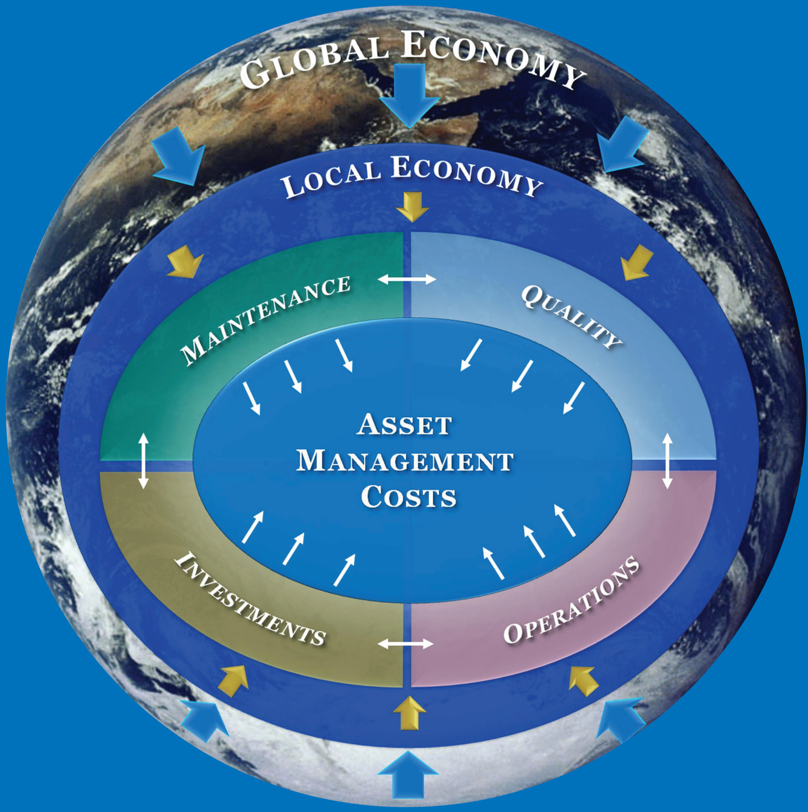
Department of Electrical Engineering

Dynamic Scenario Modelling in Electricity Distribution System Asset Management

Jussi Palola



Aalto University

DOCTORAL DISSERTATIONS

Aalto University publication series
DOCTORAL DISSERTATIONS 9/2014

Dynamic Scenario Modelling in Electricity Distribution System Asset Management

Jussi Palola

A doctoral dissertation completed for the degree of Doctor of Science in Technology to be defended, with the permission of the Aalto University School of Electrical Engineering, at a public examination held at the lecture hall S1 of the school on the 24th of January 2014 at 12 noon.

Aalto University
School of Electrical Engineering
Department of Electrical Engineering
Power Systems and High Voltage Engineering

Supervising professor
Prof. Matti Lehtonen

Thesis advisor
Dr. Markku Hyvärinen, Helen Electricity Network Ltd.

Preliminary examiners
Prof. Mehdi Vakilian, Sharif University of Technology, Iran
Prof. Josu Takala, University of Vaasa, Finland

Opponents
Prof. Josu Takala, University of Vaasa, Finland
Dr. Dejan Susa, STATNETT, Norway

Aalto University publication series
DOCTORAL DISSERTATIONS 9/2014

ISBN 978-952-60-5538-1
ISBN 978-952-60-5539-8 (pdf)
ISSN-L 1799-4934
ISSN 1799-4934 (printed)
ISSN 1799-4942 (pdf)
http://urn.fi/URN:ISBN:978-952-60-5539-8

Unigrafia Oy
Helsinki 2014

Finland

441 697
Printed matter

Aalto University

Aalto University, P.O. Box 11000, FI-00076 Aalto www.aalto.fi

Abstract

Author
Jussi Palola

Name of the doctoral dissertation
Dynamic Scenario Modelling in Electricity Distribution System Asset Management

Publisher School of Electrical Engineering

Unit Department of Electrical Engineering

Series Aalto University publication series DOCTORAL DISSERTATIONS 9/2014

Field of research Power Systems and High Voltage Engineering

Manuscript submitted 9 September 2013 **Date of the defence** 24 January 2014

Permission to publish granted (date) 12 November 2013 **Language** English

☒ **Monograph** ☐ **Article dissertation (summary + original articles)**

Abstract

The life of individuals, societal welfare and global economics are deeply interconnected with power systems in a multidimensional manner. A change in one entity affects the whole system. This thesis is a research journey from electrical distribution systems to global economics, and finally to power transformer unit asset management. The objective is to investigate dynamic scenario modelling in power system asset management and apply it to a distribution system operator's power transformer fleet assets.

The asset management of a distribution system is directly coupled to the economy, both globally and locally. Economic attributes affect electrical network asset management from many directions simultaneously: electricity demand, network expansion requirements, and component, construction and operational expenditures.

A comprehensive cost function is formed and applied with different economic scenarios for asset management. Revealing the dynamics of power transformer asset management with scenarios is relevant in an increasingly turbulent global environment. This thesis offers an approach to assess the techno-economic dependencies in electricity distribution system asset management for more pertinent decision making. Understanding the dynamic balance between asset management and overall expenses is increasingly important while seeking economic efficiency and return on investments.

Keywords Asset Management, Scenario Modelling, Decision analysis, Power transformers, Electricity distribution

ISBN (printed) 978-952-60-5538-1 **ISBN (pdf)** 978-952-60-5539-8

ISSN-L 1799-4934 **ISSN (printed)** 1799-4934 **ISSN (pdf)** 1799-4942

Location of publisher Helsinki **Location of printing** Helsinki **Year** 2014

Pages 210 **urn** http://urn.fi/URN:ISBN:978-952-60-5539-8

Aalto-yliopisto

Aalto-yliopisto, PL 11000, 00076 Aalto www.aalto.fi

Tiivistelmä

Tekijä
Jussi Palola

Väitöskirjan nimi
Dynaaminen skenaariomallinnus sähköverkon omaisuuden hallinnassa

Julkaisija Sähkötekniikan korkeakoulu

Yksikkö Sähkötekniikan laitos

Sarja Aalto University publication series DOCTORAL DISSERTATIONS 9/2014

Tutkimusala Sähköverkot ja suurjännitetekniikka

Käsikirjoituksen pvm 09.09.2013 **Väitöspäivä** 24.01.2014

Julkaisuluvan myöntämispäivä 12.11.2013 **Kieli** Englanti

☒ **Monografia** ☐ **Yhdistelmäväitöskirja (yhteenveto-osa + erillisartikkelit)**

Tiivistelmä

Yhteiskunta, maailmantalous ja sähkövoimajärjestelmä ovat syvällisesti liitoksissa toisiinsa. Muutos yhdellä alueella vaikuttaa koko systeemissä. Tämä väitöskirja on tutkimusmatka sähkönjakeluverkosta maailmantalouteen, tarkentaen päämuuntajien omaisuuden hallintaan.
Väitöstutkimuksen tavoitteena on kehittää sähkönjakeluverkon dynaamista skenaariomallinnusta omaisuuden hallinnassa sekä soveltaa kehitettyä mallia verkkoyhtiön päämuuntajaomaisuuteen.

Sähköverkkojen omaisuuden hallinta on suoraan kytköksissä maailmantalouteen sekä paikallisen talouden muuttujiin. Muutokset taloudessa vaikuttavat sähköverkkojen omaisuuden hallintaan monesta suunnasta yhtäaikaisesti: sähkön kysyntään, verkon laajentumiseen, materiaali- ja laitteistohintoihin sekä operatiivisiin ja rakentamiskustannuksiin.

Työssä muodostettua omaisuuden hallinnan kustannusfunktiota hyödynnetään analysoimalla omaisuuden hallinnan kokonaisvaikutuksia eri maailmantalouden skenaarioissa. Teknillis-taloudellisten riippuvuuksien mallintaminen on tarpeellista erikoisesti turbulenteissa taloustilanteissa ja niihin varautumisessa. Tämä väitöstyö esittelee tavan arvioida teknillis-taloudellisia yhteyksiä sähköverkkojen omaisuuden hallinnassa ja tarkentaa ymmärrystä päätösten seurauksista maailmantalouden kehityskuluissa. Alati muuttuvan omaisuuden hallinnan ja kokonaiskustannusten välisten riippuvuuksien ymmärtäminen on erikoisen tärkeää tavoiteltaessa taloudellista tuottoa ja operatiivista tehokkuutta.

Avainsanat Omaisuuden hallinta, Skenaariomallinnus, Tehomuuntajat, Sähköverkot

ISBN (painettu) 978-952-60-5538-1 **ISBN (pdf)** 978-952-60-5539-8

ISSN-L 1799-4934 **ISSN (painettu)** 1799-4934 **ISSN (pdf)** 1799-4942

Julkaisupaikka Helsinki **Painopaikka** Helsinki **Vuosi** 2014

Sivumäärä 210 **urn** http://urn.fi/URN:ISBN:978-952-60-5539-8

CONTRIBUTION OF THE AUTHOR

The author has developed the methodology presented and used in the analyses and made all the analyses himself. The results and conclusions are the sole work of the author.

FRONT COVER PICTURE APPLIED

The front page picture of our beautiful Earth is taken by the NASA Apollo 17 crew from expedition to the moon at the distance of about 45 000 kilometres from Earth in the year 1972. National Aeronautics and Space Administration, NASA, United States, Image identification AS17-148-22727

ACKNOWLEDGEMENTS

The pursuit of the highest goals in any particular field leads to individual development pressure that can ennoble one due to the demanding refining process. This intense achievement environment brings naturally forth the questions of life in general and the individual and communal positioning in it. I am thankful to my supervising Professor Matti Lehtonen who has truly aided me with these tangible and influential insights in life in general besides fruitful supervision in the field of science.

The knowledge at the highest levels can only be achieved by following the fundamental path of cooperation between the master and the apprentice. I am highly grateful to my Master and friend, Dr. Markku Hyvärinen who has inspired in all the levels of this journey to achieve great results, and who has undoubtedly lead me into a new level of knowledge in the field more than ten years ago. I am proud to realise that my Master is among the highest ranking professionals in the field of electricity distribution and especially in leading others to new frontiers of knowledge.

An upscale target has a significant attractive force among the people who work near the same expertise area. Praises go to Dr. John Millar who has given a lot in terms of professional discussions and in fine tuning the manuscript. Profound acknowledgement goes to Professor Josu Takala and Professor Mehdi Vakilian for their in-depth commentaries which have given these pages the silver lining of world class knowledge in the field and also to Dr. Dejan Susa for accepting the task of dissertation opponent. Also, I would like to thank Mr. Martti Malmivirta and Dr. Markku Luoma for mind-opening discussions about the philosophical frames of this dissertation.

Highest organisational gratitude goes to Helen Electricity Network Ltd. and Helsinki Energy and their respective directorship of Risto Harjanne, Markku Hyvärinen, Jouni Lehtinen, Mauri Vatanen, Jari Lintuvuori, Jyrki Nieminen, Oskari Patjas, Osmo Siirto and Markus Lehtonen, Kauno Kaija, Jarmo Karjalainen, Martti Hyvönen and Pekka Manninen.

There are essential reasons to give thanks for warm collaboration in doctoral studies to Professor Lina Bertling Tjernberg and Professor Lars Nordström from KTH Royal Institute of Technology and Dr. Arjan van Schijndel from Eindhoven University of Technology and to Dr. Hasse Nordman and Mr. Timo Tuomisto from ABB.

Significant successes are built on cooperation, and great challenges can only be overcome with versatile support of the society and eventually the individuals who form it. Thank you all, for you have been my support in this success.

