 in Case 4 are similar to those in Scenario 1 in Case 2, approximately 0.0065 percent. However, for Case 4, we observe the largest efficiency reduction of all the flexibility cases in Scenario 2 with F2 flexibility volume. Here we observe a reduction in efficiency of approximately 0.04 percent. With F1 flexibility volume, the reduction is 0.012 percent.

In all the cases in our analysis the investment will be undertaken at some point. The changes in efficiency of the different alternatives therefore reflect what effect the network operator may expect end-user flexibility to have on their efficiency in the period of deferral. Because the investment only affects the input side and not the output side of the DEA, the operator will be considered less efficiency in providing its tasks in all the cases.

Based on the changes in efficiency, the case with compensation through tariff discounts is preferable to the operator, as it has the least negative effect on efficiency. As observed, the greatest efficiency reduction in the first year is in Case 1. However, the investment is undertaken at a later stage in all flexibility cases with 34 percent LIP. Despite the efficiency reduction being greater in year one for the investment case, the overall efficiency reduction for the whole period can be considered lower because the efficiency change in the years after the investment is depreciated is close to zero. Using end-user flexibility to defer the investment imposes a negative effect on efficiency in the short run, and may therefore have a more negative overall effect on efficiency, dependent on how the network operator value future change in efficiency. The long term predicted efficiency change is uncertain, due to changes in the model and the industry, so the short term predicted efficiency change are likely to be of greater interest to the network operator.

6.3.3 Compensation Methods

For the analysis in this thesis, compensation of end-users has been divided into three cases. It is interesting to discuss how the different compensation methods affect both the PV in chapter five, and the NPV and IRR from the regulatory model in this chapter. The results of the flexibility cases differ according to the utilization of end-user flexibility and the volume. The explanation of the notable differences is the effects end-user flexibility has on the compensation costs in the different cases.

In Case 3 and 4, the end-users are compensated with a payment for availability and activation. The direct payments increase the costs of the flexibility, which causes a greater change in RC, and a greater reduction in efficiency change compared to Case 2. In Case 3, the cost of end-user flexibility is greater for both flexibility volumes in scenario one, and with F1 flexibility volume in Scenario 2. The alternative in Case 4 with F2 flexibility volume in Scenario 2 is the costliest of the flexibility alternatives. The latter is reflected by the NPV of change in RC being the highest of all alternatives.

In Case 2, the changes in RC when the investment is deferred, are lower. This also lower the efficiency reduction. The IRR is higher for all alternatives in Case 2, compared to Case 1. This means that the network operator can achieve a higher IRR by using end-user flexibility, without having a significant reduction in efficiency. The case differs notably from the other flexibility cases, as there are no direct payments for flexibility. To compensate the end-user, the network operator redistributes the revenue cap amongst existing consumers. This will be reflected in lower network tariffs for flexible end-users, and higher network tariffs for non-flexible end-users. Despite having a small increase in RC when using end-user flexibility in Case 2, the main change in network tariffs for consumers will have to come from the redistribution. When redistributing between flexible and non-flexible end-users, the larger share of change in RC can be expected assigned to non-flexible end-users. Despite the change in RC being lower for Case 2 relatively to the two other flexibility cases, some non-flexible end-users might experience a greater increase in network tariffs in Case 2. This compensation method of redistribution in network tariffs is unlikely to be accepted by end-users or the regulator, but can be favorable to network operators as it has the lowest impact on efficiency and liquidity.

The compensation methods also impose a challenge to the neutrality principal. Negotiations of flexibility prices could result in a differentiation between end-users. Estimates for value of lost load for different consumer segments are currently used by operators. Because they differ notably between groups, there might have to be a regulated market place for trading flexibility, instead of a direct contact between the operator and customer, or between the operator and a third-party participant. If trading of flexibility is not regulated and standardized, the network operators could have incentives to prioritize end-users that accept lower prices. Since different end-users exhibit different consumption patterns, it can be expected that larger end-users with higher electricity usage will be willing to accept a lower payment per MWh or kWh of flexibility. One can therefore argue that household flexibility is likely to be less desirable in flexibility trading. It is important to note that end-users outside the local distribution network circuit will also be affected by a change in the revenue cap. This means that the costs of end-user flexibility at a local distribution level in the network can increase the network tariffs for end-users at other local distribution levels through an increase in RC.

7. Conclusion

The European Commission stresses the need to face the challenges of the future electricity systems. This includes incentivizing end-user participation in electricity markets. Network operators are required to improve their network systems to account for flexible end-users, local storage and distributed generation. Meanwhile, national regulators are responsible for assuring functioning regulatory frameworks for market participants. The regulator must incentivize investments in aging infrastructure, but also put ensure that network operators investigate alternative technologies for load management. Academic research on utilizing end-user flexibility in investment decisions mainly discuss how investments in the network can be deferred. There is a strong academic interest in analyzing how end-user flexibility can reduce costs while fulfilling the strict criteria of security of supply.

From an analysis of the present values in an investment case provided by Skagerak Nett, we observe possible savings related to the use of end-user flexibility. Deferring investments by compensating end-users with a tariff discount or direct payment was beneficial in many of the investigated alternatives. Overall costs for a network operator can be notably reduced in both managing transformer malfunctions alone, or with peak load management in addition. The dimension of the network is decided by peak loads that rarely occur, and end-user flexibility can be used in the few critical hours where capacity is challenged. Deferring the investment increase the utilization of existing components, and reduce the present value of future investment costs.

In all the cases discussed in this thesis, we saw that the net present value of the change in revenue cap could be influenced by utilizing end-user flexibility. The choice of compensation method has a notable impact on the change in revenue cap and efficiency in the regulatory model. Direct payments for availability and activation is reflected by a greater increase in costs, which in turn increase the revenue cap. Increasing the flexibility volume and utilization level when end-users are compensated through direct payments, impose a greater increase in revenue cap, and a more negative effect on efficiency. However, using end-user flexibility to defer investments resulted in more desirable internal rate of return than the traditional investment case, for all flexibility alternatives. The negative effect on efficiency change with a direct payment compensation was also lower in the short run for all flexibility alternatives.

If the compensation method includes a redistribution of tariffs, the impact on change in revenue cap is small. As the compensation method does not impose a direct payment, it is not reflected by an increase in costs. The change in efficiency is also lower than for the investment case and the other flexibility cases with compensation through direct payments. The operator therefore benefits from cheaper end-user flexibility in terms of efficiency change.

The notable difference between the compensation methods in the different flexibility cases highlights a challenge in the regulation of end-user flexibility. When end-user flexibility is activated with direct payments, it will be reflected in lower efficiency and a higher revenue cap. If activated through a redistribution of network tariffs between flexible and non-flexible end-users, it will have a marginal effect on both efficiency and change in revenue cap. The network operator can therefore defer the investment without a notable increase in the revenue cap or change in efficiency. Redistributing network tariffs between end-users impose regulatory challenges, as non-flexible end-users would compensate flexible end-users. Whilst compensation methods with direct payments impose a cost to the network operator, a compensation through redistribution of the revenue cap only impose a redistribution of income. Network operators are likely to prefer a redistribution of network tariffs between consumers, as they maintain close to unaffected efficiency wise. The latter shows that the regulatory model treat the effect of compensation methods differently.

The Norwegian regulator faces challenges on how the flexibility markets of the future should be managed, and what role they should assume. Regulatory authorities must ensure non-discrimination and neutrality in flexibility markets, but also ensure that security of supply is maintained.

8. Further Research

In order to analyze end-user flexibility in the current regulatory framework, we have had to make several assumptions.

We assumed that the available end-user flexibility in the cases are already aggregated. Currently, a clear overview of how much flexibility is available at end-user level, is lacking. In this regard, wide scale mapping of flexibility volumes at end-user level is necessary, and would be interesting to conduct.

Our analysis discussed the impact on end-user flexibility in a single distribution network operated by one network operator. It would be interesting to investigate how implementation of end-user flexibility in a large scale could impact the outcome of the regulatory model for the entire industry.

How a flexibility market should be structured, what participants can be expected, which products will be offered, and several other interesting questions remain unanswered. How a market design for flexibility is developed will also affect the current role of DSOs, the regulator and other current participants. At the national and international level, current research on these solutions include very different views, and a common approach is yet to be decided.

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Appendix

The reference rate of NVE

$$r = (1 - G) \times \left[\frac{Rf + Infl + \beta_e \times MP}{1 - s}\right] + G \times (Swap + KP)$$

G: fixed debt share at 60 percent

Rf: fixed neutral rate at 2.5 percent

$Infl$: adjustment for yearly inflation calculated as the average of the actual inflation in the two most recent years based on KPI, and an estimation of the two coming years. If the average is negative, the value is set as equal to zero. The calculation is based on numbers from the Norwegian Bureau of Statistics (SSB).

β_e: Private equity beta, fixed at 0.875

MP: Fixed market premium at 5 percent

$Swap$: Yearly average of a 5-year swap rate at the two of the largest banks in Norway

KP: Yearly average industry specific risk premium given as the spread between 5 year energy obligations and 5-year swap rates at two of the largest banks in Norway. Energy obligations shall be based on an energy company with minimum credit rating of BBB+.

s: tax rate equal to the tax rate for network operators

Cost flows from the Skagerak Energi AS Investment Case

Case 1 – Investment

Scenario 1: Flexibility in case of malfunction

34 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	0.0007764	0.0010583	0.0014136	0.0018384	0.0023736	0.0030239	0.0037483	0.0045173	0.0054317
Change in VoLL costs	0.013586698	0.01852047	0.024737692	0.032171754	0.041538249	0.052918651	0.065594392	0.079052773	0.095055041
Change in investments	5640	0	0	0	0	0	0	0	0
Change in network loss costs	0	0	0	0	0	0	0	0	0
Sum	5640.014363	0.019578783	0.026151275	0.034010139	0.043911863	0.055942574	0.069342643	0.083570074	0.100486757
PV with 4 percent discount rate	4384	-1317.420065	-1381.730698	-1449.186584	-1519.942559	-1594.16181	-1672.015579	-1753.682666	-1839.350028

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0064118	0.0075192	0.0087520	0.0100230	0.0114378	0.0129842	0.0147916	0.0167518	0.0183755	0.0201482	0.0219269	0.0238089	0.0259521
0.112205938	0.131586593	0.153159885	0.175402443	0.200161479	0.227224363	0.258852775	0.29315637	0.321570478	0.352593185	0.383720684	0.416656315	0.4541611
0	0	0	0	0	0	0	0	0	0	0	0	-3422
0	0	0	0	0	0	0	0	0	0	0	0	0
0.118617706	0.139105827	0.161911879	0.18542544	0.211599278	0.240208612	0.273644362	0.309908162	0.339945934	0.372741367	0.405647581	0.440465247	-3421.519887
-1929.2157	-2023.485833	-2122.377836	-2226.119687	-2334.948802	-2449.116229	-2568.885032	-2694.533619	-2826.351892	-2964.634399	-3109.699489	-3261.878267	-3421.519887

16 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	0.0003321	0.0003936	0.0004654	0.0005448	0.0006284	0.0007267	0.0008241	0.0009252	0.0010388
Change in VoLL costs	0.005811293	0.006888184	0.008143805	0.009533922	0.010997765	0.012718067	0.014421051	0.016190988	0.018178351
Change in investments	5640	0	0	0	0	0	0	0	0
Change in network loss costs	0	0	0	0	0	0	0	0	0
Sum	5640.006143	0.007281795	0.008609165	0.010078718	0.011626208	0.013444813	0.015245111	0.017116187	0.019217114
PV with 4 percent discount rate	4382	-1319.231901	-1383.618055	-1451.147645	-1521.974221	-1596.258757	-1674.170285	-1755.885784	-1841.590962

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0011404	0.0012563	0.0013900	0.0015080	0.0016557	0.0017988	0.0019526	0.0021254	0.0022655	0.0024008	0.0025550	0.0027215	0.0028931
0.019956525	0.02198488	0.024324892	0.026390752	0.028974853	0.031478178	0.034170909	0.037193856	0.039646297	0.042014197	0.044712766	0.047625517	0.050628956
0	0	0	0	0	0	0	0	0	0	0	0	-3422
0	0	0	0	0	0	0	0	0	0	0	0	0
0.021096898	0.023241159	0.025714886	0.027898795	0.030630558	0.033276931	0.036123533	0.039319219	0.0419118	0.044415009	0.047267781	0.050346975	-3421.946478
-1931.480755	-2025.759143	-2124.640564	-2228.349994	-2337.122734	-2451.206448	-2570.860224	-2696.356089	-2827.979504	-2966.028861	-3110.817652	-3262.675128	-3421.946478

0 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186
Change in VoLL costs	0.002075138	0.002075138	0.002075138	0.002075138	0.002075138	0.002075138	0.002075138	0.002075138	0.002075138
Change in investments	5640	0	0	0	0	0	0	0	0
Change in network loss costs	0	0	0	0	0	0	0	0	0
Sum	5640.002194	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717
PV with 4 percent discount rate	4382	-1319.521951	-1383.916923	-1451.45437	-1522.287644	-1596.577582	-1674.492868	-1756.210421	-1841.915791

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186
0.002075138	0.002075138	0.002075138	0.002075138	0.002075138	0.002075138	0.002075138	0.002075138	0.002075138	0.002075138	0.002075138	0.002075138	0.002075138
0	0	0	0	0	0	0	0	0	0	0	0	-3422
0	0	0	0	0	0	0	0	0	0	0	0	0
0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	-3421.997806
-1931.803582	-2026.077897	-2124.9528	-2228.652797	-2337.413354	-2451.481427	-2571.116021	-2696.588784	-2828.184617	-2966.202327	-3110.955302	-3262.772221	-3421.997806

Scenario 2: Flexibility for peak loads and in case of malfunction

34 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	0.0007764	0.0010583	0.0014136	0.0018384	0.0023736	0.0030239	0.0037483	0.0045173	0.0054317
Change in VoLL costs	0.0135867	0.0185205	0.0247377	0.0321718	0.0415382	0.0529187	0.0655944	0.0790528	0.0950550
Change in investments	5640.0000000	0	0	0	0	0	0	0	0
Change in network loss costs	0	0	0	0	0	0	0	0	0
Sum	5640.0143631	0.0195788	0.0261513	0.0340101	0.0439119	0.0559426	0.0693426	0.0835701	0.1004868
PV with 4 percent discount rate	4384	-1317.420065	-1381.730698	-1449.186584	-1519.942559	-1594.16181	-1672.015579	-1753.682666	-1839.350028

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0064118	0.0075192	0.0087520	0.0100230	0.0114378	0.0129842	0.0147916	0.0167518	0.0183755	0.0201482	0.0219269	0.0238089	0.0259521
0.1122059	0.1315866	0.1531599	0.1754024	0.2001615	0.2272244	0.2588528	0.2931564	0.3215705	0.3525932	0.3837207	0.4166563	0.4541611
0	0	0	0	0	0	0	0	0	0	0	0	-3422.0000000
0	0	0	0	0	0	0	0	0	0	0	0	0
0.1186177	0.1391058	0.1619119	0.1854254	0.2115993	0.2402086	0.2736444	0.3099082	0.3399459	0.3727414	0.4056476	0.4404652	-3421.5198868
-1929.2157	-2023.485833	-2122.377836	-2226.119687	-2334.948802	-2449.116229	-2568.885032	-2694.533619	-2826.351892	-2964.634399	-3109.699489	-3261.878267	-3421.519887

16 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	0.0003321	0.0003936	0.0004654	0.0005448	0.0006284	0.0007267	0.0008241	0.0009252	0.0010388
Change in VoLL costs	0.0058113	0.0068882	0.0081438	0.0095339	0.0109978	0.0127181	0.0144211	0.0161910	0.0181784
Change in investments	5640.0000000	0	0	0	0	0	0	0	0
Change in network loss costs	0	0	0	0	0	0	0	0	0
Sum	5640.0061434	0.0072818	0.0086092	0.0100787	0.0116262	0.0134448	0.0152451	0.0171162	0.0192171
PV with 4 percent discount rate	4382	-1319.231901	-1383.618055	-1451.147645	-1521.974221	-1596.258757	-1674.170285	-1755.885784	-1841.590962

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0011404	0.0012563	0.0013900	0.0015080	0.0016557	0.0017988	0.0019526	0.0021254	0.0022655	0.0024008	0.0025550	0.0027215	0.0028931
0.0199565	0.0219849	0.0243249	0.0263908	0.0289749	0.0314782	0.0341709	0.0371939	0.0396463	0.0420142	0.0447128	0.0476255	0.0506290
0	0	0	0	0	0	0	0	0	0	0	0	-3422.0000000
0	0	0	0	0	0	0	0	0	0	0	0	0
0.0210969	0.0232412	0.0257149	0.0278988	0.0306306	0.0332769	0.0361235	0.0393192	0.0419118	0.0444150	0.0472678	0.0503470	-3421.9464780
-1931.480755	-2025.759143	-2124.640564	-2228.349994	-2337.122734	-2451.206448	-2570.860224	-2696.356089	-2827.979504	-2966.028861	-3110.817652	-3262.675128	-3421.946478

0 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186
Change in VoLL costs	0.0020751	0.0020751	0.0020751	0.0020751	0.0020751	0.0020751	0.0020751	0.0020751	0.0020751
Change in investments	5640.0000000	0	0	0	0	0	0	0	0
Change in network loss costs	0	0	0	0	0	0	0	0	0
Sum	5640.002194	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717
PV with 4 percent discount rate	4382	-1319.521951	-1383.916923	-1451.45437	-1522.287644	-1596.577582	-1674.492868	-1756.210421	-1841.915791

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186	0.0001186
0.0020751	0.0020751	0.0020751	0.0020751	0.0020751	0.0020751	0.0020751	0.0020751	0.0020751	0.0020751	0.0020751	0.0020751	0.0020751
0	0	0	0	0	0	0	0	0	0	0	0	-3422.0000000
0	0	0	0	0	0	0	0	0	0	0	0	0
0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	0.002193717	-3421.997806
-1931.803582	-2026.077897	-2124.9528	-2228.652797	-2337.413354	-2451.481427	-2571.116021	-2696.588784	-2828.184617	-2966.202327	-3110.955302	-3262.772221	-3421.997806

Case 2 – Compensation through tariff discount

Scenario 1: Flexibility in case of malfunction

Existing flexibility

34 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	25.0031644	0.0041271	0.0053016	12.5018384	0.0023736	0.0030239	0.0037483	0.0045173	0.0054317
Change in VoLL costs	0.454213372	0.532012749	0.621408083	0.032171754	0.041538249	0.052918651	0.065594392	0.079052773	0.095055041
Change in investments	0	0	0	5820	0	0	0	0	0
Change in network loss costs	133.9992945	133.9992945	133.9992945	0	0	0	0	0	0
Sum	159.4566723	134.5354344	134.6260042	5832.53401	0.043911863	0.055942574	0.069342643	0.083570074	0.100486757
PV with 4 percent discount rate	4079	4111.289636	4170.819806	4233.16006	-1677.423399	-1759.327716	-1845.241581	-1935.362097	-2029.895415

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0064118	0.0075192	0.0087520	0.0100230	0.0114378	0.0129842	0.0147916	0.0167518	0.0183755	0.0201482	0.0219269	0.0238089	0.0259521
0.112205938	0.131586593	0.153159885	0.175402443	0.200161479	0.227224363	0.258852775	0.29315637	0.321570478	0.352593185	0.383720684	0.416656315	0.4541611
0	0	0	0	0	0	0	0	0	0	0	0	-3776
0	0	0	0	0	0	0	0	0	0	0	0	0
0.118617706	0.139105827	0.161911879	0.18542544	0.211599278	0.240208612	0.273644362	0.309908162	0.339945934	0.372741367	0.405647581	0.440465247	-3775.519887
-2129.059702	-2233.082222	-2342.202529	-2456.671825	-2576.751884	-2702.719302	-2834.863934	-2973.492293	-3118.923748	-3271.483762	-3431.523101	-3599.406872	-3775.519887

16 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	25.0066744	0.0075424	0.0084579	0.0094020	25.0048467	0.0054223	0.0059703	0.0065264	0.0071168
Change in VoLL costs	0.800103014	0.856448699	0.917555465	0.975226044	0.665416093	0.711553589	0.753362043	0.792302402	0.62235602
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	67.88467438	67.88467438	67.88467438	67.88467438	106.1855578	106.1855578	106.1855578	106.1855578	106.1855578
Sum	93.69145175	68.74866544	68.81068774	68.86930247	131.8558205	106.9025337	106.9448901	106.9843866	106.8150306
PV with 4 percent discount rate	1828	1819.385369	1836.067775	1853.499233	1871.719871	1824.769416	1801.698786	1777.457886	1751.992607

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0077267	25.0045452	0.0049447	0.0053044	0.0057217	0.0061553	0.0066088	25.0043893	0.0046639	0.0049514	0.0052499	0.0055495	12.5028931
0.65379045	0.686096782	0.719843444	0.751720914	0.471638416	0.494666211	0.518814187	0.54419144	0.565248743	0.586687536	0.607706613	0.630283497	0.050628956
0	0	0	0	0	0	0	0	0	0	0	0	600
106.1855578	136.9630534	136.9630534	136.9630534	136.9630534	136.9630534	136.9630534	161.8130313	161.8130313	161.8130313	161.8130313	161.8130313	0
106.847075	162.6536953	137.6878416	137.7200787	137.4404135	137.4638749	137.4884763	187.361612	162.3829439	162.4046702	162.4259878	162.4488643	612.553522
1725.462242	1697.603587	1609.855446	1544.009384	1474.916223	1402.744629	1327.026455	1247.587432	1111.96484	995.9214928	874.1924435	746.5006588	612.553522

0 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	25.0130518	0.0130518	0.0130518	0.0130518	0.0130518	0.0130518	0.0130518	0.0130518	0.0130518
Change in VoLL costs	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312
Sum	57.15059805	32.15059805	32.15059805	32.15059805	32.15059805	32.15059805	32.15059805	32.15059805	32.15059805
PV with 4 percent discount rate	687	660.4774752	658.9892288	657.4283559	655.7913124	654.0743812	652.2736638	650.3850713	648.4043156

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0130518	0.0130518	0.0130518	0.0130518	0.0130518	0.0130518	0.0130518	0.0130518	0.0130518	0.0130518	0.0130518	0.0130518	12.5001186
1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	0.619482046	0.002075138
0	0	0	0	0	0	0	0	0	0	0	0	600
30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	0
32.15059805	32.15059805	32.15059805	32.15059805	32.15059805	32.15059805	32.15059805	32.15059805	32.15059805	32.15059805	32.15059805	31.56373381	612.5021937
646.326899	644.1481044	641.8629846	639.4663511	636.9527618	634.3165093	631.5516077	628.6517789	625.6104385	622.4206807	619.0752627	615.5665882	612.5021937

Existing flexibility + households

34 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	25.0016578	0.0022203	0.0029436	25.0019439	12.5023736	0.0030239	0.0037483	0.0045173	0.0054317
Change in VoLL costs	0.534668198	0.62205944	0.721634293	0.539030576	0.041538249	0.052918651	0.065594392	0.079052773	0.095055041
Change in investments	0	0	0	0	5880	0	0	0	0
Change in network loss costs	119.1805004	119.1805004	119.1805004	149.957996	0	0	0	0	0
Sum	144.7168264	119.8047801	119.9050783	175.4989704	5892.543912	0.055942574	0.069342643	0.083570074	0.100486757
PV with 4 percent discount rate	3960	4001.830328	4071.468395	4144.399607	4162.582987	-1814.383018	-1902.983582	-1995.921907	-2093.410544

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0064118	0.0075192	0.0087520	0.0100230	0.0114378	0.0129842	0.0147916	0.0167518	0.0183755	0.0201482	0.0219269	0.0238089	0.0259521
0.112205938	0.131586593	0.153159885	0.175402443	0.200161479	0.227224363	0.258852775	0.29315637	0.321570478	0.352593185	0.383720684	0.416656315	0.4541611
0	0	0	0	0	0	0	0	0	0	0	0	-3894
0	0	0	0	0	0	0	0	0	0	0	0	0
0.118617706	0.139105827	0.161911879	0.18542544	0.211599278	0.240208612	0.273644362	0.309908162	0.339945934	0.372741367	0.405647581	0.440465247	-3893.519887
-2195.674369	-2302.947685	-2415.477426	-2533.522538	-2657.352912	-2787.253659	-2923.523569	-3066.478517	-3216.4477	-3373.766883	-3538.797638	-3711.916406	-3893.519887

16 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	25.0025997	0.0029808	0.0034094	0.0038611	25.0018392	0.0021115	0.0023688	0.0026355	0.0029132
Change in VoLL costs	0.958356393	0.657683769	0.705871108	0.752841332	0.802115557	0.857099333	0.606781931	0.641307081	0.677766869
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	67.88467438	67.88467438	67.88467438	67.88467438	106.1855578	106.1855578	106.1855578	106.1855578	106.1855578
Sum	93.84563048	68.5453389	68.59395488	68.64137678	131.9895126	107.0447686	106.7947085	106.8295004	106.8662379
PV with 4 percent discount rate	1816	1805.968169	1822.209064	1839.191526	1856.952997	1809.141702	1785.159264	1760.268746	1734.12708

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0031888	25.0017640	0.0019490	0.0021275	0.0023239	0.0025351	0.0027636	0.0017421	0.0018661	0.0020002	0.0021459	0.0022931	12.5028931
0.711118338	0.745690394	0.377813451	0.396957602	0.417427539	0.438718044	0.460195851	0.48299781	0.501901071	0.520297255	0.540563945	0.560755677	0.050628956
0	0	0	0	0	0	0	0	0	0	0	0	600
106.1855578	136.9630534	136.9630534	136.9630534	136.9630534	136.9630534	136.9630534	161.8130313	161.8130313	161.8130313	161.8130313	161.8130313	0
106.8998649	162.7105078	137.3428158	137.3621385	137.3828048	137.4043065	137.4260128	162.2977712	162.3167984	162.3353288	162.3557412	162.3760801	612.553522
1706.671172	1677.840147	1589.067965	1522.569337	1452.805309	1379.615123	1302.830704	1222.27644	1111.705628	995.7190047	874.0527993	746.4278746	612.553522

0 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	25.0054056	0.0054056	0.0054056	0.0054056	0.0054056	0.0054056	0.0054056	0.0054056	0.0054056
Change in VoLL costs	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312
Sum	56.60421402	31.60421402	31.60421402	31.60421402	31.60421402	31.60421402	31.60421402	31.60421402	31.60421402
PV with 4 percent discount rate	680	653.5001535	652.2444613	650.9274914	649.5462533	648.0976108	646.5782745	644.9847947	643.313553

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0054056	0.0054056	0.0054056	0.0054056	0.0054056	0.0054056	0.0054056	0.0054056	0.0054056	0.0054056	0.0054056	0.0054056	12.5001186
0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.002075138
0	0	0	0	0	0	0	0	0	0	0	0	600
30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	0
31.60421402	31.60421402	31.60421402	31.60421402	31.60421402	31.60421402	31.60421402	31.60421402	31.60421402	31.60421402	31.60421402	31.60421402	612.5021937
641.5607547	639.7224199	637.7943743	635.7722401	633.6514258	631.4271157	629.0942593	626.6475595	624.0814607	621.3901363	618.5674753	615.6070684	612.5021937