HALL OF GRATITUDE

My utmost gratitude for all the people who have made this long-term pursuit possible and aided me in conducting this doctoral dissertation journey to this successful conclusion,

The Friends, The Colleagues and The Inspirers

Esa Saarinen
Elias Pöyry
Aki Toivanen
Jarmo Partanen
Veikka Pirhonen
Olli Markkanen
Sami Sailo
Jaakko Aho
Matti Vaattovaara
Sirpa Savolainen
Raija Leonoff
Jaakko Juusti *(in memoriam)*
Mika Hinkkanen
Juha Stenberg
Juhani Pelkonen
Juha Sipola
Per Lindell
Pekka Sihvonen
Jouni Pylvänäinen
Juhani Palttala
Jouko Pitkänen
Nie Pin
Niemelä family
Henry E. L. Pohan
Vellu Salminen
Antti Jääskeläinen
Tommi Kujanpää
Kirsti Pätsi
Pekka Malinen
Antti Räty
Pirkko Marttila
Osmo Rautava *(in memoriam)*
Rauna Lappalainen
Matti Rae
Jukka Kasslin
Kimmo Lindholm
Martti Korkiakoski
Markku Antikainen
Jouni and Laura Riuttanen
Hakala brothers
Markku Suvanto
Harjula family
Kimmo Tyni
Mika Loukkalahti
Pirjo Heine
Toivo Kuosmanen
Ville Yliaska
Hursti family
Tervahauta family
Joonatan and Elina Rautio

The Societies

Helen Electricity Network Ltd. and Helsinki Energy
Executive MBA 2011 Alums, Aalto University
Aalto University Guilt of The Cross
Pentecostal and Evangelical Free Churches in Sodankylä
Lutheran Congregations in Otaniemi and in Sodankylä
Saalem Church in Helsinki
The Circle of Friends of Vichy Water

The Family

Sini Palola
Erkki and Eila Palola
Paulus, Henriika and Eeva-Marja Palola
Tuomas, Ruth, Iida, Tilda, Salli and Eeli Palola
Markku and Pirjo Luoma
Irina, Jan-Sebastian, Fransina and Vendela Renman

Sincerely,

Jussi Palola

in Helsinki, Finland, 6th of January 2014

TABLE OF CONTENTS

LIST OF SYMBOLS

C_{CBM}	Costs of condition based maintenance
C_{CIC}	Cost of interruptions to customers
C_{CIC_PT}	Cost of interruption to customers due to power transformer failure
C_{CM}	Costs of corrective maintenance
C_{CM_FO}	Costs for corrective maintenance of forced outage cases
C_{CM_SF}	Costs for corrective maintenance in serious failure cases (€)
C_{MOH}	Power transformer major overhaul expenses
C_{OLD}	Power transformer on-line diagnostic equipment investments cost
C_{PM}	Costs of preventive maintenance
C_{PM_SF}	Costs of preventive maintenance for serious faults
C_{PM_fault}	Costs of preventive maintenance for faults
C_{PT}	Power transformer investment cost
C_{TBM}	Costs of time based maintenance
$C_{TSOfeeOther}$	TSO grid fee for other time consumption
C_{TSOfeePT}	Balanced TSO grid fee for PT loss load profile
$C_{TSOfeeWinter}$	TSO grid fee for winter time consumption
$C_{TSOtransfer}$	TSO transfer cost for DSO
C_{TransMC}	Yearly marginal cost for building the power loss transferring capacity
C_{capex}	Capital expenses
$C_{capex\_PT}(y)$	Power transformer unit capital expenses in the year y
C_{mainex}	Maintenance expenses
C_{opex}	Operational expenses
C_{qualex}	Quality expenses
$C_{qualex\_PT}(y)$	Expected yearly quality cost of power transformer in the year y
$C_{special}$	Power transformer special installation expenses
$C_{support}$	Costs of maintenance support systems, spare parts, warehouse
C_{total}	Total expenses
c_x	Cost of one hour interruption for customer type x, where r=residential, c=commercial, i=industrial, a=agricultural, p=public
CRC_{Trans}	Current replacement cost of the 110 kV subtransmission network
$E_{LoadLossPT}(y)$	Yearly load loss energy for unit PT in the year y
$E_{LossOtherPT}$	Power Transformer energy losses at another time
$E_{LossYearPT}$	Power Transformer energy losses in the year
$E_{LossWinterPT}$	Power Transformer energy losses in winter time
$E_{NoLoadLossPT}(y)$	No-load loss energy for unit PT in hour h in the year y
$ENS(t_{\mathrm{int}})$	Energy not supplied due to the interruption
$f_{MOH}(t_{MOH})$	Fault rate reduction factor after the major overhaul time t_{MOH}
$f_{OLD}(y)$	OLD investment price relation factor in the year y

$f_{CIC_{public}}$	CIC-unit multiplier for public customers
$f_{CIC_{RCI}}$	CIC-unit multiplier for residential, commercial and industrial customers
f_{Cu}	Subsystem price relation factor for copper price
$f_{LoadPT}\ (y_0)$	Load growth factor for the first simulation year y_0
$f_{LoadShape}(y)$	Energy price factor for load losses due to the shape of consumption distribution in the year y
$f_{NoLoadShape}(y)$	Energy price factor for no-load losses due to the shape of consumption distribution in the year y
f_{Oil}	Subsystem unit price relation factor for oil
f_{St}	Subsystem price relation factor for steel price
$f_{cons(x)}$	Construction cost relation to whole subsystem x investment
$f_{eLoadPT}\ (y)$	Power transformer Load growth factor for the year y
$f_{eLoadST}\ (y)$	Substation load growth factor for the year y
$f_{lab(x)}$	Labour cost relation to whole subsystem x investment
$f_{mat(x,m)}$	Cost involvement factor for manufacturing material m for subsystem x
$f_{special}(t)$	Price relation factor for special installations in the year t
f_{x_cons}	MOH and special installation price relation factor for construction cost index
f_{x_lab}	PT, MOH or OLD price factor for labour costs
f_{x_pro}	PT, MOH or OLD price factor for producer price index
$i_{cic}(t)$	Cost of interruption development index in year t
$i_{cons}(t)$	Construction price index value in the year t
$i_{energy}(t)$	Energy price index development with time
$i_{lab}(t)$	Labour cost index value in the year t
$i_{mat(m)}(t)$	Nominal material m price index value in the year t
$i_x(t)$	Price relation indices development with time for different cost elements, such as construction or labour costs
P_{LoadN}	Power Transformer nominal load losses
$P_{NoLoad\ N}$	Power transformer no-load losses at the nominal voltage
$P_{eSummerPT}\ (y)$	Power transformer summer peak load in the year y
$P_{eW\,\mathrm{int}\,erPT}\ (y)$	Power transformer winter peak load in the year y
$P_{\mathrm{int}\,errupted}$	Interrupted electric power supply
$\hat{P}_{TransformerLoss}$	Peak power for the losses of the power transformer
$P_{TransCapac\ ity}$	Transmission capacity of the 110 kV subtransmission network
$p_{MOH}(t)$	Major overhaul price relation factor in the year t
$p_{LoadLossE}(y)$	Load loss energy price in the specific year y
$p_{NoLoadLossE}(y)$	No-load loss energy price in the specific year y
$p_{energy}(t)$	Energy price as function of time
$p_{system}(y)$	Yearly energy system price in the year y
$p_{ss(x)}(t_0)$	Present day price for a certain subsystem x investment
$\overline{p}_{daily_{PT}}$	Annual average for daytime peak power for the power transformer unit
$PT_{ON\_OFF}(y,h)$	Boolean value whether power transformer is in operation or not during the hour h in the year y
r	Rate of interest

S_N	Rated power of the transformer
$S(h)$	Transformer loading for hour h in the year
$s_{network}(t)$	Network loading as a function of time
s_x	Share of the power demand for customer type x, where r=residential, c=commercial, i=industrial, a=agricultural, p=public
t	Time
t_{FO}	Interruption time of power transformer forced outage
t_{SF}	Interruption time of power transformer serious failure
t_{int}	Duration of interruption h
$t_{lifetime}$	Economic lifetime of the subtransmission network
Q	Unreliability of the system
$Q_{PT}(y)$	Power transformer unreliability in the year y
$R_{PT}(y)$	Power transformer reliability in the operation year y
$\mathrm{X}_{PT}(y)$	Power transformer loading criticality valuation for one hour interruption in the year y

α_{F_x}	Share of the forced outage failures with maintenance program x
α_{SF_x}	Share of the serious failures with maintenance program x
β_{PM_SF}	Preventive maintenance serious fault detection rate
β_{PM_fault}	Preventive maintenance fault detection rate
β_{x_F}	Preventive maintenance share for minor faults with maintenance x
β_{x_SF}	Preventive maintenance share for serious faults with maintenance x
$\Delta c_{gridfee}$	Changes in the National TSO grid fees due to investment
$\Delta c_{personnel}$	Changes in the personnel costs due to investment
$\Delta z_{network}$	Network impedance changes due to investment
λ_{FO}	Rate for power transformer failures
λ_{FO_PT}	Yearly forced outage rate of the power transformer
$\lambda_{PT_F}(\mathrm{y})$	Power transformer failure rates that lead to interruption in the year y
$\lambda_{PT_{SF}}(\mathrm{y})$	Power transformer serious failure rate that lead to interruption in the year y
λ_{SF}	Rate for serious power transformer failures
λ_{SF_PT}	Annual serious failure rate of the power transformer
λ_{base}	Power transformer incipient fault rate base line function
λ_{system}	Annual failure rate of the system
ρ_F	Prevented failures rate with applied maintenance strategy
ρ_{SF}	Prevented serious failures rate with applied maintenance strategy

LIST OF ABBREVIATIONS

AM	Asset Management
CBM	Condition-based maintenance
CIC	Customer Interruption Costs
CIS	Communication and Information System
CMMS	Computerised Maintenance Management System
DP	Degree of polymerisation value for power transformer insulation paper (approximately 1200 when paper is new)
DSO	Distribution System Operator
EAM	Enterprise Asset Management, A system to manage the network maintenance processes within a company to ensure equipment availability and to reduce asset downtime.
ECB	European Central Bank
EMA	Electricity Market Authority
GIS	Geographic Information System
ICT	Information and Communications Technology
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
KBAI	Knowledge Based Asset Integrity
OECD	The Organisation for Economic Co-operation and Development
OLD	Online Diagnostics
OMS	Operations Management Support
PT	Power Transformer
RCM	Reliability Centered Maintenance
SCADA	Supervisory Control and Data Acquisition, Control system used for gathering data in real time from remote network locations in order to control equipment and conditions.
SCM	Service Configuration Manager
SPI	System Performance Index
TBM	Time-based maintenance
TSO	Transmission System Operator
WACC	Weighted Average Cost of Capital
WB	The World Bank

1 Introduction

The life of individuals, welfare of societies and global economics are deeply interconnected to power systems in a multidimensional manner. Change in one entity affects the whole system. This thesis is a research journey from electrical distribution systems to global economics and finally to power transformer unit asset management. The objective is to investigate dynamic scenario modelling in power system asset management and apply it to a distribution system operator's power transformer asset base.

1.1 Research Domain

The electrical energy sector has developed from small local islands to a conglomerate of highly integrated complex energy systems within a hundred years. Business structures have developed as the importance of electricity systems has increased and there has been considerable technical development in the energy and information & communication sectors. The latest significant structural business legislation event in Finland was the deregulation of the electricity energy markets in 1995. Electricity generation, transmission & distribution and retail were segregated to increase competition in the market. As a result, the transmission and distribution businesses are regarded as natural monopolies regulated by the government's energy market authority.

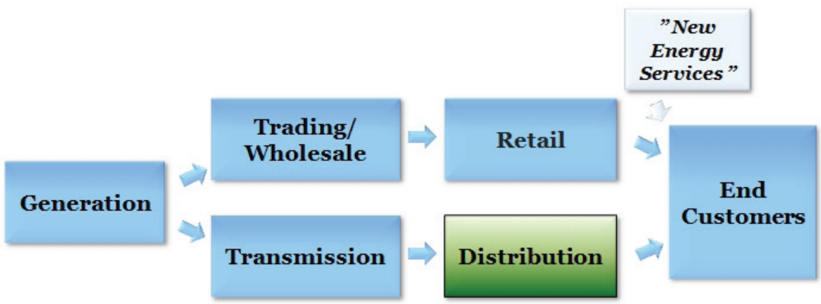


Figure 1-1 Current electricity industry value chain highlighting the part this thesis concentrates on: developing the Distribution System Operator's asset management. /1 applied/

The complexity of the long-term energy policy solution is vast and every inhabitant on this planet is dependent on and affected by energy systems, not least when concerning emissions and relations to global economy and health. Due to the global size of the dilemma, change happens continuously, but when energy policy is altered the whole value chain is affected and policy changes can transform large scale business segments. For example, the increasing energy efficiency demand in traffic is leading to new demand for electricity for electric vehicles, and distribution networks need to respond to this increasing demand. Another development is the rising of a new energy business segment along with local small-scale energy production, energy related home automation and electric mobility. Global economic cycles, energy policies and the energy business sector are bonded together. This is especially true from the asset management perspective in power system operations. Our economic environment has changed along with globalisation and this adds significant challenge in asset management decision-making. /2/

> "The fact is that we are entering a new age, The Age of Turbulence. - Turbulence is the new normality, punctuated by periodic and intermittent spurts of prosperity and downturn—including extended downturns amounting to recession, or even depression. And turbulence has two major effects. One is vulnerability, against which companies need defensive armour. The other is opportunity, which needs to be exploited. Bad times are bad for many and good for some. " Philip Kotler and John A. Caslione /3/

Power system asset management involves balancing multiple objectives and deals with the question of comprehensive long-term solutions for the desired service target within a changing environment. This thesis aims to enhance power system asset management decision-analysis by linking technical electrical network planning with the global economic dependencies. For techno-economic solutions both sides of the dilemma need to be handled together, because complex relations from technical designs affect economic performance and vice versa. A one-sided, purely technical analysis cannot reach the required accuracy in a turbulent global environment.

The thesis concentrates on asset management analysis with dynamic scenario modelling utilising probabilistic methods. The main aim is to investigate dynamic scenario modelling in the power system asset management environment and to apply it as a case example to a DSO's power transformer assets. The motivation is to enhance better utilisation of the assets within a changing economic operation environment, and also to produce an insightful analysis for electricity distribution system asset management decision-making. This thesis combines three central asset management aspects in the dynamic scenario modelling:

Current and future societal demand for the electrical network

Community planning creates the essential background information for the future requirements for the electrical network. Especially sub-transmission systems require space, which creates the demand for co-operative long-term community planning with city administrators.

Technical aspect of power system asset management

An electrical network is a geographically widely spread complex technical construction which comprises numerous components and subsystems. Knowledge about the network properties and condition forms a backbone for timely investment decision-making.

Global economic effects on power system asset management

Global economic trends significantly affect energy consumption and the pressure to invest. The electrical transmission and distribution network business is physically asset intensive: Finland's distribution network current replacement cost is in the scale of billions of Euros, and is ultimately linked to building cost indices and global commodities such as copper and aluminium. Despite the noticeable dependencies between the global economy and electrical network, investments are planned solely from a technical requirement perspective, whereas evaluations in terms of economic trends are somewhat ignored. Right timing can save a lot of money without endangering the primary distribution system operator mission: reliable and effective electricity distribution. In some of the best cases reliability benefit and investment cost reduction can both be achieved, for example when applying modern online condition management technology.

1.2 Electricity Distribution System Interest Groups

There are several interest groups around the electrical transmission and distribution business and associated physical facilities; therefore the demands are also multidimensional. For instance, elements such as high service quality along with environmental protection and minimisation of economic metrics drive actions in different directions and the asset manager has to construct a solution to this challenge. Central aims in asset management are enhancing quality of service, reducing costs in service production and increasing profits for the owners. Various decision attributes are to be taken into account in asset management planning, implementation and monitoring. Figure 1-2 illustrates the main beneficiaries around the transmission and distribution business: the blue circle denotes the electrical distribution system operator's business and the arrows represent the active forces in asset management decision-making. /4/

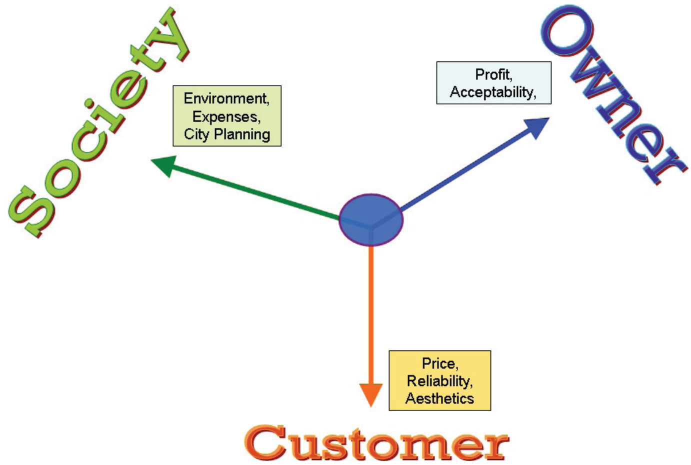


Figure 1-2 Beneficiaries around the transmission and distribution business: the arrows represent the forces which affect business decision-making. The asset manager's task is to transparently harmonise the different aspects in line with the corporate service strategy. /4/

The previous figure shows only a two-dimensional snapshot illustration from the real situation: actually the forces are more multidimensional. Even a single beneficiary has demands which push decision-making around the electrical network in exclusive directions; one of the major issues is to balance the trade-off between capital expenses and the reliability of the network. Aesthetics are also evaluated highly in urban areas, which usually mean higher expenses as well.

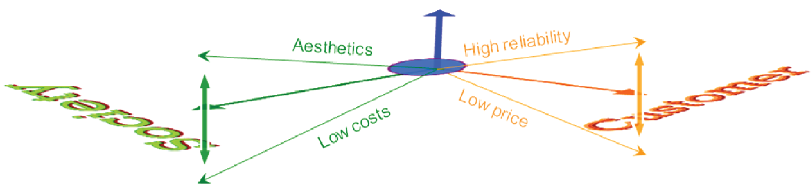


Figure 1-3 Three dimensional illustration of the multidimensional forces around asset management decision-making. /4 applied/

Electrical engineering, system analysis and applied economics are used in modelling the dynamic dependence between the essential factors in distribution system asset management. This method for dynamic scenario modelling is outlined, to enhance comprehensive and transparent decision-making in the DSO's companies.

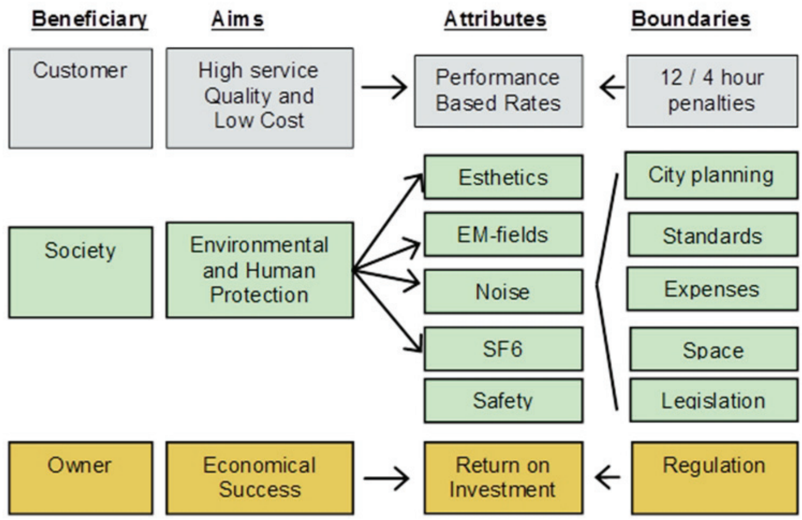


Figure 1-4 A structural example of an investment decision attributes set in terms of the aims of different interest groups and controlled by rules, legislation and resources. /4/

Many of the attributes can be linked to economic resources. For example, system performance is highly dependent on investments and operation & maintenance costs, although a system analysis is needed to make this interdependency visible. The challenge is to model all the various perspectives and to comprehend what is significant in each case. Another challenge is that we are involved with future dimensions. This means that with the information from the past and the present we must construct scenarios and analyse them with probabilistic methods. Uncertainty still remains, but a sensitivity analysis can aid in handling the risk and in understanding the possible range of change.

There is concern if the decision-maker and decision-analyst regard economics as objective science when placing certain highly subjective valuations into equations /5/. It is essential to acknowledge this dilemma, especially when qualitative aspects of distribution network service are converted into economic metrics. One of the central conversions of a qualitative attribute to economic metrics in power system asset management practice is evaluating network service reliability from the economic point of view of the customer.

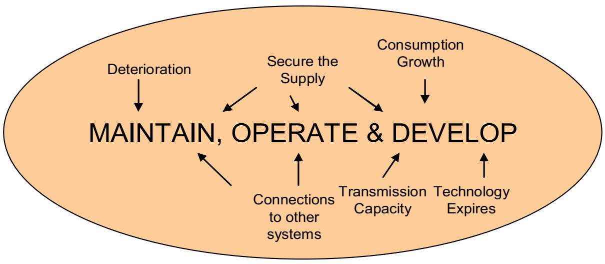
1.3 Asset Management Drivers

Electricity transmission and distribution are monopolies regulated by the Finnish Ministry of Employment and the Economy. The Finnish Energy Market Authority (EMA) is an expert organisation subordinate to the Ministry with a mission to supervise and promote the functionality of the Finnish electricity markets. EMA grants the licenses for the electricity distribution business regionally with legislative obligations that drive the DSO's asset management. The Finnish Electricity Market Act declares three principal obligations for the electricity distribution system operator (DSO): /6/ /7/

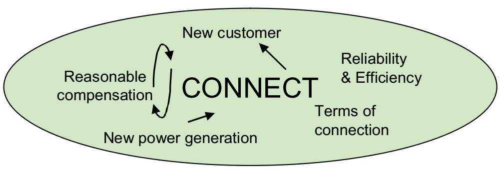
The distribution System Operator has the obligation to:

- maintain, operate and develop the electricity system
- connect consumption sites and power generation
- transmit electricity

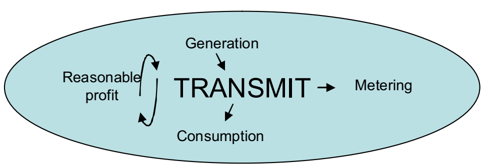
"The system operator shall **maintain, operate and develop** its electricity system and the connections to other systems in accordance with its customers' reasonable needs, and **to secure**, for its part, **the supply** of sufficiently high-standard electricity to its customers (obligation to develop the electricity system). " /6/



"On request and against **reasonable compensation**, the system operator **shall connect** to its system electricity consumption sites and power generating installations meeting the required technical specifications within its area of operation (obligation to connect). The connection conditions and **technical requirements** shall be impartial and non-discriminatory and they shall take note of the conditions of the **reliability and efficiency** of the electricity system. At the request of the subscriber, the system operator **shall give** him a comprehensive and sufficiently detailed estimate on the **subscription costs**. (1130/2003) " /6/



"The system operator shall **sell electricity transmission services against reasonable compensation** to those that need them within the limits of its system transmission capacity (obligation to transmit). " /6/



These general principles form a course of conduct for the distribution system operator. Power system asset management analysis is designed to aid decision-making concerning the performance of the general tasks of the network company. An electricity network has usually been developed over more than one hundred years and so there are a multitude of consumption load points and power generation connections in the network. Given that the network has been under construction for a long time, the development steps are founded upon previous actions and technology. An electricity distribution system which is widely spread over the environment is always influenced by nature, material deterioration, the global economy, community structuring, and the constructing and maintaining of all other infrastructures in the city.

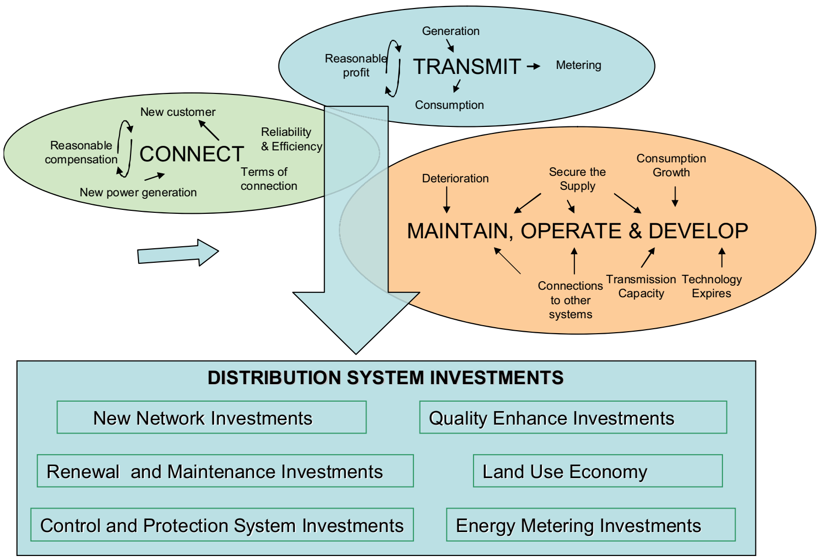


Figure 1-10 Three principal obligations for electricity distribution system operators according to the Finnish Electricity Market Act regarding electricity distribution network asset management.

The principal DSO obligations lead to a complicated investment portfolio which has many options. For example, balancing the principal obligations to maintain and develop the electricity network can be solved with a variety of renewal investment and maintenance program combinations. A complete quantitative analytical solution without any assumptions about power system investment decision-making is impossible to find as so much of the process is strongly linked to uncertain global economic development. However, one can aim to make sense of the relations and dynamics of the economic playground in question. A classical scientific way to increase understanding in research is to break down the problem into its basic parts and define the relationships between them. Such a reductionist approach usually confronts limits when trying to build a comprehensive model of the subject. The science of economics has developed methods to override the limitations of reductionist modelling with a view that tries to grasp a robust holistic overview rather than include all the details. An example of this is the use of probabilistic methods and applying the chaos theory in economics. /8/

1.4 Research Objective

The objective of this thesis is to investigate dynamic scenario modelling in power system asset management and to apply it with a case study on a distribution system operator's power transformer fleet assets. The case specific target is to enhance decision-making in power transformer[I] asset management, including investment timing and maintenance strategies.

Dynamic scenario modelling aims to make asset management more adaptive and more transparent within a changing economic and societal environment. Modelling starts from consumption forecasts and continues with future investment planning. The global material market and building trade behaviour are important factors to include in the model since the asset manager is dealing with physical assets and construction for the most part. The presented method will robustly model power transformer fleet behaviour in different asset management environment scenarios. The comprehensive cost function comprises capital, operational, maintenance and quality costs. Quality aspects are derived from network reliability from the societal point of view.

Research Boundaries

The applied philosophical approach in this thesis is concentrated on known unknowns with different development scenarios. In decision-analysis theories there is a classification of unknown unknowns, expressing that there are many relevant elements that are not taken into account in evaluations since there is no knowledge about them. The method of unknown unknowns is used, for example in the aerospace industry and in business economics. /82/ /81/

The evaluation of different psychological decision making processes and decision making biases that cause deviation from the normative process is out of the scope of this thesis. /10/ /84/ /85/

As a disclaimer: the thesis applies many different sources for the future scenario building for global economics, material prices, construction activity and electricity demand. There is a continuous need to renew and

---

[I] The DSO power transformer fleet under this case analysis are units with the 110 kV primary voltage level and the fleet is described in the Appendix 1.

update the basis of future scenarios of the asset management environment and so this thesis only presents a momentary snapshot of the information. The scenario information must be updated with the most topical information around the decision-making process.