Scenario 2: Flexibility for peak loads and in case of malfunction

Existing flexibility

34 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	25.0259550	0.0304007	0.0355087	12.5018384	0.0023736	0.0030239	0.0037483	0.0045173	0.0054317
Change in VoLL costs	0.4542134	0.5320127	0.6214081	0.0321718	0.0415382	0.0529187	0.0655944	0.0790528	0.0950550
Change in investments	0	0	0	5820.0000000	0	0	0	0	0
Change in network loss costs	34.9264800	34.9264800	34.9264800	0	0	0	0	0	0
Sum	60.40664842	35.48889348	35.58339679	5832.53401	0.043911863	0.055942574	0.069342643	0.083570074	0.100486757
PV with 4 percent discount rate	3796	3917.808877	4071.777199	4233.16006	-1677.423399	-1759.327716	-1845.241581	-1935.362097	-2029.895415

	10	11	12	13	14	15	16	17	18	19	20	21	22
Change in O&M costs	0.0064118	0.0075192	0.0087520	0.0100230	0.0114378	0.0129842	0.0147916	0.0167518	0.0183755	0.0201482	0.0219269	0.0238089	0.0259521
Change in VoLL costs	0.1122059	0.1315866	0.1531599	0.1754024	0.2001615	0.2272244	0.2588528	0.2931564	0.3215705	0.3525932	0.3837207	0.4166563	0.4541611
Change in investments	0	0	0	0	0	0	0	0	0	0	0	0	-3776.0000000
Change in network loss costs	0	0	0	0	0	0	0	0	0	0	0	0	0
Sum	0.118617706	0.139105827	0.161911879	0.18542544	0.211599278	0.240208612	0.273644362	0.309908162	0.339945934	0.372741367	0.405647581	0.440465247	-3775.519887
PV with 4 percent discount rate	-2129.059702	-2233.082222	-2342.202529	-2456.671825	-2576.751884	-2702.719302	-2834.863934	-2973.492293	-3118.923748	-3271.483762	-3431.523101	-3599.406872	-3775.519887

16 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	25.0457202	0.0489399	0.0524317	0.0557272	25.0380238	0.0406602	0.0430493	0.0452744	25.0355632
Change in VoLL costs	0.8001030	0.8564487	0.9175555	0.9752260	0.6654161	0.7115536	0.7533620	0.7923024	0.6223560
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	15.7878000	15.7878000	15.7878000	15.7878000	25.3249200	25.3249200	25.3249200	25.3249200	31.5756000
Sum	41.6336232	16.6931886	16.7577872	16.8187532	51.0283599	26.0771338	26.1213313	26.1624968	57.2335192
PV with 4 percent discount rate	712	703.2271424	720.0368107	737.5990398	755.9543646	739.3263937	748.0558238	757.1648958	766.675316

	10	11	12	13	14	15	16	17	18	19	20	21	22
Change in O&M costs	0.0373595	0.0392055	0.0411339	0.0429555	25.0269508	0.0282666	0.0296465	0.0310967	0.0322999	0.0335250	0.0347261	0.0360162	12.5028931
Change in VoLL costs	0.6537905	0.6860968	0.7198434	0.7517209	0.4716384	0.4946662	0.5188142	0.5441914	0.5652487	0.5866875	0.6077066	0.6302835	0.0506290
Change in investments	0	0	0	0	0	0	0	0	0	0	0	0	600.0000000
Change in network loss costs	31.5756000	31.5756000	31.5756000	31.5756000	45.0865295	45.0865295	45.0865295	45.0865295	45.0865295	45.0865295	45.0865295	45.0865295	0.0000000
Sum	32.2667499	32.3009023	32.3365774	32.3702764	70.5851187	45.6094624	45.6349902	45.6618176	45.6840782	45.7067420	45.7289622	45.7528292	612.5535220
PV with 4 percent discount rate	744.0625565	746.5314419	749.08499	751.7257351	754.4600051	717.2479809	704.4144783	690.9279271	676.7550956	661.8672831	646.2291755	629.8046237	612.553522

0 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	0.0689341	0.0689341	0.0689341	0.0689341	0.0689341	0.0689341	0.0689341	0.0689341	0.0689341
Change in VoLL costs	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	0	0	0	0	0	0	0	0	0
Sum	1.275280357	1.275280357	1.275280357	1.275280357	1.275280357	1.275280357	1.275280357	1.275280357	1.275280357
PV with 4 percent discount rate	238	247.9542408	258.7168937	270.0047641	281.8434825	294.2599304	307.282301	320.9401632	335.2645292

	10	11	12	13	14	15	16	17	18	19	20	21	22
Change in O&M costs	0.0689341	0.0689341	0.0689341	0.0689341	0.0689341	0.0689341	0.0689341	0.0689341	0.0689341	0.0689341	0.0689341	0.0353990	0.0001186
Change in VoLL costs	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	0.619482046	0.002075138
Change in investments	0	0	0	0	0	0	0	0	0	0	0	0	600
Change in network loss costs	0	0	0	0	0	0	0	0	0	0	0	0	0
Sum	1.275280357	1.275280357	1.275280357	1.275280357	1.275280357	1.275280357	1.275280357	1.275280357	1.275280357	1.275280357	1.275280357	0.654881021	600.0021937
PV with 4 percent discount rate	350.2879242	366.0444608	382.5699165	399.9018143	418.0795089	437.1442748	457.1394014	478.1102902	500.1045583	523.1721467	547.3654334	572.7393525	600.0021937

Existing flexibility + households

34 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	25.0305525	0.0355463	0.0412362	25.0308017	12.5023736	0.0030239	0.0037483	0.0045173	0.0054317
Change in VoLL costs	0.534668198	0.62205944	0.721634293	0.539030576	0.041538249	0.052918651	0.065594392	0.079052773	0.095055041
Change in investments	0	0	0	0	5880	0	0	0	0
Change in network loss costs	19.6542	19.6542	19.6542	28.6758	0	0	0	0	0
Sum	45.21942067	20.31180569	20.41707054	54.24563232	5892.543912	0.055942574	0.069342643	0.083570074	0.100486757
PV with 4 percent discount rate	3570	3697.246293	3856.36889	4023.146268	4162.582987	-1814.383018	-1902.983582	-1995.921907	-2093.410544

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0064118	0.0075192	0.0087520	0.0100230	0.0114378	0.0129842	0.0147916	0.0167518	0.0183755	0.0201482	0.0219269	0.0238089	0.0259521
0.112205938	0.131586593	0.153159885	0.175402443	0.200161479	0.227224363	0.258852775	0.29315637	0.321570478	0.352593185	0.383720684	0.416656315	0.4541611
0	0	0	0	0	0	0	0	0	0	0	0	-3894
0	0	0	0	0	0	0	0	0	0	0	0	0
0.118617706	0.139105827	0.161911879	0.18542544	0.211599278	0.240208612	0.273644362	0.309908162	0.339945934	0.372741367	0.405647581	0.440465247	-3893.519887
-2195.674369	-2302.947685	-2415.477426	-2533.522538	-2657.352912	-2787.253659	-2923.523569	-3066.478517	-3216.4477	-3373.766883	-3538.797638	-3711.916406	-3893.519887

16 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	0.0547632	25.0375819	0.0403355	0.0430195	0.0458352	0.0489771	25.0346733	0.0366461	0.0387295
Change in VoLL costs	0.958356393	0.657683769	0.705871108	0.752841332	0.802115557	0.857099333	0.606781931	0.641307081	0.677766869
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	0	9.27936	9.27936	9.27936	9.27936	9.27936	17.721	17.721	17.721
Sum	1.013119616	34.9746257	10.0255666	10.07522084	10.12731073	10.18543644	43.36245518	18.3989532	18.4374964
PV with 4 percent discount rate	550	575.5768229	566.9835845	584.1375691	602.0765909	620.836405	640.4507359	626.2261888	637.4892047

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0406353	0.0426109	25.0215893	0.0226833	0.0238530	0.0250696	0.0262969	0.0275999	0.0286801	0.0297313	0.0308894	0.0320432	12.5028931
0.711118338	0.745690394	0.377813451	0.396957602	0.417427539	0.438718044	0.460195851	0.48299781	0.501901071	0.520297255	0.540563945	0.560755677	0.050628956
0	0	0	0	0	0	0	0	0	0	0	0	600
17.721	17.721	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	0
18.47275367	18.50930127	57.94160279	32.96184089	32.98348054	33.00598765	33.02869276	33.05279769	33.07278113	33.09222853	33.11365331	33.13499886	612.553522
649.2614316	661.5711654	674.4432831	646.5869623	643.5700274	640.3831703	637.0171892	633.463135	629.7103618	625.7534946	621.5831359	617.1867933	612.553522

0 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	0.0381491	25.0381491	0.0381491	0.0381491	0.0381491	0.0381491	25.0381491	0.0381491	0.0381491
Change in VoLL costs	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	0	0	0	0	0	0	0	0	0
Sum	0.705757474	25.70575747	0.705757474	0.705757474	0.705757474	0.705757474	25.70575747	0.705757474	0.705757474
PV with 4 percent discount rate	292	305.7298656	293.6892846	307.2811232	321.5362436	336.4870139	352.1673817	342.3929515	358.3615291

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0381491	0.0381491	25.0381491	0.0381491	0.0381491	0.0381491	0.0381491	0.0381491	0.0381491	0.0381491	0.0381491	0.0381491	12.5001186
0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.002075138
0	0	0	0	0	0	0	0	0	0	0	0	600
0	0	0	0	0	0	0	0	0	0	0	0	0
0.705757474	0.705757474	25.70575747	0.705757474	0.705757474	0.705757474	0.705757474	0.705757474	0.705757474	0.705757474	0.705757474	0.705757474	612.5021937
375.1093733	392.6745123	411.09683	404.1981569	423.1828285	443.0939521	463.9767385	485.8786049	508.8492824	532.9409289	558.2082478	584.7086119	612.5021937

Case 3 – Compensation through availability and activation

Scenario 1: Flexibility in case of malfunction

Existing flexibility

34 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	92.1959350	67.2668087	67.3485304	12.5018384	0.0023736	0.0030239	0.0037483	0.0045173	0.0054317
Change in VoLL costs	0.454213372	0.532012749	0.621408083	0.032171754	0.041538249	0.052918651	0.065594392	0.079052773	0.095055041
Change in investments	0	0	0	5820	0	0	0	0	0
Change in network loss costs	133.9992945	133.9992945	133.9992945	0	0	0	0	0	0
Sum	226.6494429	201.798116	201.969233	5832.53401	0.043911863	0.055942574	0.069342643	0.083570074	0.100486757
PV with 4 percent discount rate	4272	4242.762108	4238.163035	4233.16006	-1677.423399	-1759.327716	-1845.241581	-1935.362097	-2029.895415

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0064118	0.0075192	0.0087520	0.0100230	0.0114378	0.0129842	0.0147916	0.0167518	0.0183755	0.0201482	0.0219269	0.0238089	0.0259521
0.112205938	0.131586593	0.153159885	0.175402443	0.200161479	0.227224363	0.258852775	0.29315637	0.321570478	0.352593185	0.383720684	0.416656315	0.4541611
0	0	0	0	0	0	0	0	0	0	0	0	-3776
0	0	0	0	0	0	0	0	0	0	0	0	0
0.118617706	0.139105827	0.161911879	0.18542544	0.211599278	0.240208612	0.273644362	0.309908162	0.339945934	0.372741367	0.405647581	0.440465247	-3775.519887
-2129.059702	-2233.082222	-2342.202529	-2456.671825	-2576.751884	-2702.719302	-2834.863934	-2973.492293	-3118.923748	-3271.483762	-3431.523101	-3599.406872	-3775.519887

16 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	92.4990667	67.5545958	67.6161203	67.6731722	92.3367400	67.3763076	67.4154964	67.4517221	67.4893017
Change in VoLL costs	0.800103014	0.856448699	0.917555465	0.975226044	0.665416093	0.711553589	0.753362043	0.792302402	0.62235602
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	67.88467438	67.88467438	67.88467438	67.88467438	106.1855578	106.1855578	106.1855578	106.1855578	106.1855578
Sum	161.1838441	136.2957189	136.4183502	136.5330727	199.1877138	174.2734189	174.3544162	174.4295823	174.2972155
PV with 4 percent discount rate	2745	2709.656193	2698.940465	2687.573194	2675.53088	2597.188712	2541.15356	2482.298942	2420.493384

10	11	12	13	14	15	16	17	18	19	20	21	22
67.5261251	92.2947625	67.3222853	67.3470707	67.3746906	67.4028505	67.4321843	92.2679898	67.2867759	67.3069166	67.3247960	67.3444880	12.5028931
0.65379045	0.686096782	0.719843444	0.751720914	0.471638416	0.494666211	0.518814187	0.54419144	0.565248743	0.586687536	0.607706613	0.630283497	0.050628956
0	0	0	0	0	0	0	0	0	0	0	0	600
106.1855578	136.9630534	136.9630534	136.9630534	136.9630534	136.9630534	136.9630534	161.8130313	161.8130313	161.8130313	161.8130313	161.8130313	0
174.3654734	229.9439126	205.0051821	205.061845	204.8093824	204.8605701	204.9140519	254.6252125	229.6650559	229.7066355	229.7455339	229.7878028	612.553522
2355.810542	2287.899588	2158.383912	2048.703612	1933.611485	1813.167645	1686.79246	1554.194075	1362.987823	1188.628918	1005.71769	813.8395972	612.553522

0 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	92.9853201	67.9853201	67.9853201	67.9853201	67.9853201	67.9853201	67.9853201	67.9853201	67.9853201
Change in VoLL costs	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312
Sum	125.1228664	100.1228664	100.1228664	100.1228664	100.1228664	100.1228664	100.1228664	100.1228664	100.1228664
PV with 4 percent discount rate	1611	1558.009444	1529.031443	1498.639315	1466.764051	1433.333275	1398.271076	1361.497843	1322.930075