DSO business regulation model effects and company tax planning are out of the scope of this thesis, although dynamic scenario modelling can be useful for those purposes as well. /12/

1.5 Research Design

The research design to link the applied data to the research objective is structured around five general components: research question, research proposition, unit of analysis, logical linkage from the data to proposition and interpretation criteria. The research question is how to enhance decision-analysis in electrical network asset management within a changing business environment. The research proposition is built around the observation that changes in the global economy have significantly greater effects than generally applied electrical engineering focused asset management approach can take into account. The thesis proposition is to combine global economy, societal development aspects and electricity distribution system asset management into dynamic scenario modelling to compose a decision-analysis which is applicable in the turbulent business environment. In the specific case described in this dissertation, the unit of analysis is DSO power transformer asset management cost, and the research is designed to model comprehensive costs to be applicable in power transformer fleet asset management scenario analysis. /13/

Asset Management Logics, Criteria and Goals

The applied data is collected with a research question and proposition in mind to aid decision-making with dynamic scenario analysis. Many different information sources for electrical system modelling, global economy dynamics and society development are used and presented step-by-step in the work. In essence, decision-analysis logic is built on three fundamentals: decision goals, alternative options and selection criteria. Decision-analysis in asset management requires a wide range of decision strategies and corresponding selection criteria in different phases of the process. The backbone of electrical network asset management is in heuristic principles from the discipline of electrical engineering, in terms of understanding, describing and ensuring the functionality of the system. Standards and legislation lay down an important foundation for local electrical network design and properties, as they provide representative rules and boundaries. In decision-making, standards are pre-decisions, and are needed only to ensure that all requirements are fulfilled. An empirical approach is required as an adjusting loop from experiences of the system performance, and also when estimating future performance based on historical data. /9/ /10/ /13/

After the engineering principles of functionality and normative boundaries are met, there is still a wide range of possible alternative solutions. Rational goal setting is used to finalise the decision-analysis. A historically preferred approach is to minimise present day capital costs once standards and legislative boundaries are met, but when operational life-cycle costs and quality costs present a large part of the overall costs in asset management there is a need for a more long-term approach. A decision goal which takes into account several cost and benefit factors over the life-cycle is required. After the technical and societal quality requirements are met, variable quality costs and benefits mainly concern the reliability of the distribution services in network asset management. Reliability aspects can be measured with the availability of the service and converted to economic benefits or costs based on the cost of interruption to customers. Interpretive conversions of reliability indices to economic metrics enable single attribute analysis, hence all other costs, whether they be labour, investment, energy losses, materials, effort or real estate, can be expressed through monetary terms. /9/

When standards and legislation ensure the health and safety aspects of the electrical network and city zoning define structural and aesthetical boundaries, then a multi-attribute analysis can be functionally converted into a single attribute analysis. Then the decision goal is to minimise the total costs, which include: capital costs, operational costs, maintenance costs and the quality costs from the customers' point of view. /9/

1.6 Methodology and Structure of the Work

The methodology is built around equations that represent network asset management related costs and are simulated with different initial future development scenario data. Methodological mode of thinking and acting is consultative and is comprised with the systems approach. The work is documented with linear-analytic structure starting from the description of the research domain and objective in this chapter. The second chapter reviews essential international asset management concepts and research around the dissertation topic. The comprehensive cost functions for electrical network asset management presented in the third chapter determine the system causality and are programmed in an excel routine for the simulations. The data for the initial values in the future simulations are important. Table 1-5 gives the sources that are used for initial scenario data in the simulations. /13/ /14/

General groundwork scenarios for network asset management are presented in Chapter four and more case specific power transformer asset management scenarios are presented in Chapter five. The computer simulation routine is programmed in Microsoft Excel visual basic. Dynamic scenario simulation results are shown in Chapter six and overall conclusions of the dissertation in Chapter seven.

Table 1-5 Essential data sources for the dynamic asset management environment simulation.

MARKET DYNAMICS	*[Chapter 4]*
World Bank - Global Economic Prospects	*/67/*
Statistics Finland information	*/89/ /91/*
OECD statistics	*/90/*
Finnish Business and Policy Forum EVA	*/76/*
ELECTRICITY CONSUMPTION DEVELOPMENT	*[Chapter 4.3]*
Helsinki city zoning master plan 2030	*[chpt. 4.3.1]*
Characteristic consumption development scenarios	*[chpt. 4.3.2]*
Helsinki city construction statistics	*[chpt. 4.3]*
RELIABILITY MODEL	*[Chapter 5]*
CIGRE fault statistics and guides	*/51/ /35/ /59/*
Finnish fault survey statistics by Fortum	*/87/*
French survey statistics - RWE	*/65/*
Diagnostic survey in Helen Electricity Network Ltd	*[chpt. 5.7]*
DSO's NETWORK PROPERTIES FOR MODELING (HELEN)	*[Chapter 5]*
DSO power transformer fleet in focus	*[chpt. 5.2]*
Fingrid (National TSO) commercial conditions for DSO	*[chpt. 3.4]*
DSO power transformer fleet purchases information	*[chpt. 5.5]*
DSO power transformer customer distribution information	*[Appendix 1]*
COST OF INTERRUPTIONS TO CUSTOMERS	*[Chapter 3.6.1]*
Finnish research results 1979-2005	*/36/*

Dynamic scenario modelling is a continuous long-term process and data needs to be updated at least on a yearly basis. Besides the straightforward application of updated data, the new information can also be used to revise and validate the systemic model as well.

1.7 Contribution

The environment for power system asset management is continuously changing. Global economic shifts make up a significant part of the overall costs in the asset management of electrical networks. Electrical parameters are carefully calculated in the distribution system operator's decision-making while global economic price developments are valuated with a single constant. This thesis investigates the possibilities and benefits of combining a classical power system analysis with global economic scenarios in an asset management comprehensive cost analysis. This thesis applies the findings of many equipment condition monitoring professionals from manufactures, academic researchers and specialists in the energy companies.

Figure 1-11 Thesis approach: the asset manager's dilemma of combining four approaches in dynamic scenario modelling: Global economic scenarios, theory of electrical systems and reliability, maintenance diagnostics and expert knowledge.

The main contributions are in presenting a methodology for combining global economic scenarios with electricity distribution system asset management and in presenting a practical application of the dynamic scenario modelling with a case study of a distribution system operator's power transformer fleet assets. The contribution is not only in the analytical and empirical modelling, but in combining a wide and diverse range of inputs to deliver a practical outcome that is applicable in power transformer asset management right away.

2 Asset Management Concepts and Research

Seeking more from less has been practised for a long time in human history. This chapter presents the basis of the asset management concept in electrical networks and specific tools for condition assessment and maintenance applied in network asset management. Dynamic scenario modelling is built on electrical engineering, system analysis, component life-cycle research and applied economics.

2.1 Evolving Asset Management Thinking

Asset management has existed as a background philosophy as long as there has been the idea to seek the highest benefit from the limited resources available. A structured view on asset management has developed along with the research of physical sciences and in the business sector, especially alongside scientific management development in the 20th century. The more society has faced limitations from lessening resources compared with demand, the more effort has been directed on enhancing the useful output from less input. For example, in Finland during the Second World War and later on due to the payment of war reparations, the industry was forced to make more from less in order to survive. During that period scientific management was applied to maximise the usage of valuable resources. Asset management continues the heritage of scientific management and international research efforts have accelerated along with the ageing of vital infrastructure in western countries and new investments in emerging countries on a massive scale. /41/ /57/

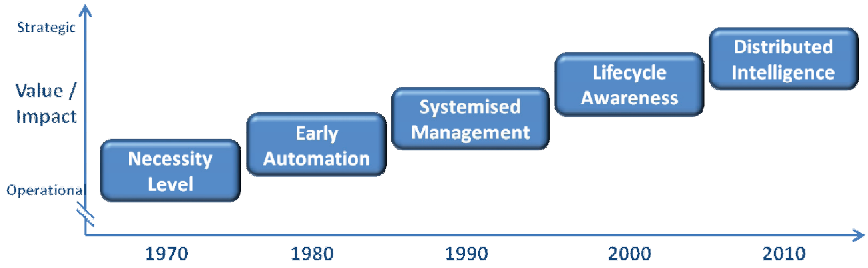


Figure 2-1 Evolution of corporal asset management thinking in the recent decades. /60 Applied/

Asset management thinking has gradually been upgraded from the operational "floor" level maintenance actions with relations to strategic asset portfolio management and dynamic strategic planning[1]. Early automation rapidly increased operational efficiency and development steps later on have increasingly connected asset performance with organisation strategic targets in a systemised and quantitative way. Increased efficiency requirements and rapid structural changes in businesses have lead to thinking about asset portfolio lifecycles. This development is ongoing, especially now with the addition of distributed automation and diagnostic intelligence to asset systems. Network asset management is aligned with this general development path when more ICT components are added for more accurate operations and asset performance. /60/

2.2 Traditional Thinking in Network Asset Management

Traditional investment processes have been driven by the standards and ensured by reasonably flexible budgets. Clear simplified rules enabled functional daily planning with limited computational needs. Reliability evaluations were performed with deterministic principles such as the n-x criterion. To make a long story short: a desirable service target was assured by adhering to robust technical criteria and economic evaluations were based on single-attribute minimisation such as investment costs. /9/

The traditional planning cycle begins with forecasting the peak load development in the network area. The next step is to evaluate the peak load distribution for all systems in order to find if the network can handle the situation with a deterministic reliability analysis. A case study plan is made to fix the problem if any deviation from these standards is found.

---

[1] Richard de Neufville, ***Dynamic Strategic Planning for Technology Policy***, Technology and Policy Program, Massachusetts Institute of Technology

Alternative actions are ranked with choosing the option with the lowest investment for the fix. /9/

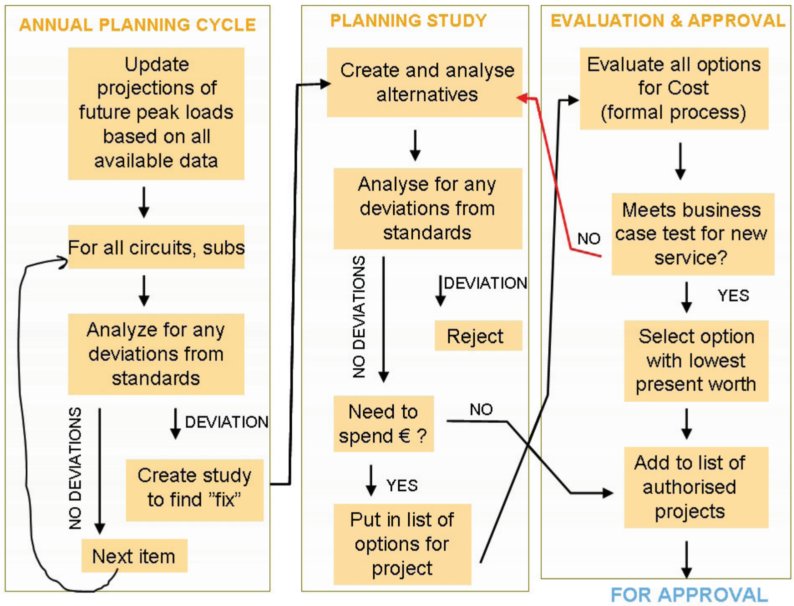


Figure 2-2 The traditional standards-driven, project-oriented least cost process described by H. Lee Willis. /9/

Network asset management has been affected by efficiency-thinking, which has been increasing throughout society over the last decades. Accordingly, the benefit-cost ratio was developed to prioritise optional investments only if the benefits outweigh the expenses. This work will also take different future scenarios into account in the analysis. Historically deterministic decision-making has been the practice in network investment planning to a great extent. A deterministic analysis does not have high computational demands: decisions are based on a simple time-relation, and are ensured by a flexible and sufficient budget. It is practical and easy to use, but at the same time the simplified models leave essential options out. Budget flexibility is also narrowing as the business frame is and is still changing around electricity distribution companies.

Gradually, theories from business finance, such as real option theories, are being applied in electrical distribution systems expansion planning and maintenance management as well. The theory assesses real capital investment options in sense of timing and expansion. The first publications of real option theory were published around 1984. /31/ /42/ /44/

2.3 Defining Asset Management

The various definitions for asset management vary, depending on which perspective the philosophy is applied. A single business unit can see asset management as a strategy which aims to balance performance, risk and cost, for example, balancing network investments with system reliability. Corporate management can see it as handling the dilemma of which companies to buy or sell. One example of that is a shift in the car industry: for a car manufacturer nowadays it is relevant to own battery manufacturing industry because the importance of battery technology is increasing due to electric vehicles[I]. /39/ /15/ /43/

One other example of corporate asset management from the energy sector is the privatising of municipal owned energy companies. For example, in 2006 Espoo city in Finland sold[II] its municipal-owned company to a large international energy corporate and invested the funds through portfolio management services. One essential driver for privatisation[III] is the idea that fund management is a more applicable form of asset management compared to running a city-border-limited energy utility.