10	11	12	13	14	15	16	17	18	19	20	21	22
67.9853201	67.9853201	67.9853201	67.9853201	67.9853201	67.9853201	67.9853201	67.9853201	67.9853201	67.9853201	67.9853201	67.9853201	12.5001186
1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	0.619482046	0.002075138
0	0	0	0	0	0	0	0	0	0	0	0	600
30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	0
100.1228664	100.1228664	100.1228664	100.1228664	100.1228664	100.1228664	100.1228664	100.1228664	100.1228664	100.1228664	100.1228664	99.53600216	612.5021937
1282.480201	1240.056372	1195.562261	1148.896837	1099.95414	1048.62304	994.786982	938.3237245	879.1050599	816.9965246	751.8570927	683.5388566	612.5021937

Existing flexibility + households

34 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	118.1003390	93.3288131	93.5948950	118.1576186	12.5023736	0.0030239	0.0037483	0.0045173	0.0054317
Change in VoLL costs	0.534668198	0.62205944	0.721634293	0.539030576	0.041538249	0.052918651	0.065594392	0.079052773	0.095055041
Change in investments	0	0	0	0	5880	0	0	0	0
Change in network loss costs	119.1805004	119.1805004	119.1805004	149.957996	0	0	0	0	0
Sum	237.8155076	213.131373	213.4970296	268.6546451	5892.543912	0.055942574	0.069342643	0.083570074	0.100486757
PV with 4 percent discount rate	4308	4269.082504	4253.881546	4237.555281	4162.582987	-1814.383018	-1902.983582	-1995.921907	-2093.410544

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0064118	0.0075192	0.0087520	0.0100230	0.0114378	0.0129842	0.0147916	0.0167518	0.0183755	0.0201482	0.0219269	0.0238089	0.0259521
0.112205938	0.131586593	0.153159885	0.175402443	0.200161479	0.227224363	0.258852775	0.29315637	0.321570478	0.352593185	0.383720684	0.416656315	0.4541611
0	0	0	0	0	0	0	0	0	0	0	0	-3894
0	0	0	0	0	0	0	0	0	0	0	0	0
0.118617706	0.139105827	0.161911879	0.18542544	0.211599278	0.240208612	0.273644362	0.309908162	0.339945934	0.372741367	0.405647581	0.440465247	-3893.519887
-2195.674369	-2302.947685	-2415.477426	-2533.522538	-2657.352912	-2787.253659	-2923.523569	-3066.478517	-3216.4477	-3373.766883	-3538.797638	-3711.916406	-3893.519887

16 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	117.0674497	92.0678308	92.0682594	92.0687111	117.0666892	92.0669615	92.0672188	92.0674855	92.0677632
Change in VoLL costs	0.958356393	0.657683769	0.705871108	0.752841332	0.802115557	0.857099333	0.606781931	0.641307081	0.677766869
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	67.88467438	67.88467438	67.88467438	67.88467438	106.1855578	106.1855578	106.1855578	106.1855578	106.1855578
Sum	185.9104805	160.6101889	160.6588049	160.7062268	224.0543626	199.1096186	198.8595585	198.8943504	198.9310879
PV with 4 percent discount rate	3067	3021.627851	3000.635324	2978.567373	2955.37277	2864.606746	2795.573387	2723.433463	2647.736621

10	11	12	13	14	15	16	17	18	19	20	21	22
92.0680388	117.0666140	92.0667990	92.0669775	92.0671739	92.0673851	92.0676136	92.0665921	92.0667161	92.0668502	92.0669959	92.0671431	12.5028931
0.711118338	0.745690394	0.377813451	0.396957602	0.417427539	0.438718044	0.460195851	0.48299781	0.501901071	0.520297255	0.540563945	0.560755677	0.050628956
0	0	0	0	0	0	0	0	0	0	0	0	600
106.1855578	136.9630534	136.9630534	136.9630534	136.9630534	136.9630534	136.9630534	161.8130313	161.8130313	161.8130313	161.8130313	161.8130313	0
198.9647149	254.7753578	229.4076658	229.4269885	229.4476548	229.4691565	229.4908628	254.3626212	254.3816484	254.4001788	254.4205912	254.4409301	612.553522
2568.307244	2484.966444	2339.024411	2212.566043	2079.91624	1940.771452	1794.813848	1641.710747	1455.050714	1259.261716	1053.89878	838.4927246	612.553522

0 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	119.8954551	94.8954551	94.8954551	94.8954551	94.8954551	94.8954551	94.8954551	94.8954551	94.8954551
Change in VoLL costs	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312
Sum	151.4942636	126.4942636	126.4942636	126.4942636	126.4942636	126.4942636	126.4942636	126.4942636	126.4942636
PV with 4 percent discount rate	1969	1906.464857	1866.833158	1825.267433	1781.6733	1735.951773	1687.999036	1637.706205	1584.959084

10	11	12	13	14	15	16	17	18	19	20	21	22
94.8954551	94.8954551	94.8954551	94.8954551	94.8954551	94.8954551	94.8954551	94.8954551	94.8954551	94.8954551	94.8954551	94.8954551	12.5001186
0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.002075138
0	0	0	0	0	0	0	0	0	0	0	0	600
30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	0
126.4942636	126.4942636	126.4942636	126.4942636	126.4942636	126.4942636	126.4942636	126.4942636	126.4942636	126.4942636	126.4942636	126.4942636	612.5021937
1529.637904	1471.61705	1410.764779	1346.942916	1280.006547	1209.803683	1136.174919	1058.953071	977.9627975	893.0201984	803.9324005	710.497118	612.5021937

Scenario 2: Flexibility for peak loads and in case of malfunction

Existing flexibility

34 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	123.4196565	114.6770092	136.3542229	12.5018384	0.0023736	0.0030239	0.0037483	0.0045173	0.0054317
Change in VoLL costs	0.4542134	0.5320127	0.6214081	0.0321718	0.0415382	0.0529187	0.0655944	0.0790528	0.0950550
Change in investments	0	0	0	5820.0000000	0	0	0	0	0
Change in network loss costs	34.9264800	34.9264800	34.9264800	0	0	0	0	0	0
Sum	158.8003499	150.1355019	171.902111	5832.53401	0.043911863	0.055942574	0.069342643	0.083570074	0.100486757
PV with 4 percent discount rate	4128	4162.431376	4208.095913	4233.16006	-1677.423399	-1759.327716	-1845.241581	-1935.362097	-2029.895415

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0064118	0.0075192	0.0087520	0.0100230	0.0114378	0.0129842	0.0147916	0.0167518	0.0183755	0.0201482	0.0219269	0.0238089	0.0259521
0.1122059	0.1315866	0.1531599	0.1754024	0.2001615	0.2272244	0.2588528	0.2931564	0.3215705	0.3525932	0.3837207	0.4166563	0.4541611
0	0	0	0	0	0	0	0	0	0	0	0	-3776.0000000
0	0	0	0	0	0	0	0	0	0	0	0	0
0.118617706	0.139105827	0.161911879	0.18542544	0.211599278	0.240208612	0.273644362	0.309908162	0.339945934	0.372741367	0.405647581	0.440465247	-3775.519887
-2129.059702	-2233.082222	-2342.202529	-2456.671825	-2576.751884	-2702.719302	-2834.863934	-2973.492293	-3118.923748	-3271.483762	-3431.523101	-3599.406872	-3775.519887

16 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	159.5307662	147.2376367	162.1635093	178.5435568	151.5544853	137.0758427	147.4865934	158.2069416	154.5826956
Change in VoLL costs	0.800103014	0.856448699	0.917555465	0.975226044	0.665416093	0.711553589	0.753362043	0.792302402	0.62235602
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	15.7878	15.7878	15.7878	15.7878	25.32492	25.32492	25.32492	25.32492	31.5756
Sum	176.1186692	163.8818853	178.8688648	195.3065829	177.5448214	163.1123163	173.5648754	184.324164	186.7806516
PV with 4 percent discount rate	2666	2611.62529	2567.193283	2504.87465	2422.274988	2354.272999	2298.089324	2228.201242	2143.618279

10	11	12	13	14	15	16	17	18	19	20	21	22
137.3127676	145.9101450	155.5516115	165.3630022	137.4213660	118.5074250	125.0102517	131.7294014	137.2311379	143.2427790	149.6837112	156.7961530	12.5028931
0.65379045	0.686096782	0.719843444	0.751720914	0.471638416	0.494666211	0.518814187	0.54419144	0.565248743	0.586687536	0.607706613	0.630283497	0.050628956
0	0	0	0	0	0	0	0	0	0	0	0	600
31.5756	31.5756	31.5756	31.5756	45.0865295	45.0865295	45.0865295	45.0865295	45.0865295	45.0865295	45.0865295	45.0865295	0
169.5421581	178.1718418	187.8470549	197.6903231	182.979534	164.0886207	170.6155954	177.3601223	182.8829161	188.915996	195.3779473	202.512966	612.553522
2052.331304	1974.669256	1884.166488	1779.099822	1658.582282	1547.612162	1451.03949	1342.908581	1222.427223	1090.274069	945.3443474	786.5647605	612.553522

0 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	173.2102963	173.2102963	173.2102963	173.2102963	173.2102963	173.2102963	173.2102963	173.2102963	173.2102963
Change in VoLL costs	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	0	0	0	0	0	0	0	0	0
Sum	174.4166425	174.4166425	174.4166425	174.4166425	174.4166425	174.4166425	174.4166425	174.4166425	174.4166425
PV with 4 percent discount rate	2591	2534.179367	2474.919145	2412.767025	2347.581881	2279.215702	2207.513254	2132.311726	2053.440363

10	11	12	13	14	15	16	17	18	19	20	21	22
173.2102963	173.2102963	173.2102963	173.2102963	173.2102963	173.2102963	173.2102963	173.2102963	173.2102963	173.2102963	173.2102963	173.1767612	0.0001186
1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	0.619482046	0.002075138
0	0	0	0	0	0	0	0	0	0	0	0	600
0	0	0	0	0	0	0	0	0	0	0	0	0
174.4166425	174.4166425	174.4166425	174.4166425	174.4166425	174.4166425	174.4166425	174.4166425	174.4166425	174.4166425	174.4166425	173.7962432	600.0021937
1970.720078	1883.963043	1792.972265	1697.541137	1597.45297	1492.4805	1382.385374	1266.917605	1145.81501	1018.802607	885.5919998	745.8807147	600.0021937

Existing flexibility + households

34 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	243.0910769	275.7494660	370.3600694	289.7747611	12.5023736	0.0030239	0.0037483	0.0045173	0.0054317
Change in VoLL costs	0.5346682	0.6220594	0.7216343	0.5390306	0.0415382	0.0529187	0.0655944	0.0790528	0.0950550
Change in investments	0	0	0	0	5880.0000000	0	0	0	0
Change in network loss costs	19.6542000	19.6542000	19.6542000	28.6758000	0	0	0	0	0
Sum	263.2799451	296.0257254	390.7359037	318.9895917	5892.543912	0.055942574	0.069342643	0.083570074	0.100486757
PV with 4 percent discount rate	4618	4566.728732	4479.113314	4287.890228	4162.582987	-1814.383018	-1902.983582	-1995.921907	-2093.410544

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0064118	0.0075192	0.0087520	0.0100230	0.0114378	0.0129842	0.0147916	0.0167518	0.0183755	0.0201482	0.0219269	0.0238089	0.0259521
0.1122059	0.1315866	0.1531599	0.1754024	0.2001615	0.2272244	0.2588528	0.2931564	0.3215705	0.3525932	0.3837207	0.4166563	0.4541611
0	0	0	0	0	0	0	0	0	0	0	0	-3894.0000000
0	0	0	0	0	0	0	0	0	0	0	0	0
0.118617706	0.139105827	0.161911879	0.18542544	0.211599278	0.240208612	0.273644362	0.309908162	0.339945934	0.372741367	0.405647581	0.440465247	-3893.519887
-2195.674369	-2302.947685	-2415.477426	-2533.522538	-2657.352912	-2787.253659	-2923.523569	-3066.478517	-3216.4477	-3373.766883	-3538.797638	-3711.916406	-3893.519887

16 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	380.0769367	264.4251605	268.1565044	302.4236846	345.8437011	396.1955388	277.9278544	277.3359395	307.1824058
Change in VoLL costs	0.958356393	0.657683769	0.705871108	0.752841332	0.802115557	0.857099333	0.606781931	0.641307081	0.677766869
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	0	9.27936	9.27936	9.27936	9.27936	9.27936	17.721	17.721	17.721
Sum	381.0352931	274.3622043	278.1417355	312.4558859	355.9251767	406.3319981	296.2556364	295.6982466	325.5811727
PV with 4 percent discount rate	4431	4247.959575	4167.508923	4079.168306	3950.527986	3770.019426	3527.835375	3389.28083	3244.549413

10	11	12	13	14	15	16	17	18	19	20	21	22
339.5107438	375.9636198	203.1254750	187.1282345	197.7168744	209.9404194	224.3540886	241.0407762	256.2590849	272.8333756	292.3210526	314.0812487	12.5028931
0.711118338	0.745690394	0.377813451	0.396957602	0.417427539	0.438718044	0.460195851	0.48299781	0.501901071	0.520297255	0.540563945	0.560755677	0.050628956
0	0	0	0	0	0	0	0	0	0	0	0	600
17.721	17.721	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	0
357.9428622	394.4303102	236.0454885	220.0673921	230.676502	242.9213374	257.3564844	274.065974	289.303186	305.8958728	325.4038166	347.1842044	612.553522
3061.41389	2835.400414	2560.089445	2437.457302	2325.598538	2197.154231	2049.599459	1879.704431	1683.993614	1462.751321	1213.309994	931.2359989	612.553522

0 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	205.1172625	230.1172625	205.1172625	205.1172625	205.1172625	205.1172625	230.1172625	205.1172625	205.1172625
Change in VoLL costs	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	0	0	0	0	0	0	0	0	0
Sum	205.784871	230.784871	205.784871	205.784871	205.784871	205.784871	230.784871	205.784871	205.784871
PV with 4 percent discount rate	3079	3013.673341	2918.693428	2845.298494	2768.321888	2687.588823	2602.915985	2487.891113	2393.473026