The research scope is wide in power system asset management and an increasing number of publications have been written in recent years. A significant number of the publications deals with the asset management concept and some specific subsystem condition asset management. /15/ /17/ /18/ /21/ /25/ /57/

[I] Kariatsumari Kouji, Nissan, **NEC Form Li-Ion Battery Company**, article in Nikkei Electronics Asia on 26.7.2007, downloaded 17.10.2009, http://techon.nikkeibp.co.jp/article/HONSHI/20070726/136836/

[II] **Espoon Sähkö, Fortum, E.on** in Finnish Wikipedia

[III] Arola Heikki, Helsingin Sanomat newspaper article, **Reduced Stock Prices Lowered Millions the Value of Espoo City Portfolio**, in Finnish: "Kurssilasku söi miljoonia Espoon sähkörahastosta", 5.9.2008

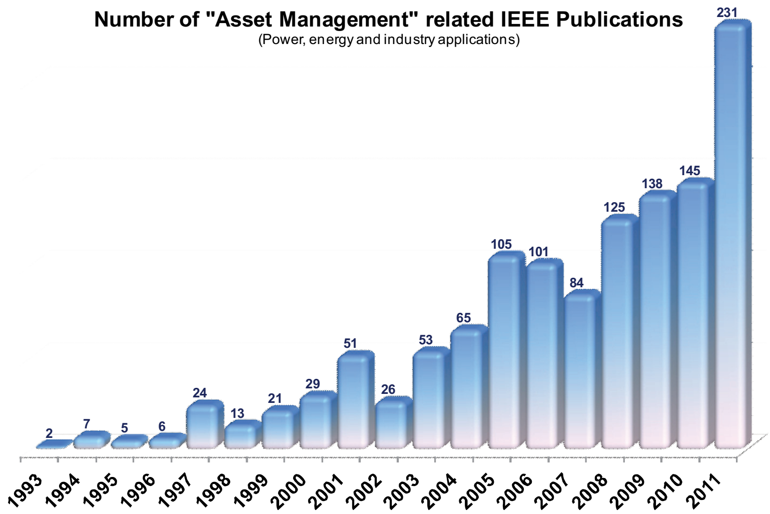


Figure 2-3 Number of asset management publications in IEEE (Institute of Electrical and Electronics Engineers) Power, Energy and Industry Applications database. IEEE published in the year 2009 approximately one third of the World's technical literature in electrical engineering, computer science and electronics (query date 2.7.2012). /57/

A versatile and up to date definition for asset management can be found from the most recent standard by the British Standards Institution (BSI) PAS 55:

> "Asset management is systematic and coordinated activities and practices through which an organization optimally and sustainably manages its assets and asset systems, their associated performance, risks and expenditures over their life cycles for the purpose of achieving its organizational strategic plan" /39/

Asset management is divided into subgroups from top-down: /40/

- ❖ **Corporate level** (corporate ownership portfolio of different companies)
- ❖ **Asset portfolio** (diverse portfolios like DSO's entire assets)
- ❖ **Asset systems** (complex functional systems such as sub transmission network)
- ❖ **Assets** (equipment items or components such as power transformers)

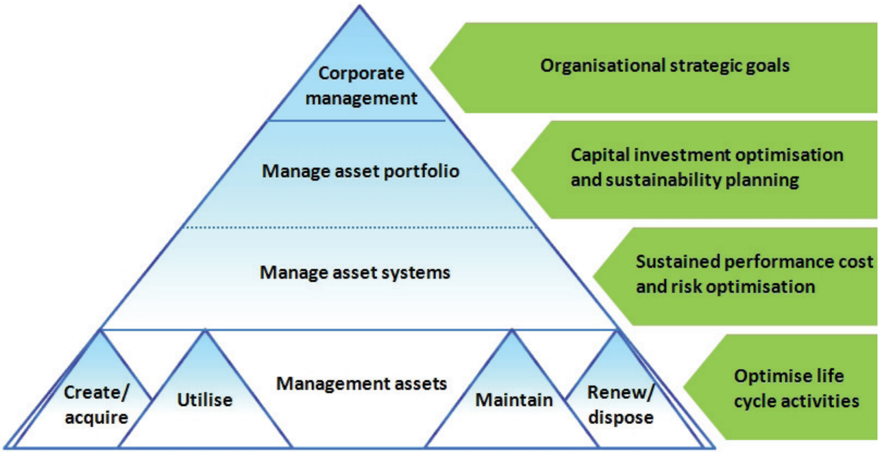


Figure 2-4 Asset management frames according to PAS 55 standard. /39/ /40/

The typical priorities of asset management in corporate management concentrate on the ownership portfolio of companies and organisational strategic goals. Although the corporate ownership portfolio perspective is not in the focus of this thesis, the dynamic investment scenarios presented later on can be an aid in business action decision analysis. In general, decision analysis aims to reveal the possible consiquences of a certain decision or strategy within the applied future scenario. At the corporate management level, strategical goals usually define the frame for decision-making in the asset management as well. /39/

Here is one example how a strategic goal is attached to asset management step by step.

One strategic goal from a multidisiplinary energy corporate which owns several companies with different asset portfolios, such as various power plants, electrical networks, distric heat and cooling generation and distribution facilities [I]:

> " Our customers and other interest groups have confidence in our operations and operations are based on good security of supply, excellent service and high quality."

High level initiatives at the corporate level are usually qualitatively indicative because goals are applied to various asset portfolios and therefore it is not reasonable to define a detailed goal. The more strategic goals approach the level where asset management is performed in practice, the more quantitative it will become. A corporate owner and

[I] Helen Group Strategy 2009; Strategy and the Values of Helsinki Energy asset portfolio manager needs to deepen the conversation in order to specify quantitative objectives.

A strategic goal within a subsidiary company which is applied to a consistent asset portfolio [I]:

> “ We aim for a considerable improvement in the reliability of the electrical network and betterment of the service level.”

“The considerable” adjective is one step from a qualitative to a quantitative and measurable goal. From that follows the practice of network planning where the goal should be clear and quantitative. A network development unit forms corporate high level initiatives into a measurable variable [II]:

> “ The target is to halve electricity supply system average interruption duration within the next five years.”

The idea is that the qualitative corporate level goal has to be attached to measurable performance rates. Setting up and sustaining this system of scientific management requires the regenerative coupling of abstract ideas with the predicted properties of the planned future investments. Revealing the relation between a qualitative idea and a quantitative goal and network planning with measurable performance rates is the challenge for transparent asset management. Several analytical tools are needed, often with a high degree of simplification. The more detailed the analytical approach, the more attention is narrowed into small separate islands of the whole asset management challenge. Also, when a more comprehensive view is applied in asset management optimisation, influential characteristics may be inadvertently omitted. This challenge is always present when defining an asset management framework.

Organisations should develop the criteria for investment and action optimisation from strategic goals through a top down approach. Simultaneously a practical evaluation should be implemented in a bottom up approach: starting the optimisation of certain tasks and interventions from equipment and minor entities, continuing with the life cycle activities for whole asset system and eventually multiple activities across multiple asset portfolios. The following figure shows three typical asset management intervention optimisation types in an asset portfolio according to the British Standard Institution (PAS 55). /40/

[I] Helen Electricity Network Ltd, Strategic Goals 2008 in Helen Electricity Network Ltd.

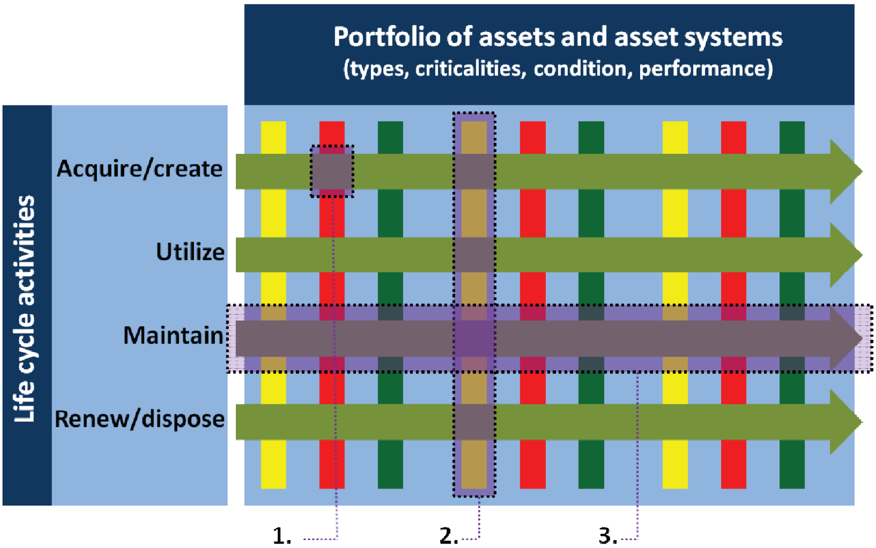


Figure 2-5 Typical asset management interventions: vertical boxes denotes certain asset (e.g. power transformers), - Horizontal green arrows denotes certain life cycle activity (e.g. company maintenance program for all assets). /40/

1. **Specific Intervention optimisation**
   costs / benefit / risk / timing

   For example, the construction of a new sub transmission subassembly (high voltage lines and substation), where costs, benefits, risks and timing are optimised from this specific project point of view.

2. **Asset life cycle optimisation**
   cost / performance / risk / sustainability
   a) Individual assets (whole life cycles)
   b) Asset system integration level (performance sustainability)

   For example, the optimisation of all company owned power transformer life cycle activities while optimising performance in the long run with a certain asset strategy.

3. **Activity programme optimisation**
   cost / benefit / risk / timing of multiple activities across multiple assets

   For example, the optimisation of all life cycle activities for power transformer assets. /40/

2.4 Comprehensive Conceptual Approach

The asset management concept combines and synchronises management, engineering and information perspectives. So it harnesses a cross-disciplinary research from organisational design to the detailed analysis of technical systems. The asset management term is multidimensional and can be understood from very different angles: from a complex technical system analysis to short economical stock trading aspects. The following presentations condense the asset management concept from the energy systems perspective.

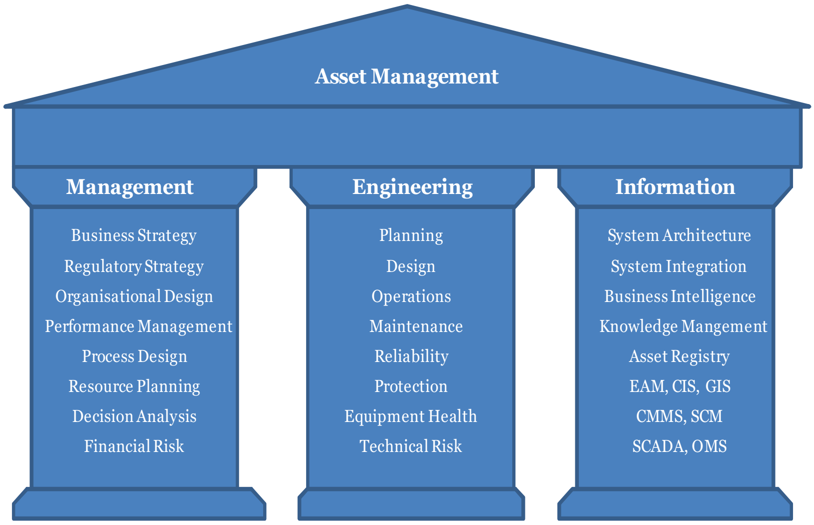


Figure 2-6 Asset management according to Brown and Humbrey is based on three pillars of competence: Management, Engineering and Information. Acronyms in the information pillar stand for ICT systems such as (EAM) Enterprise Asset Management, (GIS) Graphical Information System, and (CMMS) Computerised Maintenance Management System. /15/

Information lays the foundation for actions in network asset management. Manifold information is gathered from many sources: from field measurements, technical parameters, factory tests, scientific societies and economic forecasts. Sometimes information is even based on the intuition of equipment specialist. This requires data management and especially a general understanding about the concept. Thousands of network measurement points are being followed continuously in real-time and a vast amount of the information is recorded for later use. Several service providers are working among the network assets and gather information on site with technical measurement equipment and also essentially, with their senses. Scientific institutes, system operators and manufacturers are experimenting on component performance in a broad range of setups, with numerous scientific publications as an outcome. Colleagues in the transmission and distribution sector are changing experiences and information among themselves. Financial information is always involved when we are dealing with the assets. Component costs and the commodities market, labour cost indexes, network operational costs - the amount of data and information is manifold and vast and needs further validation and filtering case specifically.

Brown and Humbrey present organisational design and management as an essential pillar for a functioning asset management /15/. The general idea behind organisational design from the AM perspective is to reach a holistic view in the processes and in the business units. For example, network investment planning has to be in line with asset condition management and maintenance for a functional asset management.

There are a variety of business drivers in the electricity distribution business. For example John Rimell presents some of the central stakeholders in network asset management from the Eastern Electricity point of view which serves the eastern region of England. There are obvious beneficiaries such as customers, personnel, financial stakeholders and the regulator, but there are also influential parties and statutory organisations that have significant influence on operation policies and investment decision-making. /17/

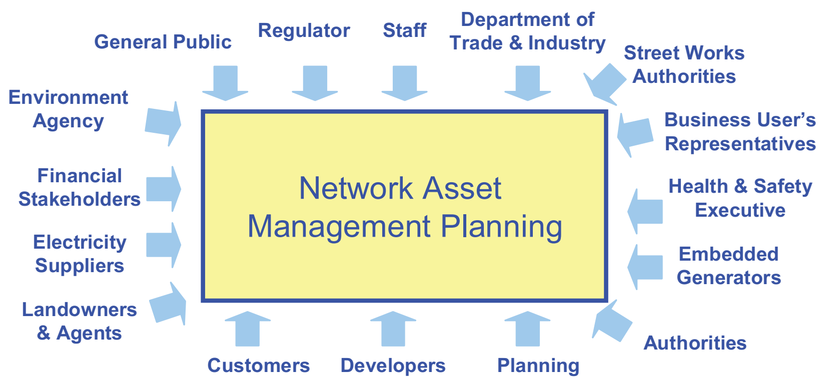


Figure 2-7 Some of the influential stakeholders around the electricity distribution business according to John Rimell. /17/

Each stakeholder brings their own drivers to the business in the form of quantitative or qualitative performance measures. For example, the finance and continuity of the supply targets can be presented with numbers, but there are many embedded qualitative drivers, such as environmental limitations and license conditions fixed by law. Rimell categorised drivers under six main headings which are then linked to network activities: /17/

- Financial
- Customer
- Distribution System Operator Licence
- Regulatory
- Statutory
- Environment, Health & Safety

Previous references underline and present a variety of attributes to be considered in power system asset management. Balzer et al. continues from this general view to an analytical practice and the asset management process is divided into four levels according to a top-down process:

Evaluation of the overall strategy for the complete fleet of equipment

Result: evaluation of the yearly budget, life cycle cost of the fleet

Utilisation of the reliability centered maintenance method

Result: consideration of which equipment has to be maintained / replaced, depending on the condition and importance for the system taking into account the yearly budget

Selection of suitable maintenance activities

Result: optimal maintenance strategy for the considered equipment, e.g. risk assessment, equipment life cycle costs

Optimal service for the components

Result: detailed service activity which has to be applied. /21/

Asset management in power systems is related to a multitude of factors and so every attempt to present the whole process and relations in one figure demands simplification. Balzer (et al.) describes the functional chains between finance, personnel, technology, customers and company factors. /21/

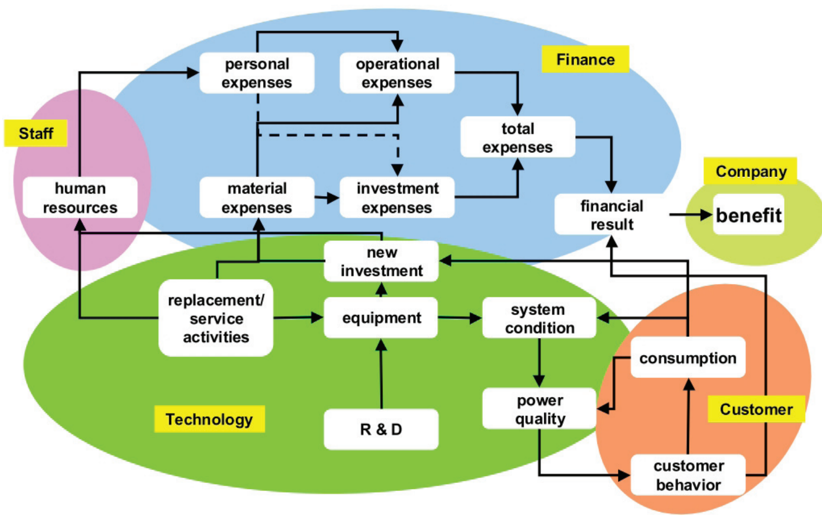


Figure 2-8 Functional chains of the asset management process considering finance, staff, technology, customer and company owner according to Balzer et al. /21/

Every white box illustrates an entity of analytical analyses build on quantitative or qualitative information based on the nature of task. These matters described in each white box in Figure 2-8 are relevantly simple, and transmission and distribution companies have performed these analyses for a long time with an increased benefit-cost focus and with increased applications of ICT. The analyses were and still are made with a narrow point of view. The main enhancement from asset management is the idea for a joint comprehensive analysis. /21/

Asset management involves a lot of information and so one essential demand is a structured data handling. Martin and Bamford /25/ classify four different approaches on the basis of complexity and discrimination: complexity characterises the number of attributes and factors taken into account in a maintenance strategy study, discrimination describes the ability to rank criticality from the highest to the lowest, for example.

There are several tailored computer programs for asset management such as RiBAM (risk-based asset management), Infor EAM (Enterprise Asset Management) and TAMIS (Transmission Asset Management Information System). Also, network information systems can include asset management modules, such as Tekla XPowers' RNA/AM (Reliability based Network Analysis and Asset Management) and Siemens PSS (Power System Simulation) Sincals' probabilistic reliability calculation module SINCAL-ZU. Usually programs are not immediately applicable without adjusting or at least understanding the assumptions and presets in the simulations.

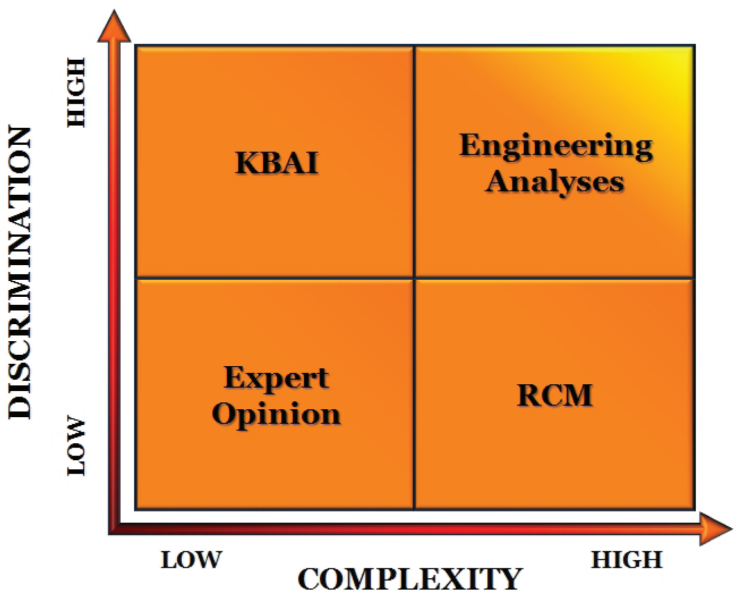


Figure 2-9 Complexity and discrimination for various maintenance models according to Martin and Bamford: KBAI means Knowledge Based Asset Integrity, RCM Reliability Centered Maintenance. /25/

An expert opinion is the most common strategy in the relatively simple maintenance planning, where asset risks and costs of the maintenance actions are low. Lightly documented analytical assessment methods are appropriate when the discrimination requirement rises and there is clear information available. One typical example is discrimination on the basis of the operational age for a low importance component. A knowledge Based Management approach evaluates the risks and the consequences for finding the critical assets and for directing the maintenance effort. The division between reliability centered maintenance and complex engineering analyses is hazier, however both methods deal with incomplete information and usually involve higher risks, wider consequences and costs of maintenance or renewal operations.

2.5 Condition Asset Management

The next reference shows an example assessment of 110 kV circuit-breakers for replacement and service activities described in the functional chains shown in Figure 2-8. The basic idea in ranking actions is to assess components based on their condition and importance from the system point of view. Component condition information is the foundation for quantitative asset management and it usually results from various analyses. Many times a qualitative assessment by maintenance personnel resulting from intuition from all the information available in the case is also included. Information collection is expensive so an asset manager must decide where would be the limit of effort put into condition assessment. A detailed laboratory inspection of the component condition is not possible because usually the process must run while assessing the system. /21/

In the case of 110 kV circuit-breaker condition assessment measurement methods for ranking could be, for example: /22/ /23/

- Age, manufacturer, environmental location
- Partial discharge measurement
- Gas analysis and density
- Insulating oil condition
- Visual inspection
- Infrared photography
- Switching time monitor
- Impedance measurements
- Frequency response analysis

The importance is determined by assessing the effects of the component failures on system reliability. In this method (Balzer et al.), measures from 0 to 100 are given for the whole component fleet for describing its importance and condition. The distance from the 45 degrees zero-point line is the base for the ranking. /18/

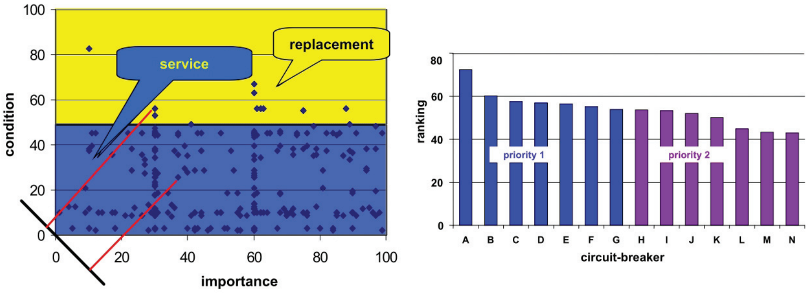


Figure 2-9 Assessment of 110 kV circuit-breakers, on the right is a priority diagram of circuit-breakers for replacement, according to Balzer et al. /18/

The priority determines the order for the actions but it does not define suitable maintenance strategy. The financial attribute needs to be taken into account to choose appropriate actions:

- **extension of the time in operation** by changing service interval,
- **replacement** of all components,
- **refurbishment and retro-fit actions** where certain parts are replaced,
- **upgrade or system enhancement**
- **redesign and re-configuration of the system.** /18/

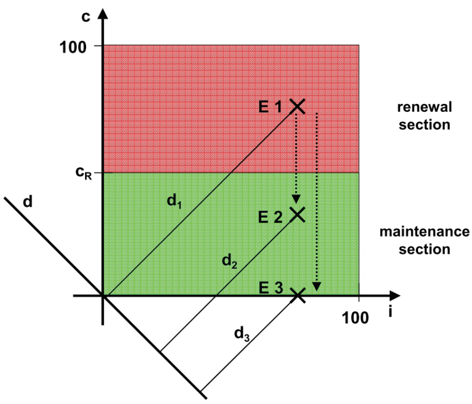


Figure 2-10 Evaluation of the system performance index (SPI) according to Balzer et al. /18/

Condition E1 is a start value and the transfer to E2 illustrates a transition followed by a refurbishment. E3 presents the result of the replacement. The maintenance strategy which gives the longest transition in the condition dimension per financial expense results the highest system performance index. /18/

There are several publications covering network asset maintenance prioritisation and reasonable service strategy. The basic elements in all these are determining the condition of the assets, creating priority for the actions, assessing overall benefit/cost of different actions and following the best practice. /18/ /24/ /27/ /32/ /33/ /54/ /58/

The electrical transformer is one of the most historically analysed components in power systems engineering: In the year 2010 20th of March, the IEEE database of power, energy and industrial applications included 612 817 publications and 14 345 deal with transformers. For comparison, that is six times more compared to overhead lines and 26 times more than asset management publications. /57/

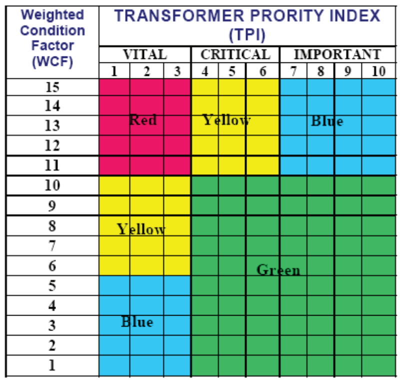


Figure 2-11 Transformer condition ranking matrix according to Weidmann-ACTI Inc., David Woodcock. /58/

One important task for an asset manager is to contemplate all asset related actions and undertakings: George Anders and John Endrenyi compare overall economics for different approaches, also with the option of ceasing all maintenance actions. /11/ /24/

One of the aims in asset management is to make the most of the system considering financial and quality performance. There are several approaches to the balance required between maintenance and renewal investment: Anders and Endrenyi present life curves for comparing maintenance policy effects on the operational life time of equipment.

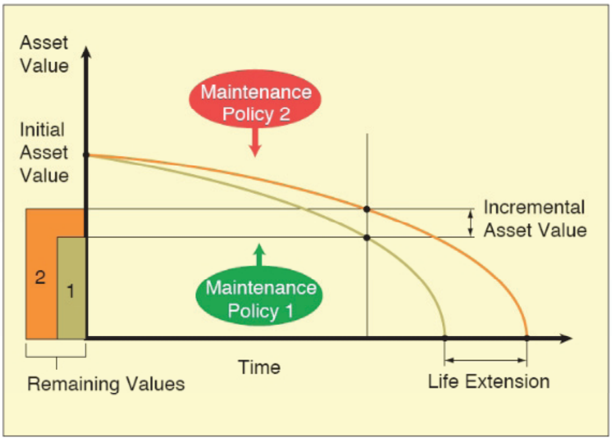


Figure 2-12 **Two life curves according to Anders and Endrenyi for the same equipment under two different maintenance policies where operating conditions are assumed to be the same. /11/**

An economic evaluation of different maintenance policies involve all the case related maintenance activities and expected number of failures. A general way to describe the future costs of different maintenance actions is to use present values. Typically, the price levels of these actions are assumed to stay the same.

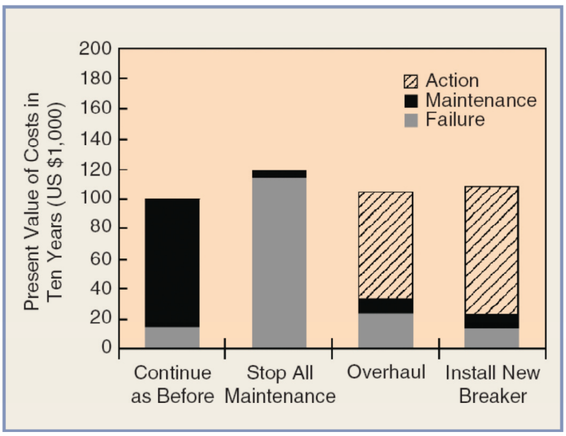


Figure 2-13 **A Cost diagram for the various maintenance policies with a ten year time horizon and with a three year time delay for the beginning of the new policy. /24/ /11/**

In this evaluation example the most expensive option is to stop all the maintenance actions, the most cost-effective options to continue as before. For achieving the highest quality, a new breaker should be installed, meaning higher costs compared to the current practice. However installing new equipment would be cheaper than to cease all maintenance actions. /24/

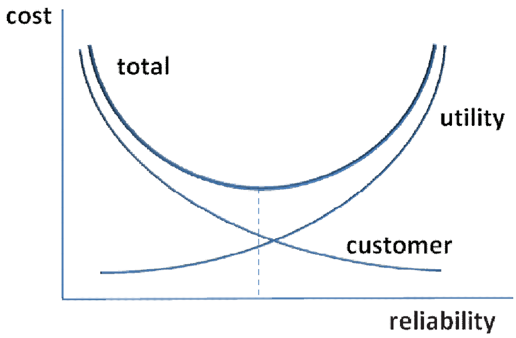


Figure 2-14 Total reliability costs presented by Allan and Billington. /16/

After the comprehensive asset management research, the relation between costs and reliability from the customer and utility perspective can now be discussed.

2.5.1 Life Cycle Research

A life cycle assessment goes deep into the physical fundamentals of the system when evaluating the current asset condition and the effects of various maintenance and operational policies. An asset manager must link material physics and a thorough understanding of the system functions and economics to gain an overall picture for decision-making. All asset managers need to find and combine relevant information, so the same need is faced in this research.

A power transformer is one of the most important components of the power system and it is a relevantly old invention of the electrical age. The invention of the power transformer in a constant AC power supply system dates back to the end of the nineteenth century /32/. Thus, a lot of information for transformer life cycle management is available today. Despite this, robust time-based and deterministic decision-making is the common practice, although there is lot of information available for case sensitive decision-making. Information by itself does not make the difference in asset management, but the whole process in decision-making needs to take these pieces of information into use. A new way of decision-making requires a lot of effort and when things are running quite well in the transmission and distribution sector; the adoption of new methods is not so tempting.

A general approach for transformer aging is to model the degradation of the insulation paper. A classical aging theory is based on the Arrhenius equation, which was developed in the 17th century. This equation models the dependency between absolute temperature and the chemical reaction speed. Montsinger conducted practical experiments in the special case of degradation of the insulation paper in oil in the 1930s and further developed the Arrhenius equation. Since then Montsinger's equation has been the most common way to model the aging of insulation. /27/

Asset management aging models in some cases combine analytical equations and probabilistic methods at the same time. For example, a modern application of the Arrhenius equation with a probabilistic sensitivity analysis presents the degradation of transformer paper insulation and reliability of the component based on an aging model. Arjan Schijndel presents an example calculation of the degree of polymerisation (DP-value) on the basis of time in an IEC standard with 98 °C normal aging reference temperature with a 5 °C range of change. /33/ /52/

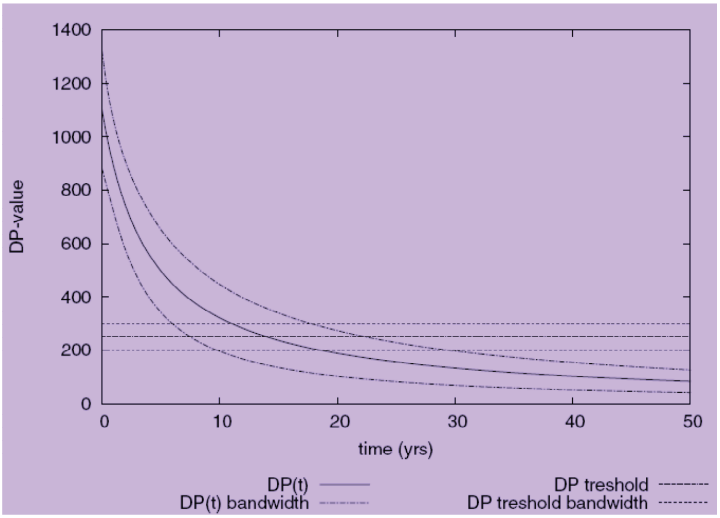


Figure 2-16 An example of the time evolution of the degree of polymerisation (DP) value and the DP-threshold with accuracy bandwidths according to Arjan Schijndel /33/. The degree of polymerisation value describes the condition of the power transformer insulation paper.

The degree of polymerisation value of the transformer insulation paper describes the tensile strength of the material. The tensile strength of the insulation paper is under pressure, especially when something abnormal occurs during transformer operation. Transient fault currents create physical forces and movement in transformer windings. A major question then is will the paper insulation tolerate movement without tearing apart?

The following Arjan Schijndel model presents the reliability evaluation of transformer paper insulation according to operation years. The calculation is made at a constant 98 °C reference temperature, which is a relatively high value compared to average Finnish network transformers where average loading is around half of the nominal. Figure 2-16 shows that after around 10- 20 years in operation the paper DP-value approaches 200-150 level, which is considered to be the end of life of paper insulation: the brittle paper tensile strength is then so low that it would crumble if there would be any transient current based movement. When the DP-value is around 200-300, the tensile strength drops to the 40-60 % level compared to new paper. The localised transformer breakdown voltage drops remarkably when the insulation paper cracks and then partial discharge can start to self-destruct the transformer at an increasing pace. /33/ /54/ /27/

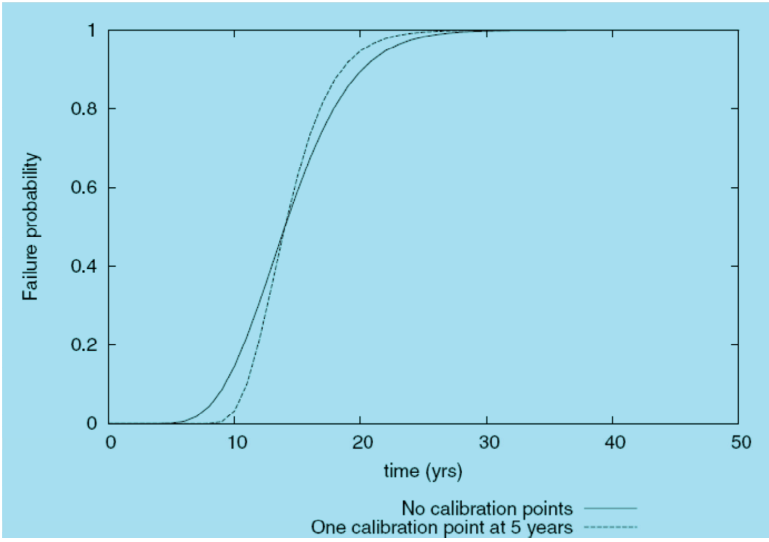


Figure 2-17 Paper insulation failure probability versus time without measured input and with the incorporation of a degree of polymerisation value measurement after five years in operation. /33/

Paper insulation failure probability does not exhaustively present the whole network power transformer failure probability but it shows the probability of surviving or breaking in the situation where paper tensile strength is on the line. The failure probability distribution is relevantly wide in Figure 2-17, especially when there are no DP-value calibration points to verify what the insulation condition is. In this example, diagnostic information after five years in operation narrows the distribution by approximately five years from both ends. /33/

There are other factors besides temperature which affect paper insulation ageing. Lundgaard et. al models the effect of water and oxygen content, and oil acidity in the Kraft paper degree of polymerisation /53/. Analytical ageing models are still being developed to take more details into account. An asset manager usually has to operate with different pieces of information, where only some factors are analytically modelled.

The next model shows an empirical approach for evaluating the ageing of paper insulation in transformers. The consequences of different timely maintenance on ageing are also reflected on. Generally, electrical networks in Finland are built with n-1 redundancy when substation level power transformers are considered. Because of that, a power transformer under normal operation conditions is near the half of the rated loading capacity and the operating temperature is much lower than the theoretical temperature aging models. The following figure shows the DP-development for a typical network power transformer from a statistical point of view.

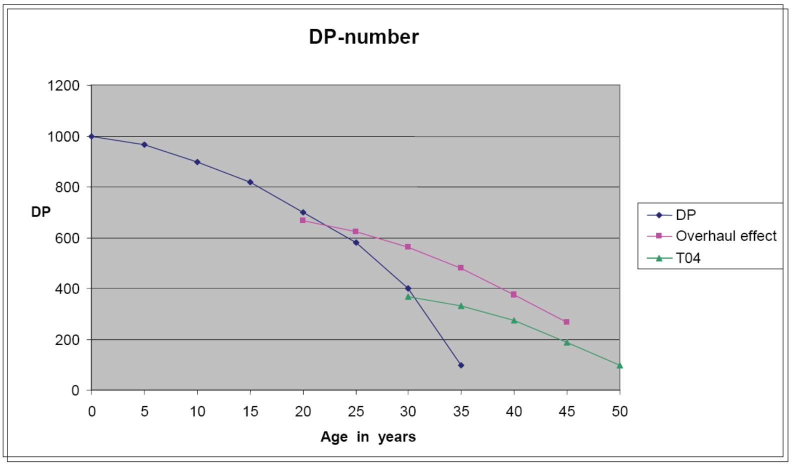


Figure 2-18 A specific use case model for the development of the DP-number of a paper insulation in a power transformer with lower loading history. During the transformer overhaul the paper insulation and oil are dried, which slows down the degradation process. Right timing for overhaul is essential: in this figure the correct timing is around 20 to 25 years. /26/

The significance of water, oxygen and acidity content in oil increases over time when the transformer operation temperature is relatively low. The degradation process of paper insulation creates water and the water in paper auto-accelerates the degradation by itself. This auto acceleration theory is visible in the curve in Figure 2-18: towards the end of the paper insulation life-time the degree of polymerisation accelerates due to the auto-acceleration phenomena. Lehtonen presents the idea that it is reasonable to schedule major transformer overhaul before the auto-acceleration process speed up significantly due to the paper degradation increased moisture content. /53/ /26/

In practice things are usually even more complicated than one glimpse at the ageing models might indicate. The paper insulation aging effects of temperature, oxygen content and acidity in oil are proven facts, but still these theories need to have diagnostic information for more pertinent judgement. Structural solutions also have a large effect on the life cycle of transformer and a diagnostic approach gives valuable information on how aging is proceeding in a particular case.

One of the most common cooling solutions for oil-immersed power transformers is the Oil Natural Air Natural (ONAN) system, where oil is moving inside the transformer tank on the basis of oil thermal expansion. An aging model in this particular case can evaluate the natural oil flow from the top and bottom oil temperature difference. In normal cases, the temperature naturally rises with height in such a way that the highest temperature is near the top of the winding. Unambiguous hot-spot location requires several fibre-optic measurements, but with natural oil flow, the hot-spot is generally located slightly inside from the top of the winding, although the hot-spot location can differ largely due to the winding structure and if the oil flow is forced. The hottest spot in the winding suffers the highest paper insulation ageing stress as well. The following figure shows the DP-values along the height of the winding of an Oil Forced Air Forced OFAF cooled power transformer. /52/ /55/ /56/

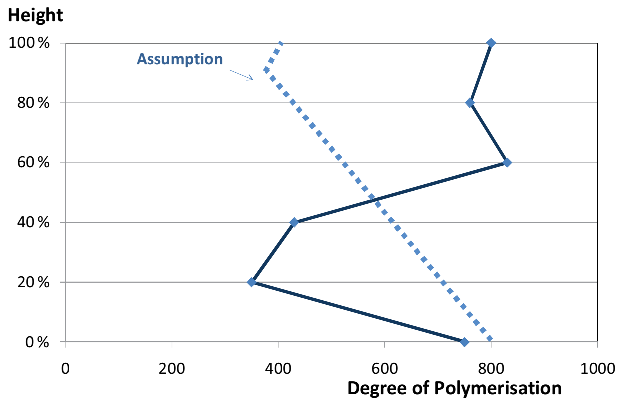


Figure 2-19 Example of a power transformer unit's* low voltage winding DP-values along the height after 20 years in operation: Height 100 % is the top of the winding and 0 % is at the bottom. *) Unit information: Generator transformer of nuclear power plant, 415/20 kV, 800 MVA, OFAF-cooled, manufactured in 1977, DP-value measured in 1998, average loading 90 % of nominal power, average top-oil temperature 50 °C. /27/ DP-value measurement results and /54/ assumption model are combined in the figure.

The hottest spot seemed to be located quite low on the winding, around one fifth of the length from the bottom to the top. Forced oil flow can alter the hot-spot location remarkably as does the winding structure. Figure 2-19 also shows the assumption, which is based on natural oil flow where hottest spot is located little bit inside from the top of the winding. According to the natural convection thermal model assumption, the temperature as well as the degradation effect decreases from the top winding hot-spot to the bottom of the winding. /27/ /52/ /54/

Asset manager needs to understand the fact that we are dealing with incomplete information and theories. International research is searching for solutions for theoretical aging models, for example, on transformer insulation degradation, which is useful, but not as one thorough representation of the asset manager's dilemma. A statistical asset analysis and especially diagnostics solutions provides useful information in addition to theoretical models.

The following example shows the relevancy of the combination of a statistical approach and theoretical model. The effect of the temperature has been historically overrated because relatively few network transformers fail solely due to the temperature degradation. Network power transformers are used with lower load compared to the severe duty cycles industrial transformers are subject to. An international statistical failure survey points out that there are several types of transformer failures and the following figure shows the distribution of failure locations. Data from more than 7000 transformer units were gathered during 1968-1978 from 13 countries including Finland. /27/ /50/ /51/

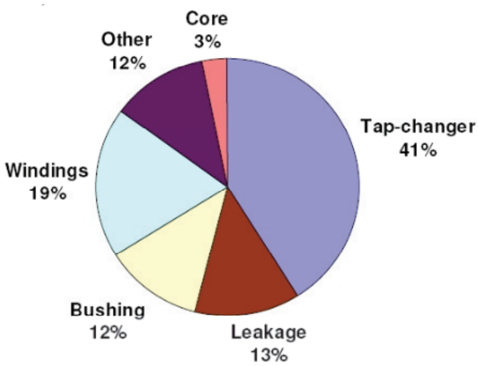


Figure 2-20 Transformer failure statistics of different components reported by Cigre and presented by Jongen et. al. The failure statistics consist of approximately 800 fault cases. /50/ /51/

- Tap-changer: Includes the off-load as well the on load tap changers
- Leakage: Problems concerning the tank and the dielectric fluid.
- Bushing faults
- Windings: Short circuit of the windings of a transformer
- Core: Problems concerning the magnetic circuit.
- Other: for example temperature problems /50/

Almost half of the transformer component failures in the CIGRE survey were attributed to defects in design, materials and manufacturing. /51/

So far, this chapter has condensed many international research results from transformer life cycle management with several practical, statistics and theoretic attributes. One reason for this deep-narrow transformer condition perspective is to point out the fact that, besides theoretical modelling, asset manager needs practical diagnostic solutions to calibrate the overall condition attributes of the unit. The need for diagnostic calibration rises from the fact that the asset condition theories are not unambiguously comprehensive in reflecting the real world without current condition information. Another essential reason for the condition monitoring is that the real component manufacturing deviates from the theoretical presumptions of homogenous structure, which was visible in the Figure 2-19 case example.