10	11	12	13	14	15	16	17	18	19	20	21	22
205.1172625	205.1172625	230.1172625	205.1172625	205.1172625	205.1172625	205.1172625	205.1172625	205.1172625	205.1172625	205.1172625	205.1172625	12.5001186
0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.002075138
0	0	0	0	0	0	0	0	0	0	0	0	600
0	0	0	0	0	0	0	0	0	0	0	0	0
205.784871	205.784871	230.784871	205.784871	205.784871	205.784871	205.784871	205.784871	205.784871	205.784871	205.784871	205.784871	612.5021937
2294.447337	2190.589195	2081.662775	1941.200746	1820.104169	1693.09808	1559.894094	1420.189753	1273.66784	1119.995658	958.8242735	789.7877254	612.5021937

Case 4 – Compensation through activation

Scenario 1: Flexibility in case of malfunction

Existing flexibility

34 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
Change in O&M costs	25.4957202	0.6015495	0.7235448	12.5018384	0.0023736	0.0030239	0.0037483	0.0045173	0.0054317	0.0064118	0.0075192	0.0087520	0.0100230	0.0114378	0.0129842	0.0147916	0.0167518	0.0183755	0.0201482	0.0219269	0.0238089	0.0259521
Change in VoLL costs	0.454213372	0.532012749	0.621408083	0.032171754	0.041538249	0.052918651	0.065594392	0.079052773	0.095055041	0.112205938	0.131586593	0.153159885	0.175402443	0.200161479	0.227224363	0.258852775	0.29315637	0.321570478	0.352593185	0.383720684	0.416656315	0.4541611
Change in investments	0	0	0	5820	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-3776
Change in network loss costs	133.9992945	133.9992945	133.9992945	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sum	159.9492282	135.1328568	135.3442474	5832.53401	0.043911863	0.055942574	0.069342643	0.083570074	0.100486757	0.118617706	0.139105827	0.161911879	0.18542544	0.211599278	0.240208612	0.273644362	0.309908162	0.339945934	0.372741367	0.405647581	0.440465247	-3775.519887
PV with 4 percent discount rate	4081	4112.571882	4171.538049	4233.16006	-1677.423399	-1759.327716	-1845.241581	-1935.362097	-2029.895415	-2129.059702	-2233.082222	-2342.202529	-2456.671825	-2576.751884	-2702.719302	-2834.863934	-2973.492293	-3118.923748	-3271.483762	-3431.523101	-3599.406872	-3775.519887

16 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
Change in O&M costs	25.9486629	1.0315226	1.1233516	1.2084573	25.7060866	0.7651502	0.8236595	0.8777199	0.9337941	0.9887243	25.6432711	0.6843555	0.7213539	0.7625751	0.8045981	0.8483721	25.6031900	0.6312318	0.6612993	0.6879690	0.7173572	12.5028931
Change in VoLL costs	0.8001030	0.8564487	0.9175555	0.9752260	0.6654161	0.7115536	0.7533620	0.7923024	0.6223560	0.6537905	0.6860968	0.7198434	0.7517209	0.4716384	0.4946662	0.5188142	0.5441914	0.5652487	0.5866875	0.6077066	0.6302835	0.0506290
Change in investments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600.0000000
Change in network loss costs	67.8846744	67.8846744	67.8846744	67.8846744	106.1855578	106.1855578	106.1855578	106.1855578	106.1855578	106.1855578	136.9630534	136.9630534	136.9630534	136.9630534	136.9630534	136.9630534	161.8130313	161.8130313	161.8130313	161.8130313	161.8130313	0.0000000
Sum	94.6334403	69.7726456	69.9255814	70.0683578	132.5570605	107.6622615	107.7625793	107.8555801	107.7417079	107.8280725	163.2924213	138.3672524	138.4361282	138.1972669	138.2623177	138.3302397	187.9604128	163.0095119	163.0610181	163.1087069	163.1606720	612.5535220
PV with 4 percent discount rate	1840	1830.436731	1846.584492	1863.359866	1880.804134	1833.56153	1810.123153	1785.43577	1759.446103	1732.30757	1703.754096	1615.636205	1549.359677	1479.776618	1407.048424	1330.702868	1250.560413	1114.45488	997.8759022	875.5538504	747.2124665	612.553522

0 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
Change in O&M costs	26.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	1.6748543	12.5001186
Change in VoLL costs	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	0.619482046	0.002075138
Change in investments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600
Change in network loss costs	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	0
Sum	58.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.81240056	33.22553633	612.5021937
PV with 4 percent discount rate	709	682.4205546	680.260232	677.9944856	675.6181707	673.1258918	670.5119896	667.770529	664.8952851	661.8797293	658.7170143	655.3999589	651.9210312	648.2723318	644.4455759	640.4320743	636.2227138	631.8079365	627.1777181	622.3215451	617.2283907	612.5021937

Existing flexibility + households

34 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	26.5524046	1.8948346	2.2935957	26.6381809	12.5023736	0.0030239	0.0037483	0.0045173	0.0054317
Change in VoLL costs	0.534668198	0.62205944	0.721634293	0.539030576	0.041538249	0.052918651	0.065594392	0.079052773	0.095055041
Change in investments	0	0	0	0	5880	0	0	0	0
Change in network loss costs	119.1805004	119.1805004	119.1805004	149.957996	0	0	0	0	0
Sum	146.2675732	121.6973944	122.1957303	177.1352074	5892.543912	0.055942574	0.069342643	0.083570074	0.100486757
PV with 4 percent discount rate	3967	4007.394525	4075.319151	4146.035844	4162.582987	-1814.383018	-1902.983582	-1995.921907	-2093.410544

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0064118	0.0075192	0.0087520	0.0100230	0.0114378	0.0129842	0.0147916	0.0167518	0.0183755	0.0201482	0.0219269	0.0238089	0.0259521
0.112205938	0.131586593	0.153159885	0.175402443	0.200161479	0.227224363	0.258852775	0.29315637	0.321570478	0.352593185	0.383720684	0.416656315	0.4541611
0	0	0	0	0	0	0	0	0	0	0	0	-3894
0	0	0	0	0	0	0	0	0	0	0	0	0
0.118617706	0.139105827	0.161911879	0.18542544	0.211599278	0.240208612	0.273644362	0.309908162	0.339945934	0.372741367	0.405647581	0.440465247	-3893.519887
-2195.674369	-2302.947685	-2415.477426	-2533.522538	-2657.352912	-2787.253659	-2923.523569	-3066.478517	-3216.4477	-3373.766883	-3538.797638	-3711.916406	-3893.519887

16 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	25.0025997	0.0029808	0.0034094	0.0038611	25.0018392	0.0021115	0.0023688	0.0026355	0.0029132
Change in VoLL costs	0.958356393	0.657683769	0.705871108	0.752841332	0.802115557	0.857099333	0.606781931	0.641307081	0.677766869
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	67.88467438	67.88467438	67.88467438	67.88467438	106.1855578	106.1855578	106.1855578	106.1855578	106.1855578
Sum	93.84563048	68.5453389	68.59395488	68.64137678	131.9895126	107.0447686	106.7947085	106.8295004	106.8662379
PV with 4 percent discount rate	1816	1805.968169	1822.209064	1839.191526	1856.952997	1809.141702	1785.159264	1760.268746	1734.12708

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0031888	25.0017640	0.0019490	0.0021275	0.0023239	0.0025351	0.0027636	0.0017421	0.0018661	0.0020002	0.0021459	0.0022931	12.5028931
0.711118338	0.745690394	0.377813451	0.396957602	0.417427539	0.438718044	0.460195851	0.48299781	0.501901071	0.520297255	0.540563945	0.560755677	0.050628956
0	0	0	0	0	0	0	0	0	0	0	0	600
106.1855578	136.9630534	136.9630534	136.9630534	136.9630534	136.9630534	136.9630534	161.8130313	161.8130313	161.8130313	161.8130313	161.8130313	0
106.8998649	162.7105078	137.3428158	137.3621385	137.3828048	137.4043065	137.4260128	162.2977712	162.3167984	162.3353288	162.3557412	162.3760801	612.553522
1706.671172	1677.840147	1589.067965	1522.569337	1452.805309	1379.615123	1302.830704	1222.27644	1111.705628	995.7190047	874.0527993	746.4278746	612.553522

0 percent load increase prediction

Flexibility in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	29.2432049	4.2432049	4.2432049	4.2432049	4.2432049	4.2432049	4.2432049	4.2432049	4.2432049
Change in VoLL costs	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312
Sum	60.84201335	35.84201335	35.84201335	35.84201335	35.84201335	35.84201335	35.84201335	35.84201335	35.84201335
PV with 4 percent discount rate	737	709.4576854	706.4881169	703.3736334	700.1071631	696.6812891	693.0882324	689.3198345	685.3675388

10	11	12	13	14	15	16	17	18	19	20	21	22
4.2432049	4.2432049	4.2432049	4.2432049	4.2432049	4.2432049	4.2432049	4.2432049	4.2432049	4.2432049	4.2432049	4.2432049	12.5001186
0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.002075138
0	0	0	0	0	0	0	0	0	0	0	0	600
30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	30.9312	0
35.84201335	35.84201335	35.84201335	35.84201335	35.84201335	35.84201335	35.84201335	35.84201335	35.84201335	35.84201335	35.84201335	35.84201335	612.5021937
681.2223711	676.8749193	672.3153117	667.5331953	662.5177117	657.2574724	651.7405334	645.9543679	639.8858374	633.5211627	626.8458918	619.8448678	612.5021937

Scenario 2: Flexibility for peak loads and in case of malfunction

Existing flexibility

34 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	72.3199073	71.7037134	104.2169800	12.5018384	0.0023736	0.0030239	0.0037483	0.0045173	0.0054317
Change in VoLL costs	0.454213372	0.532012749	0.621408083	0.032171754	0.041538249	0.052918651	0.065594392	0.079052773	0.095055041
Change in investments	0	0	0	5820	0	0	0	0	0
Change in network loss costs	34.92648	34.92648	34.92648	0	0	0	0	0	0
Sum	107.7006006	107.1622061	139.7648681	5832.53401	0.043911863	0.055942574	0.069342643	0.083570074	0.100486757
PV with 4 percent discount rate	4006	4088.816163	4175.95867	4233.16006	-1677.423399	-1759.327716	-1845.241581	-1935.362097	-2029.895415

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0064118	0.0075192	0.0087520	0.0100230	0.0114378	0.0129842	0.0147916	0.0167518	0.0183755	0.0201482	0.0219269	0.0238089	0.0259521
0.112205938	0.131586593	0.153159885	0.175402443	0.200161479	0.227224363	0.258852775	0.29315637	0.321570478	0.352593185	0.383720684	0.416656315	0.4541611
0	0	0	0	0	0	0	0	0	0	0	0	-3776
0	0	0	0	0	0	0	0	0	0	0	0	0
0.118617706	0.139105827	0.161911879	0.18542544	0.211599278	0.240208612	0.273644362	0.309908162	0.339945934	0.372741367	0.405647581	0.440465247	-3775.519887
-2129.059702	-2233.082222	-2342.202529	-2456.671825	-2576.751884	-2702.719302	-2834.863934	-2973.492293	-3118.923748	-3271.483762	-3431.523101	-3599.406872	-3775.519887

16 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	126.4766892	120.5353850	142.9224481	167.4908716	114.5161161	105.2968340	120.9117655	136.9911752	119.0596618
Change in VoLL costs	0.8001030	0.8564487	0.9175555	0.9752260	0.6654161	0.7115536	0.7533620	0.7923024	0.6223560
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	15.7878000	15.7878000	15.7878000	15.7878000	25.3249200	25.3249200	25.3249200	25.3249200	31.5756000
Sum	143.0645923	137.1796337	159.6278036	184.2538977	140.5064522	131.3333076	146.9900475	163.1083976	151.2576178
PV with 4 percent discount rate	2280	2241.469489	2206.979201	2147.262145	2058.80305	2011.909472	1972.348281	1914.435715	1836.792091

10	11	12	13	14	15	16	17	18	19	20	21	22
105.6538717	118.5490147	133.0102503	147.7264255	93.3219737	77.4504042	87.2039544	97.2819538	105.5339569	114.5508060	124.2116037	134.8796214	12.5028931
0.6537905	0.6860968	0.7198434	0.7517209	0.4716384	0.4946662	0.5188142	0.5441914	0.5652487	0.5866875	0.6077066	0.6302835	0.0506290
0	0	0	0	0	0	0	0	0	0	0	0	600.0000000
31.5756000	31.5756000	31.5756000	31.5756000	45.0865295	45.0865295	45.0865295	45.0865295	45.0865295	45.0865295	45.0865295	45.0865295	0.0000000
137.8832621	150.8107115	165.3056937	180.0537464	138.8801416	123.0315999	132.8092980	142.9126747	151.1857351	160.2240230	169.9058398	180.5964344	612.5535220
1767.788555	1709.444672	1634.695297	1541.095816	1427.460923	1351.463523	1288.379401	1211.961924	1121.218853	1017.370734	898.9754707	764.6482289	612.553522

0 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	159.4843774	159.4843774	159.4843774	159.4843774	159.4843774	159.4843774	159.4843774	159.4843774	159.4843774
Change in VoLL costs	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	0	0	0	0	0	0	0	0	0
Sum	160.6907236	160.6907236	160.6907236	160.6907236	160.6907236	160.6907236	160.6907236	160.6907236	160.6907236
PV with 4 percent discount rate	2404	2352.937055	2299.227953	2242.897846	2183.81883	2121.856758	2056.870937	1988.713807	1917.23061

10	11	12	13	14	15	16	17	18	19	20	21	22
159.4843774	159.4843774	159.4843774	159.4843774	159.4843774	159.4843774	159.4843774	159.4843774	159.4843774	159.4843774	159.4843774	159.4508423	0.0001186
1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	1.206346284	0.619482046	0.002075138
0	0	0	0	0	0	0	0	0	0	0	0	600
0	0	0	0	0	0	0	0	0	0	0	0	0
160.6907236	160.6907236	160.6907236	160.6907236	160.6907236	160.6907236	160.6907236	160.6907236	160.6907236	160.6907236	160.6907236	160.0703243	600.0021937
1842.259033	1763.628843	1681.161499	1594.66975	1503.957202	1408.817883	1309.035765	1204.384279	1094.625801	979.5111091	858.7788203	732.1547958	600.0021937

Existing flexibility + households

34 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	214.0240641	275.5091508	417.4222109	284.0494657	12.5023736	0.0030239	0.0037483	0.0045173	0.0054317
Change in VoLL costs	0.5346682	0.6220594	0.7216343	0.5390306	0.0415382	0.0529187	0.0655944	0.0790528	0.0950550
Change in investments	0	0	0	0	5880.0000000	0	0	0	0
Change in network loss costs	19.6542000	19.6542000	19.6542000	28.6758000	0	0	0	0	0
Sum	234.2129323	295.7854103	437.7980452	313.2642963	5892.543912	0.055942574	0.069342643	0.083570074	0.100486757
PV with 4 percent discount rate	4626	4606.155885	4520.716554	4282.164932	4162.582987	-1814.383018	-1902.983582	-1995.921907	-2093.410544

10	11	12	13	14	15	16	17	18	19	20	21	22
0.0064118	0.0075192	0.0087520	0.0100230	0.0114378	0.0129842	0.0147916	0.0167518	0.0183755	0.0201482	0.0219269	0.0238089	0.0259521
0.1122059	0.1315866	0.1531599	0.1754024	0.2001615	0.2272244	0.2588528	0.2931564	0.3215705	0.3525932	0.3837207	0.4166563	0.4541611
0	0	0	0	0	0	0	0	0	0	0	0	-3894.0000000
0	0	0	0	0	0	0	0	0	0	0	0	0
0.118617706	0.139105827	0.161911879	0.18542544	0.211599278	0.240208612	0.273644362	0.309908162	0.339945934	0.372741367	0.405647581	0.440465247	-3893.519887
-2195.674369	-2302.947685	-2415.477426	-2533.522538	-2657.352912	-2787.253659	-2923.523569	-3066.478517	-3216.4477	-3373.766883	-3538.797638	-3711.916406	-3893.519887

16 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	431.9907484	246.0216748	264.1173139	315.5167421	380.6453591	456.1715447	266.2771700	277.8883112	322.6569690
Change in VoLL costs	0.958356393	0.657683769	0.705871108	0.752841332	0.802115557	0.857099333	0.606781931	0.641307081	0.677766869
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	0	9.27936	9.27936	9.27936	9.27936	9.27936	17.721	17.721	17.721
Sum	432.9491048	255.9587185	274.102545	325.5489435	390.7268347	466.308004	284.604952	296.2506183	341.0557358
PV with 4 percent discount rate	4495	4260.661428	4200.132202	4117.619904	3977.124024	3761.413372	3455.90651	3326.061074	3177.665206

10	11	12	13	14	15	16	17	18	19	20	21	22
371.1485231	425.8268493	154.0801429	142.5837350	158.4661101	176.8008193	198.4207094	223.4500894	246.2770124	271.1379228	300.3688593	333.0085765	12.5028931
0.711118338	0.745690394	0.377813451	0.396957602	0.417427539	0.438718044	0.460195851	0.48299781	0.501901071	0.520297255	0.540563945	0.560755677	0.050628956
0	0	0	0	0	0	0	0	0	0	0	0	600
17.721	17.721	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	32.5422	0
389.5806414	444.2935397	187.0001563	175.5228926	191.4257377	209.7817373	231.4231052	256.4752872	279.3211134	304.20042	333.4516232	366.1115322	612.553522
2975.036012	2711.625593	2377.977857	2297.897413	2225.946397	2133.805267	2017.915878	1873.67362	1696.117612	1485.936167	1239.404452	950.1633266	612.553522

0 percent load increase prediction

Flexibility for peak loads and in case of malfunction	1	2	3	4	5	6	7	8	9
Change in O&M costs	169.5595443	194.5595443	169.5595443	169.5595443	169.5595443	169.5595443	194.5595443	169.5595443	169.5595443
Change in VoLL costs	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421
Change in investments	0	0	0	0	0	0	0	0	0
Change in network loss costs	0	0	0	0	0	0	0	0	0
Sum	170.2271527	195.2271527	170.2271527	170.2271527	170.2271527	170.2271527	195.2271527	170.2271527	170.2271527
PV with 4 percent discount rate	2596	2544.155556	2463.556109	2405.24341	2344.08505	2279.942163	2212.669103	2115.893117	2040.614464

10	11	12	13	14	15	16	17	18	19	20	21	22
169.5595443	169.5595443	194.5595443	169.5595443	169.5595443	169.5595443	169.5595443	169.5595443	169.5595443	169.5595443	169.5595443	169.5595443	12.5001186
0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.667608421	0.002075138
0	0	0	0	0	0	0	0	0	0	0	0	600
0	0	0	0	0	0	0	0	0	0	0	0	0
170.2271527	170.2271527	195.2271527	170.2271527	170.2271527	170.2271527	170.2271527	170.2271527	170.2271527	170.2271527	170.2271527	170.2271527	612.5021937
1961.662212	1878.85709	1792.011078	1674.706981	1577.898444	1476.36565	1369.878056	1258.193867	1141.05949	1018.208956	889.3633151	754.2300071	612.5021937

Output from the regulatory model tool provided by Adapt Consulting

All alternatives with 34 percent load increase prediction

Case 1 – Investment

Scenario 1: Flexibility in case of malfunction

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Result	Discounted Change in Revenue Cap	RoR
2019	1	5414	226	-0.05 %	369	143	351.83	7.54 %
2020	2	5189	226	-0.05 %	358	132	325.46	7.54 %
2021	3	4963	226	-0.05 %	348	122	301.65	7.54 %
2022	4	4738	226	-0.04 %	337	111	278.52	7.54 %
2023	5	4 512	226	-0.04 %	326	100	256.89	7.54 %
2024	6	4 286	226	-0.04 %	315	89	236.68	7.54 %
2025	7	4 061	226	-0.04 %	304	78	217.78	7.54 %
2026	8	3 835	226	-0.04 %	294	68	200.82	7.54 %
2027	9	3 610	226	-0.04 %	283	57	184.31	7.54 %
2028	10	3 384	226	-0.04 %	272	46	168.90	7.54 %
2029	11	3 158	226	-0.04 %	261	35	154.53	7.54 %
2030	12	2 933	226	-0.04 %	250	24	141.13	7.54 %
2031	13	2 707	226	-0.04 %	240	14	129.18	7.54 %
2032	14	2 482	226	-0.04 %	229	3	117.53	7.54 %
2033	15	2 256	226	-0.04 %	218	-8	106.68	7.54 %
2034	16	2 030	226	-0.04 %	207	-19	96.58	7.54 %
2035	17	1 805	226	-0.03 %	196	-30	87.19	7.54 %
2036	18	1 579	226	-0.03 %	186	-40	78.89	7.55 %
2037	19	1 354	226	-0.03 %	175	-51	70.77	7.55 %
2038	20	1 128	226	-0.03 %	164	-62	63.24	7.55 %
2039	21	902	226	-0.03 %	153	-73	56.25	7.55 %
2040	22	677	226	-0.03 %	142	-84	49.78	7.55 %
2041	23	451	226	-0.03 %	132	-94	44.12	7.55 %
2042	24	226	226	-0.03 %	121	-105	38.56	7.55 %
2043	25	0	226	-0.03 %	110	-116	33.43	7.55 %
2044	26	0	0	0.00 %	0	0	0.00	7.55 %
2045	27	0	0	0.00 %	0	0	0.00	7.55 %
2046	28	0	0	0.00 %	0	0	0.00	7.55 %
2047	29	0	0	0.00 %	0	0	0.00	7.55 %
2048	30	0	0	0.00 %	0	0	0.00	7.55 %
2049	31	0	0	0.00 %	0	0	0.00	7.55 %
2050	32	0	0	0.00 %	0	0	0.00	7.55 %

Scenario 2: Flexibility for peak loads and in case of malfunction

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Result	Discounted Change in Revenue Cap	RoR
2019	1	5414	226	-0.05 %	369	143	351.83	7.54 %
2020	2	5189	226	-0.05 %	358	132	325.46	7.54 %
2021	3	4963	226	-0.05 %	348	122	301.65	7.54 %
2022	4	4738	226	-0.04 %	337	111	278.52	7.54 %
2023	5	4 512	226	-0.04 %	326	100	256.89	7.54 %
2024	6	4 286	226	-0.04 %	315	89	236.68	7.54 %
2025	7	4 061	226	-0.04 %	304	78	217.78	7.54 %
2026	8	3 835	226	-0.04 %	294	68	200.82	7.54 %
2027	9	3 610	226	-0.04 %	283	57	184.31	7.54 %
2028	10	3 384	226	-0.04 %	272	46	168.90	7.54 %
2029	11	3 158	226	-0.04 %	261	35	154.53	7.54 %
2030	12	2 933	226	-0.04 %	250	24	141.13	7.54 %
2031	13	2 707	226	-0.04 %	240	14	129.18	7.54 %
2032	14	2 482	226	-0.04 %	229	3	117.53	7.54 %
2033	15	2 256	226	-0.04 %	218	-8	106.68	7.54 %
2034	16	2 030	226	-0.04 %	207	-19	96.58	7.54 %
2035	17	1 805	226	-0.03 %	196	-30	87.19	7.54 %
2036	18	1 579	226	-0.03 %	186	-40	78.89	7.55 %
2037	19	1 354	226	-0.03 %	175	-51	70.77	7.55 %
2038	20	1 128	226	-0.03 %	164	-62	63.24	7.55 %
2039	21	902	226	-0.03 %	153	-73	56.25	7.55 %
2040	22	677	226	-0.03 %	142	-84	49.78	7.55 %
2041	23	451	226	-0.03 %	132	-94	44.12	7.55 %
2042	24	226	226	-0.03 %	121	-105	38.56	7.55 %
2043	25	0	226	-0.03 %	110	-116	33.43	7.55 %
2044	26	0	0	0.00 %	0	0	0.00	7.55 %
2045	27	0	0	0.00 %	0	0	0.00	7.55 %
2046	28	0	0	0.00 %	0	0	0.00	7.55 %
2047	29	0	0	0.00 %	0	0	0.00	7.55 %
2048	30	0	0	0.00 %	0	0	0.00	7.55 %
2049	31	0	0	0.00 %	0	0	0.00	7.55 %
2050	32	0	0	0.00 %	0	0	0.00	7.55 %

Case 2 – Compensating through a tariff discount

Scenario 1: Flexibility in case of malfunction

Existing flexibility

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Result	Discounted Change in Revenue Cap	RoR
2019	1	0	0	-0.01 %	24	-25	22.88	7.55 %
2020	2	0	0	-0.01 %	24	-25	21.82	7.55 %
2021	3	0	0	-0.01 %	24	-25	20.80	7.55 %
2022	4	5587	233	-0.05 %	383	146	316.54	7.54 %
2023	5	5 354	233	-0.05 %	372	135	293.14	7.54 %
2024	6	5 122	233	-0.05 %	361	124	271.24	7.54 %
2025	7	4 889	233	-0.05 %	350	113	250.74	7.54 %
2026	8	4 656	233	-0.05 %	339	102	231.56	7.54 %
2027	9	4 423	233	-0.04 %	327	90	212.97	7.54 %
2028	10	4 190	233	-0.04 %	316	79	196.23	7.54 %
2029	11	3 958	233	-0.04 %	305	68	180.58	7.54 %
2030	12	3 725	233	-0.04 %	294	57	165.97	7.54 %
2031	13	3 492	233	-0.04 %	283	46	152.33	7.54 %
2032	14	3 259	233	-0.04 %	272	35	139.60	7.54 %
2033	15	3 026	233	-0.04 %	261	24	127.72	7.54 %
2034	16	2 794	233	-0.04 %	249	12	116.18	7.54 %
2035	17	2 561	233	-0.04 %	238	1	105.88	7.54 %
2036	18	2 328	233	-0.04 %	227	-10	96.28	7.54 %
2037	19	2 095	233	-0.04 %	216	-21	87.36	7.54 %
2038	20	1 862	233	-0.04 %	205	-32	79.05	7.54 %
2039	21	1 630	233	-0.04 %	194	-43	71.33	7.55 %
2040	22	1 397	233	-0.03 %	183	-54	64.15	7.55 %
2041	23	1 164	233	-0.03 %	171	-66	57.16	7.55 %
2042	24	931	233	-0.03 %	160	-77	50.99	7.55 %
2043	25	698	233	-0.03 %	149	-88	45.28	7.55 %
2044	26	466	233	-0.03 %	138	-99	39.98	7.55 %
2045	27	233	233	-0.03 %	127	-110	35.08	7.55 %
2046	28	0	233	-0.03 %	116	-121	30.55	7.55 %
2047	29	0	0	0.00 %	2	-2	0.50	7.55 %
2048	30	0	0	0.00 %	2	-2	0.48	7.55 %
2049	31	0	0	0.00 %	2	-2	0.46	7.55 %
2050	32	0	0	0.00 %	2	-2	0.44	7.55 %

Existing flexibility + households

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Result	Discounted Change in Revenue Cap	RoR
2019	1	0	0	-0.01 %	26	-26	24.79	7.55 %
2020	2	0	0	-0.01 %	26	-26	23.64	7.55 %
2021	3	0	0	-0.01 %	26	-26	22.54	7.55 %
2022	4	0	0	-0.01 %	26	-26	21.49	7.55 %
2023	5	5 645	235	-0.05 %	387	147	304.96	7.54 %
2024	6	5 410	235	-0.05 %	376	136	282.51	7.54 %
2025	7	5 174	235	-0.05 %	365	125	261.48	7.54 %
2026	8	4 939	235	-0.05 %	353	113	241.12	7.54 %
2027	9	4 704	235	-0.05 %	342	102	222.74	7.54 %
2028	10	4 469	235	-0.05 %	331	91	205.54	7.54 %
2029	11	4 234	235	-0.04 %	320	80	189.47	7.54 %
2030	12	3 998	235	-0.04 %	308	68	173.88	7.54 %
2031	13	3 763	235	-0.04 %	297	57	159.86	7.54 %
2032	14	3 528	235	-0.04 %	286	46	146.78	7.54 %
2033	15	3 293	235	-0.04 %	274	34	134.08	7.54 %
2034	16	3 058	235	-0.04 %	263	23	122.71	7.54 %
2035	17	2 822	235	-0.04 %	252	12	112.11	7.54 %
2036	18	2 587	235	-0.04 %	241	1	102.22	7.54 %
2037	19	2 352	235	-0.04 %	229	-11	92.61	7.54 %
2038	20	2 117	235	-0.04 %	218	-22	84.06	7.54 %
2039	21	1 882	235	-0.04 %	207	-33	76.11	7.54 %
2040	22	1 646	235	-0.04 %	196	-44	68.71	7.55 %
2041	23	1 411	235	-0.04 %	184	-56	61.50	7.55 %
2042	24	1 176	235	-0.03 %	173	-67	55.13	7.55 %
2043	25	941	235	-0.03 %	162	-78	49.23	7.55 %
2044	26	706	235	-0.03 %	151	-89	43.75	7.55 %
2045	27	470	235	-0.03 %	139	-101	38.40	7.55 %
2046	28	235	235	-0.03 %	128	-112	33.71	7.55 %
2047	29	0	235	-0.03 %	117	-123	29.38	7.55 %
2048	30	0	0	0.00 %	2	-2	0.48	7.55 %
2049	31	0	0	0.00 %	2	-2	0.46	7.55 %
2050	32	0	0	0.00 %	2	-2	0.44	7.55 %

Scenario 2: Flexibility for peak loads and in case of malfunction

Existing flexibility

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Result	Discounted Change in Revenue Cap	RoR
2019	1	0	0	0.00 %	11	-11	10.49	7.55 %
2020	2	0	0	0.00 %	11	-11	10.00	7.55 %
2021	3	0	0	0.00 %	11	-11	9.53	7.55 %
2022	4	5587	233	-0.05 %	383	146	316.54	7.54 %
2023	5	5 354	233	-0.05 %	372	135	293.14	7.54 %
2024	6	5 122	233	-0.05 %	361	124	271.24	7.54 %
2025	7	4 889	233	-0.05 %	350	113	250.74	7.54 %
2026	8	4 656	233	-0.05 %	339	102	231.56	7.54 %
2027	9	4 423	233	-0.04 %	327	90	212.97	7.54 %
2028	10	4 190	233	-0.04 %	316	79	196.23	7.54 %
2029	11	3 958	233	-0.04 %	305	68	180.58	7.54 %
2030	12	3 725	233	-0.04 %	294	57	165.97	7.54 %
2031	13	3 492	233	-0.04 %	283	46	152.33	7.54 %
2032	14	3 259	233	-0.04 %	272	35	139.60	7.54 %
2033	15	3 026	233	-0.04 %	261	24	127.72	7.54 %
2034	16	2 794	233	-0.04 %	249	12	116.18	7.54 %
2035	17	2 561	233	-0.04 %	238	1	105.88	7.54 %
2036	18	2 328	233	-0.04 %	227	-10	96.28	7.54 %
2037	19	2 095	233	-0.04 %	216	-21	87.36	7.54 %
2038	20	1 862	233	-0.04 %	205	-32	79.05	7.54 %
2039	21	1 630	233	-0.04 %	194	-43	71.33	7.54 %
2040	22	1 397	233	-0.03 %	183	-54	64.15	7.54 %
2041	23	1 164	233	-0.03 %	171	-66	57.16	7.55 %
2042	24	931	233	-0.03 %	160	-77	50.99	7.55 %
2043	25	698	233	-0.03 %	149	-88	45.28	7.55 %
2044	26	466	233	-0.03 %	138	-99	39.98	7.55 %
2045	27	233	233	-0.03 %	127	-110	35.08	7.55 %
2046	28	0	233	-0.03 %	116	-121	30.55	7.55 %
2047	29	0	0	0.00 %	2	-2	0.50	7.55 %
2048	30	0	0	0.00 %	2	-2	0.48	7.55 %
2049	31	0	0	0.00 %	2	-2	0.46	7.55 %
2050	32	0	0	0.00 %	2	-2	0.44	7.55 %

Existing flexibility + households

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Result	Discounted Change in Revenue Cap	RoR
2019	1	0	0	0.00 %	12	-11	11.44	7.55 %
2020	2	0	0	0.00 %	12	-11	10.91	7.55 %
2021	3	0	0	0.00 %	12	-11	10.40	7.55 %
2022	4	0	0	0.00 %	12	-11	9.92	7.55 %
2023	5	5 645	235	-0.05 %	387	147	304.96	7.54 %
2024	6	5 410	235	-0.05 %	376	136	282.51	7.54 %
2025	7	5 174	235	-0.05 %	365	125	261.48	7.54 %
2026	8	4 939	235	-0.05 %	353	113	241.12	7.54 %
2027	9	4 704	235	-0.05 %	342	102	222.74	7.54 %
2028	10	4 469	235	-0.05 %	331	91	205.54	7.54 %
2029	11	4 234	235	-0.04 %	320	80	189.47	7.54 %
2030	12	3 998	235	-0.04 %	308	68	173.88	7.54 %
2031	13	3 763	235	-0.04 %	297	57	159.86	7.54 %
2032	14	3 528	235	-0.04 %	286	46	146.78	7.54 %
2033	15	3 293	235	-0.04 %	274	34	134.08	7.54 %
2034	16	3 058	235	-0.04 %	263	23	122.71	7.54 %
2035	17	2 822	235	-0.04 %	252	12	112.11	7.54 %
2036	18	2 587	235	-0.04 %	241	1	102.22	7.54 %
2037	19	2 352	235	-0.04 %	229	-11	92.61	7.54 %
2038	20	2 117	235	-0.04 %	218	-22	84.06	7.54 %
2039	21	1 882	235	-0.04 %	207	-33	76.11	7.54 %
2040	22	1 646	235	-0.04 %	196	-44	68.71	7.55 %
2041	23	1 411	235	-0.04 %	184	-56	61.50	7.55 %
2042	24	1 176	235	-0.03 %	173	-67	55.13	7.55 %
2043	25	941	235	-0.03 %	162	-78	49.23	7.55 %
2044	26	706	235	-0.03 %	151	-89	43.75	7.55 %
2045	27	470	235	-0.03 %	139	-101	38.40	7.55 %
2046	28	235	235	-0.03 %	128	-112	33.71	7.55 %
2047	29	0	235	-0.03 %	117	-123	29.38	7.55 %
2048	30	0	0	0.00 %	2	-2	0.48	7.55 %
2049	31	0	0	0.00 %	2	-2	0.46	7.55 %
2050	32	0	0	0.00 %	2	-2	0.44	7.55 %

Case 3 – Compensation through availability and activation

Scenario 1: Flexibility in case of malfunction

Existing flexibility

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Result	Discounted Change in Revenue Cap	RoR
2019	1	0	0	-0.01 %	59	-57	56.25	7.55 %
2020	2	0	0	-0.01 %	59	-57	53.64	7.55 %
2021	3	0	0	-0.01 %	59	-57	51.14	7.55 %
2022	4	5587	233	-0.05 %	383	146	316.54	7.54 %
2023	5	5 354	233	-0.05 %	372	135	293.14	7.54 %
2024	6	5 122	233	-0.05 %	361	124	271.24	7.54 %
2025	7	4 889	233	-0.05 %	350	113	250.74	7.54 %
2026	8	4 656	233	-0.05 %	339	102	231.56	7.54 %
2027	9	4 423	233	-0.04 %	327	90	212.97	7.54 %
2028	10	4 190	233	-0.04 %	316	79	196.23	7.54 %
2029	11	3 958	233	-0.04 %	305	68	180.58	7.54 %
2030	12	3 725	233	-0.04 %	294	57	165.97	7.54 %
2031	13	3 492	233	-0.04 %	283	46	152.33	7.54 %
2032	14	3 259	233	-0.04 %	272	35	139.60	7.54 %
2033	15	3 026	233	-0.04 %	261	24	127.72	7.54 %
2034	16	2 794	233	-0.04 %	249	12	116.18	7.54 %
2035	17	2 561	233	-0.04 %	238	1	105.88	7.54 %
2036	18	2 328	233	-0.04 %	227	-10	96.28	7.54 %
2037	19	2 095	233	-0.04 %	216	-21	87.36	7.54 %
2038	20	1 862	233	-0.04 %	205	-32	79.05	7.54 %
2039	21	1 630	233	-0.04 %	194	-43	71.33	7.55 %
2040	22	1 397	233	-0.03 %	183	-54	64.15	7.55 %
2041	23	1 164	233	-0.03 %	171	-66	57.16	7.55 %
2042	24	931	233	-0.03 %	160	-77	50.99	7.55 %
2043	25	698	233	-0.03 %	149	-88	45.28	7.55 %
2044	26	466	233	-0.03 %	138	-99	39.98	7.55 %
2045	27	233	233	-0.03 %	127	-110	35.08	7.55 %
2046	28	0	233	-0.03 %	116	-121	30.55	7.55 %
2047	29	0	0	0.00 %	2	-2	0.50	7.55 %
2048	30	0	0	0.00 %	2	-2	0.48	7.55 %
2049	31	0	0	0.00 %	2	-2	0.46	7.55 %
2050	32	0	0	0.00 %	2	-2	0.44	7.55 %

Existing flexibility + households

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Result	Discounted Change in Revenue Cap	RoR
2019	1	0	0	-0.02 %	74	-71	70.56	7.55 %
2020	2	0	0	-0.02 %	74	-71	67.27	7.55 %
2021	3	0	0	-0.02 %	74	-71	64.14	7.55 %
2022	4	0	0	-0.02 %	74	-71	61.16	7.55 %
2023	5	5 645	235	-0.05 %	387	147	304.96	7.54 %
2024	6	5 410	235	-0.05 %	376	136	282.51	7.54 %
2025	7	5 174	235	-0.05 %	365	125	261.48	7.54 %
2026	8	4 939	235	-0.05 %	353	113	241.12	7.54 %
2027	9	4 704	235	-0.05 %	342	102	222.74	7.54 %
2028	10	4 469	235	-0.05 %	331	91	205.54	7.54 %
2029	11	4 234	235	-0.04 %	320	80	189.47	7.54 %
2030	12	3 998	235	-0.04 %	308	68	173.88	7.54 %
2031	13	3 763	235	-0.04 %	297	57	159.86	7.54 %
2032	14	3 528	235	-0.04 %	286	46	146.78	7.54 %
2033	15	3 293	235	-0.04 %	274	34	134.08	7.54 %
2034	16	3 058	235	-0.04 %	263	23	122.71	7.54 %
2035	17	2 822	235	-0.04 %	252	12	112.11	7.54 %
2036	18	2 587	235	-0.04 %	241	1	102.22	7.54 %
2037	19	2 352	235	-0.04 %	229	-11	92.61	7.54 %
2038	20	2 117	235	-0.04 %	218	-22	84.06	7.54 %
2039	21	1 882	235	-0.04 %	207	-33	76.11	7.54 %
2040	22	1 646	235	-0.04 %	196	-44	68.71	7.55 %
2041	23	1 411	235	-0.04 %	184	-56	61.50	7.55 %
2042	24	1 176	235	-0.03 %	173	-67	55.13	7.55 %
2043	25	941	235	-0.03 %	162	-78	49.23	7.55 %
2044	26	706	235	-0.03 %	151	-89	43.75	7.55 %
2045	27	470	235	-0.03 %	139	-101	38.40	7.55 %
2046	28	235	235	-0.03 %	128	-112	33.71	7.55 %
2047	29	0	235	-0.03 %	117	-123	29.38	7.55 %
2048	30	0	0	0.00 %	2	-2	0.48	7.55 %
2049	31	0	0	0.00 %	2	-2	0.46	7.55 %
2050	32	0	0	0.00 %	2	-2	0.44	7.55 %

Scenario 2: Flexibility for peak loads and in case of malfunction

Existing flexibility

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Result	Discounted Change in Revenue Cap	RoR
2019	1	0	0	-0.02 %	71	-69	67.70	7.55 %
2020	2	0	0	-0.02 %	71	-69	64.55	7.55 %
2021	3	0	0	-0.02 %	71	-69	61.54	7.55 %
2022	4	5587	233	-0.05 %	383	146	316.54	7.54 %
2023	5	5 354	233	-0.05 %	372	135	293.14	7.54 %
2024	6	5 122	233	-0.05 %	361	124	271.24	7.54 %
2025	7	4 889	233	-0.05 %	350	113	250.74	7.54 %
2026	8	4 656	233	-0.05 %	339	102	231.56	7.54 %
2027	9	4 423	233	-0.04 %	327	90	212.97	7.54 %
2028	10	4 190	233	-0.04 %	316	79	196.23	7.54 %
2029	11	3 958	233	-0.04 %	305	68	180.58	7.54 %
2030	12	3 725	233	-0.04 %	294	57	165.97	7.54 %
2031	13	3 492	233	-0.04 %	283	46	152.33	7.54 %
2032	14	3 259	233	-0.04 %	272	35	139.60	7.54 %
2033	15	3 026	233	-0.04 %	261	24	127.72	7.54 %
2034	16	2 794	233	-0.04 %	249	12	116.18	7.54 %
2035	17	2 561	233	-0.04 %	238	1	105.88	7.54 %
2036	18	2 328	233	-0.04 %	227	-10	96.28	7.54 %
2037	19	2 095	233	-0.04 %	216	-21	87.36	7.54 %
2038	20	1 862	233	-0.04 %	205	-32	79.05	7.54 %
2039	21	1 630	233	-0.04 %	194	-43	71.33	7.55 %
2040	22	1 397	233	-0.03 %	183	-54	64.15	7.55 %
2041	23	1 164	233	-0.03 %	171	-66	57.16	7.55 %
2042	24	931	233	-0.03 %	160	-77	50.99	7.55 %
2043	25	698	233	-0.03 %	149	-88	45.28	7.55 %
2044	26	466	233	-0.03 %	138	-99	39.98	7.55 %
2045	27	233	233	-0.03 %	127	-110	35.08	7.55 %
2046	28	0	233	-0.03 %	116	-121	30.55	7.55 %
2047	29	0	0	0.00 %	2	-2	0.50	7.55 %
2048	30	0	0	0.00 %	2	-2	0.48	7.55 %
2049	31	0	0	0.00 %	2	-2	0.46	7.55 %
2050	32	0	0	0.00 %	2	-2	0.44	7.55 %

Existing flexibility + households

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Result	Discounted Change in Revenue Cap	RoR
2019	1	0	0	-0.04 %	158	-150	150.65	7.55 %
2020	2	0	0	-0.04 %	158	-150	143.64	7.55 %
2021	3	0	0	-0.04 %	158	-150	136.96	7.55 %
2022	4	0	0	-0.04 %	158	-150	130.58	7.55 %
2023	5	5 645	235	-0.05 %	385	149	303.39	7.54 %
2024	6	5 410	235	-0.05 %	374	138	281.01	7.54 %
2025	7	5 174	235	-0.05 %	363	127	260.05	7.54 %
2026	8	4 939	235	-0.05 %	351	115	239.75	7.54 %
2027	9	4 704	235	-0.05 %	340	104	221.43	7.54 %
2028	10	4 469	235	-0.04 %	329	93	204.30	7.54 %
2029	11	4 234	235	-0.04 %	318	82	188.28	7.54 %
2030	12	3 998	235	-0.04 %	306	70	172.75	7.54 %
2031	13	3 763	235	-0.04 %	295	59	158.79	7.54 %
2032	14	3 528	235	-0.04 %	284	48	145.75	7.54 %
2033	15	3 293	235	-0.04 %	273	37	133.59	7.54 %
2034	16	3 058	235	-0.04 %	261	25	121.77	7.54 %
2035	17	2 822	235	-0.04 %	250	14	111.22	7.54 %
2036	18	2 587	235	-0.04 %	239	3	101.37	7.54 %
2037	19	2 352	235	-0.04 %	228	-8	92.21	7.54 %
2038	20	2 117	235	-0.04 %	216	-20	83.29	7.54 %
2039	21	1 882	235	-0.04 %	205	-31	75.37	7.54 %
2040	22	1 646	235	-0.04 %	194	-42	68.01	7.55 %
2041	23	1 411	235	-0.03 %	183	-53	61.17	7.55 %
2042	24	1 176	235	-0.03 %	171	-65	54.50	7.55 %
2043	25	941	235	-0.03 %	160	-76	48.62	7.55 %
2044	26	706	235	-0.03 %	149	-87	43.17	7.55 %
2045	27	470	235	-0.03 %	138	-98	38.12	7.55 %
2046	28	235	235	-0.03 %	126	-110	33.19	7.55 %
2047	29	0	235	-0.03 %	115	-121	28.88	7.55 %
2048	30	0	0	0.00 %	0	-1	0.00	7.55 %
2049	31	0	0	0.00 %	0	-1	0.00	7.55 %
2050	32	0	0	0.00 %	0	-1	0.00	7.55 %

Case 4 – Compensation through activation

Scenario 1: Flexibility in case of malfunction

Existing flexibility

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Result	Discounted Change in Revenue Cap	RoR
2019	1	0	0	-0.01 %	24	-25	22.88	7.55 %
2020	2	0	0	-0.01 %	24	-25	21.82	7.55 %
2021	3	0	0	-0.01 %	24	-25	20.80	7.55 %
2022	4	5587	233	-0.05 %	383	146	316.54	7.54 %
2023	5	5 354	233	-0.05 %	372	135	293.14	7.54 %
2024	6	5 122	233	-0.05 %	361	124	271.24	7.54 %
2025	7	4 889	233	-0.05 %	350	113	250.74	7.54 %
2026	8	4 656	233	-0.05 %	339	102	231.56	7.54 %
2027	9	4 423	233	-0.04 %	327	90	212.97	7.54 %
2028	10	4 190	233	-0.04 %	316	79	196.23	7.54 %
2029	11	3 958	233	-0.04 %	305	68	180.58	7.54 %
2030	12	3 725	233	-0.04 %	294	57	165.97	7.54 %
2031	13	3 492	233	-0.04 %	283	46	152.33	7.54 %
2032	14	3 259	233	-0.04 %	272	35	139.60	7.54 %
2033	15	3 026	233	-0.04 %	261	24	127.72	7.54 %
2034	16	2 794	233	-0.04 %	249	12	116.18	7.54 %
2035	17	2 561	233	-0.04 %	238	1	105.88	7.54 %
2036	18	2 328	233	-0.04 %	227	-10	96.28	7.54 %
2037	19	2 095	233	-0.04 %	216	-21	87.36	7.54 %
2038	20	1 862	233	-0.04 %	205	-32	79.05	7.54 %
2039	21	1 630	233	-0.04 %	194	-43	71.33	7.55 %
2040	22	1 397	233	-0.03 %	183	-54	64.15	7.55 %
2041	23	1 164	233	-0.03 %	171	-66	57.16	7.55 %
2042	24	931	233	-0.03 %	160	-77	50.99	7.55 %
2043	25	698	233	-0.03 %	149	-88	45.28	7.55 %
2044	26	466	233	-0.03 %	138	-99	39.98	7.55 %
2045	27	233	233	-0.03 %	127	-110	35.08	7.55 %
2046	28	0	233	-0.03 %	116	-121	30.55	7.55 %
2047	29	0	0	0.00 %	2	-2	0.50	7.55 %
2048	30	0	0	0.00 %	2	-2	0.48	7.55 %
2049	31	0	0	0.00 %	2	-2	0.46	7.55 %
2050	32	0	0	0.00 %	2	-2	0.44	7.55 %

Existing flexibility + households

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Result	Discounted Change in Revenue Cap	RoR
2019	1	0	0	-0.01 %	27	-27	25.74	7.55 %
2020	2	0	0	-0.01 %	27	-27	24.55	7.55 %
2021	3	0	0	-0.01 %	27	-27	23.40	7.55 %
2022	4	0	0	-0.01 %	27	-27	22.31	7.55 %
2023	5	5 645	235	-0.05 %	387	147	304.96	7.54 %
2024	6	5 410	235	-0.05 %	376	136	282.51	7.54 %
2025	7	5 174	235	-0.05 %	365	125	261.48	7.54 %
2026	8	4 939	235	-0.05 %	353	113	241.12	7.54 %
2027	9	4 704	235	-0.05 %	342	102	222.74	7.54 %
2028	10	4 469	235	-0.05 %	331	91	205.54	7.54 %
2029	11	4 234	235	-0.04 %	320	80	189.47	7.54 %
2030	12	3 998	235	-0.04 %	308	68	173.88	7.54 %
2031	13	3 763	235	-0.04 %	297	57	159.86	7.54 %
2032	14	3 528	235	-0.04 %	286	46	146.78	7.54 %
2033	15	3 293	235	-0.04 %	274	34	134.08	7.54 %
2034	16	3 058	235	-0.04 %	263	23	122.71	7.54 %
2035	17	2 822	235	-0.04 %	252	12	112.11	7.54 %
2036	18	2 587	235	-0.04 %	241	1	102.22	7.54 %
2037	19	2 352	235	-0.04 %	229	-11	92.61	7.54 %
2038	20	2 117	235	-0.04 %	218	-22	84.06	7.54 %
2039	21	1 882	235	-0.04 %	207	-33	76.11	7.54 %
2040	22	1 646	235	-0.04 %	196	-44	68.71	7.55 %
2041	23	1 411	235	-0.04 %	184	-56	61.50	7.55 %
2042	24	1 176	235	-0.03 %	173	-67	55.13	7.55 %
2043	25	941	235	-0.03 %	162	-78	49.23	7.55 %
2044	26	706	235	-0.03 %	151	-89	43.75	7.55 %
2045	27	470	235	-0.03 %	139	-101	38.40	7.55 %
2046	28	235	235	-0.03 %	128	-112	33.71	7.55 %
2047	29	0	235	-0.03 %	117	-123	29.38	7.55 %
2048	30	0	0	0.00 %	2	-2	0.48	7.55 %
2049	31	0	0	0.00 %	2	-2	0.46	7.55 %
2050	32	0	0	0.00 %	2	-2	0.44	7.55 %

Scenario 2: Flexibility for peak loads and in case of malfunction

Existing flexibility

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Result	Discounted Change in Revenue Cap	RoR
2019	1	0	0	-0.01 %	50	-48	47.67	7.55 %
2020	2	0	0	-0.01 %	50	-48	45.46	7.55 %
2021	3	0	0	-0.01 %	50	-48	43.34	7.55 %
2022	4	5587	233	-0.05 %	383	146	316.54	7.54 %
2023	5	5 354	233	-0.05 %	372	135	293.14	7.54 %
2024	6	5 122	233	-0.05 %	361	124	271.24	7.54 %
2025	7	4 889	233	-0.05 %	350	113	250.74	7.54 %
2026	8	4 656	233	-0.05 %	339	102	231.56	7.54 %
2027	9	4 423	233	-0.04 %	327	90	212.97	7.54 %
2028	10	4 190	233	-0.04 %	316	79	196.23	7.54 %
2029	11	3 958	233	-0.04 %	305	68	180.58	7.54 %
2030	12	3 725	233	-0.04 %	294	57	165.97	7.54 %
2031	13	3 492	233	-0.04 %	283	46	152.33	7.54 %
2032	14	3 259	233	-0.04 %	272	35	139.60	7.54 %
2033	15	3 026	233	-0.04 %	261	24	127.72	7.54 %
2034	16	2 794	233	-0.04 %	249	12	116.18	7.54 %
2035	17	2 561	233	-0.04 %	238	1	105.88	7.54 %
2036	18	2 328	233	-0.04 %	227	-10	96.28	7.54 %
2037	19	2 095	233	-0.04 %	216	-21	87.36	7.54 %
2038	20	1 862	233	-0.04 %	205	-32	79.05	7.54 %
2039	21	1 630	233	-0.04 %	194	-43	71.33	7.55 %
2040	22	1 397	233	-0.03 %	183	-54	64.15	7.55 %
2041	23	1 164	233	-0.03 %	171	-66	57.16	7.55 %
2042	24	931	233	-0.03 %	160	-77	50.99	7.55 %
2043	25	698	233	-0.03 %	149	-88	45.28	7.55 %
2044	26	466	233	-0.03 %	138	-99	39.98	7.55 %
2045	27	233	233	-0.03 %	127	-110	35.08	7.55 %
2046	28	0	233	-0.03 %	116	-121	30.55	7.55 %
2047	29	0	0	0.00 %	2	-2	0.50	7.55 %
2048	30	0	0	0.00 %	2	-2	0.48	7.55 %
2049	31	0	0	0.00 %	2	-2	0.46	7.55 %
2050	32	0	0	0.00 %	2	-2	0.44	7.55 %

Existing flexibility + households

Year	Year (number)	Book value	Depreciation	Change in Efficiency	Change in Revenue Cap	Change in Operational Result	Discounted Change in Revenue Cap	RoR
2019	1	0	0	-0.04 %	160	-152	152.56	7.55 %
2020	2	0	0	-0.04 %	160	-152	145.46	7.55 %
2021	3	0	0	-0.04 %	160	-152	138.69	7.55 %
2022	4	0	0	-0.04 %	160	-152	132.24	7.55 %
2023	5	5 645	235	-0.05 %	387	147	304.96	7.54 %
2024	6	5 410	235	-0.05 %	376	136	282.51	7.54 %
2025	7	5 174	235	-0.05 %	365	125	261.48	7.54 %
2026	8	4 939	235	-0.05 %	353	113	241.12	7.54 %
2027	9	4 704	235	-0.05 %	342	102	222.74	7.54 %
2028	10	4 469	235	-0.05 %	331	91	205.54	7.54 %
2029	11	4 234	235	-0.04 %	320	80	189.47	7.54 %
2030	12	3 998	235	-0.04 %	308	68	173.88	7.54 %
2031	13	3 763	235	-0.04 %	297	57	159.86	7.54 %
2032	14	3 528	235	-0.04 %	286	46	146.78	7.54 %
2033	15	3 293	235	-0.04 %	274	34	134.08	7.54 %
2034	16	3 058	235	-0.04 %	263	23	122.71	7.54 %
2035	17	2 822	235	-0.04 %	252	12	112.11	7.54 %
2036	18	2 587	235	-0.04 %	241	1	102.22	7.54 %
2037	19	2 352	235	-0.04 %	229	-11	92.61	7.54 %
2038	20	2 117	235	-0.04 %	218	-22	84.06	7.54 %
2039	21	1 882	235	-0.04 %	207	-33	76.11	7.54 %
2040	22	1 646	235	-0.04 %	196	-44	68.71	7.55 %
2041	23	1 411	235	-0.04 %	184	-56	61.50	7.55 %
2042	24	1 176	235	-0.03 %	173	-67	55.13	7.55 %
2043	25	941	235	-0.03 %	162	-78	49.23	7.55 %
2044	26	706	235	-0.03 %	151	-89	43.75	7.55 %
2045	27	470	235	-0.03 %	139	-101	38.40	7.55 %
2046	28	235	235	-0.03 %	128	-112	33.71	7.55 %
2047	29	0	235	-0.03 %	117	-123	29.38	7.55 %
2048	30	0	0	0.00 %	2	-2	0.48	7.55 %
2049	31	0	0	0.00 %	2	-2	0.46	7.55 %
2050	32	0	0	0.00 %	2	-2	0.44	7.55 %