2.5.2 Condition monitoring

The online condition equipment manufacturer GE Energy markets the transformer online gas monitoring product Hydran also as a potential reduction for insurance costs. The Cigre guide on the economics of transformer management presents a simple calculation method for the evaluation of the total benefits for an online monitoring equipment investment. The next figure shows an example evaluation for a transformer fault type and probability for the transformer with and without online monitoring. /59/ /61/

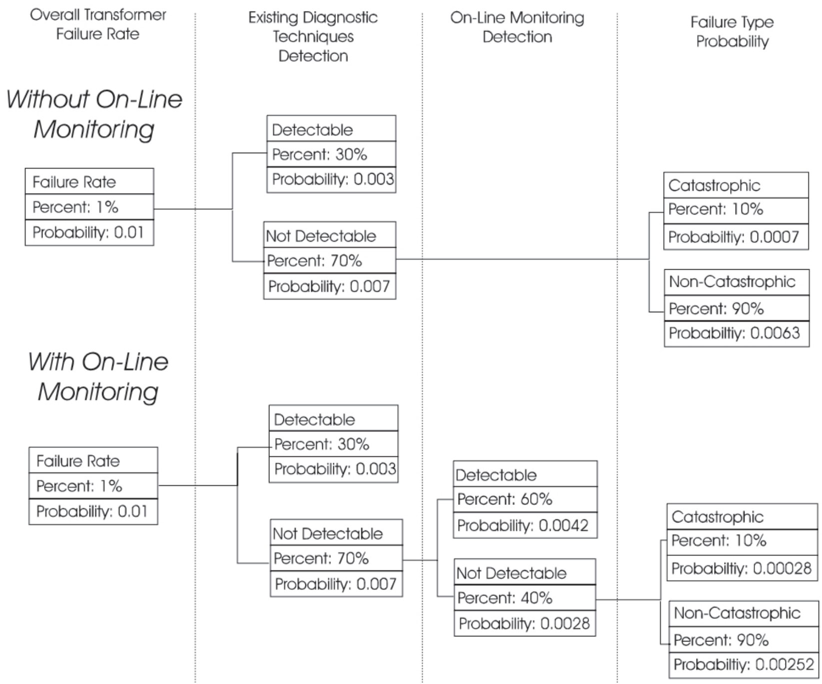


Figure 2-21 Power transformer failure probability trees with on-line monitoring and without it applying existing traditional frequent off-line diagnostic detection. /59/

The Cigre guide presents two probability trees in the example calculation with difference that online monitoring reveals indicatively 60 percent of the incipient faults compared to the situation where only frequent diagnostics are applied. This particular calculation method means that catastrophic failure probability decreases from 0,0007 to 0,00028 per year and non-catastrophic failures also decrease in the same proportion. A key measure in this example is the assumption of the fault detection rate for online monitoring equipment. A sensitivity analysis is beneficial to evaluate the reliability modelling and the applied rates should be updated with topical information. /59/

Generally, online monitoring equipment prices have decreased and are still decreasing due to the development of ICT development and the increasing application of such technology /59/. The earlier Cigre calculation is applied in the fifth chapter to evaluate the benefits in the Helsinki power transformer scenario with the findings of local attributes for reliability. Increased asset condition knowledge enables investment delay to some degree without decreasing reliability compared to the situation without on-line condition monitoring. /72/

2.6 Summary and Discussion

The central purpose of electricity distribution asset management is in balancing comprehensive costs throughout the asset life-cycle and to seek return on investment. Asset management decision-making is dependent on a significant number of factors and in many cases there is no unambiguous model for these factors. It requires lot of case related incomplete data which still is dependent on expert judgment in applying the information elsewhere. One example of this is power transformer paper insulation's degree of polymerisation as a function of operational time. Nevertheless, there are enough data to model the development with a sensitivity analysis to understand its relevance in the overall asset management costs. Reliability statistics are important and when electrical network components are already very reliable, there is a need to gather information internationally in order to get sufficient data for the analysis. This thesis applies power transformer failure statistics in assessing quality expenses. Three different statistical sources are applied: Cigre international surveys, Fortum service's local Finnish surveys and RTE's fleet analysis statistics. /35/ /51/ /59/ /65/ /87/

The PAS 55 standards along with Balzer's research for asset management concepts form an important base for this work, where global economic scenarios and local information are applied /40/ /21/. The increasing trend for online monitoring requires an analysis of its significance, and Cigre guide gives the initial background for this undertaking /59/.

3 Economic Modelling I: Dynamic Cost Function

A comprehensive cost function is the mathematical fundamental for quantitative scenario modelling. This chapter presents the equations which are used to model asset management cost behaviour. Naming the main cost functions for electricity network investments is simple, but detailed case applicable functions are long: that is why the equations are presented step by step.

3.1 Comprehensive Asset Cost Function

A logical cost partition for overall expenses is the division into capital, operational and maintenance expenses /9/. In addition, factors related to quality - mainly concerning system reliability and environment must be taken into account to make a comprehensive cost function. Also, the present day regulation model in Finland has a marked effect on a distribution network company's investment programs through allowed profit and operational efficiency improvement obligations. The capital and the operational expenses are direct expenses to the distribution system operator, whereas the maintenance expenses comprise from the direct expenses of preventive maintenance and expected expenses of the corrective maintenance. In this thesis, the quality expenses reflect the fundamental societal valuation for the continuity of the electricity supply service, hence giving the actual reference point for the asset manager beside the qualitative targets of existing service standards and the common engineering aim of functioning systems.

Cost function:

$$C_{total} = C_{capex} + C_{opex} + C_{maintex} + C_{qualex} \tag{3.1}$$

Where,

C_{total}	Comprehensive expenses	$C_{maintex}$	Maintenance expenses
C_{capex}	Capital expenses	C_{qualex}	Quality expenses
C_{opex}	Operational expenses		

Each constituent part of the cost function includes relations to several factors, such as electricity consumption, material prices, state of the economy, city development and zoning, component reliability and maintenance intensity. The whole dynamic cost function is quite long and the final detailed case applicable function varies between each case because of the different relationships and needed emphasis. The general relations are first presented.

3.2 Physical Asset Life Cycle

The figure below represents a basic view of the behaviour of physical assets: there is a certain life time for the materials which determines the expected duration of the operational life. To reach the required life time reliably, a maintenance program is usually needed. This includes several smaller frequent and condition based maintenance actions and perhaps a major overhaul once the component's life cycle. The maintenance program varies depending on the nature of the component and its loading characteristics and criticality. From the asset manager's point of view, the focus is on operational time up until the renewal process; the manufacturer optimises the component construction based on international standards and customer specifications.

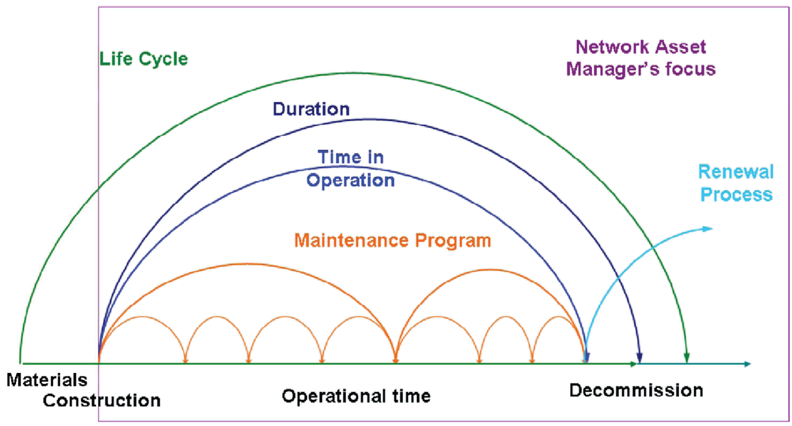


Figure 3-1 The lifetime concept for ageing infrastructure. This work is focused on the part of the life span from the manufactured element to the renewal process. /83/

The entire electrical network infrastructure is a complex combination of these elements, and is planned to operate at all times. Thus, investments and maintenance strategy have to be comprehensively planned and optimized for the desired service target. A sub-transmission and distribution network is constructed from tens of thousands of components which have a varying life cycle. Merely in the substations there are interconnected systems such as building, high voltage switchgear, power transformer and auxiliary systems which have a life cycle length from some years to even a hundred years. An asset manager has to have a comprehensive view of this matter in order to schedule actions logically. A deep understanding of the components and interconnected systems is required when integrating the overall asset management program.

3.3 Capital Expenses

Capital expenses for an electrical component are related to material and manufacturing costs. Each component type has a different material fingerprint, which needs to be taken into account with the involvement factor $f_{mat(x,m)}$. Almost always there is some kind of construction site where these components are finally installed. In fact, construction costs play a major role in the overall network expenses and the building cost index curve portrays that part.

$$C_{capex} = \sum_{x=1}^{n} p_{ss(x)}(t_0) \left[\sum_{y=1}^{m} \frac{i_{\mathrm{mat\,(m)}}(t)}{i_{mat\,(m)}(t_0)} f_{mat\,(x,m)} + \frac{i_{cons}(t)}{i_{cons}(t_0)} f_{cons\,(x)} + \frac{i_{lab}(t)}{i_{lab}(t_0)} f_{lab\,(x)} \right] \tag{3.2}$$

where,

$f_{mat(x,m)}$	Cost involvement factor for manufacturing material m for subsystem x
$f_{cons\,(x)}$	Construction cost relation to whole subsystem x investment
$f_{lab\,(x)}$	Labour cost relation to whole subsystem x investment
$i_{mat\,(m)}(t)$	Nominal material m price index value in the future moment
$i_{mat(m)}(t_0)$	Manufacturing material m price index present-day value
$i_{cons}(t)$	Nominal construction price index value in the future moment (t)
$i_{cons}(t_0)$	Construction price index present-day value
$i_{lab}(t)$	Nominal labour cost index value in the future moment t
$i_{lab}(t_0)$	Labour cost index present-day value
$p_{ss(x)}(t_0)$	Present day price for a certain subsystem x investment

For example, when negotiating about future purchases, global power transformer suppliers want to bind a sale contract with a price clause on metal, oil and labour cost indexes. A network Company can try to negotiate a fixed price even for the future, but in that case a manufacturer has to evaluate the material price risk and name the price for it.

Figure 3-2 Copper Price development in London Metal Exchange /34/

The material price effect for a company operating in the energy sector is so significant that it is reasonable to inquire and observe the commodities markets frequently. For example, power transformer prices have approximately doubled during the years 2003 to 2008 due to the increase in manufacturing material prices and the global investment pressure in the markets.

Capital Expenses for power transformers

The next list presents an applicable solution for the transformer price clause relations and material and index involvement factors[I] which are applied later on:

Carbon steel	**25 %**
Copper	**20 %**
Transformer Oil	**10 %**
Labour costs index	**40 %**
Producer Price index	**5 %**

Transformer price factors are based on the manufacturers' terms of sale, but instead of labour costs and a producer index, manufacturers' commonly use fixed rates. A calculation model is used with the power transformer prices used by Helen Electricity Network and thus it describes transformer future prices more case sensitively. The installation environment also differs between city centre underground and suburban substations, and so site installation specifics have to be taken into account.

[I] Price clause relation indices for power transformer capital expenses are derived from the Helen Network Ltd's data reflecting closely the actual unit purchases.

The annual capital costs for power transformer unit:

$$C_{capex\_PT}(t) = C_{PT} f_{PT}(t) + C_{MOH} f_{MOH}(t) + C_{OLD} f_{OLD}(t) + C_{special} f_{special}(t) \tag{3.3}$$

The cost involvement factor for power transformer price:

$$f_{PT}(t) = \frac{i_{Cu}(t)}{i_{Cu}(t_0)} f_{Cu} + \frac{i_{St}(t)}{i_{St}(t_0)} f_{St} + \frac{i_{Oil}(t)}{i_{Oil}(t_0)} f_{Oil} + \frac{i_{lab}(t)}{i_{lab}(t_0)} f_{PT\_lab} + \frac{i_{\mathrm{pro}}(t)}{i_{\mathrm{pro}}(t_0)} f_{PT\_\mathrm{pro}} \tag{3.4}$$

$$p_{MOH}(t) = \frac{i_{lab}(t)}{i_{lab}(t_0)} f_{MOH\_lab} + \frac{i_{pro}(t)}{i_{pro}(t_0)} f_{MOH\_cons} \tag{3.5}$$

$$f_{OLD}(t) = \frac{i_{OLD\_tech}(t)}{i_{OLD\_tech}(t_0)} f_{OLD\_tech} + \frac{i_{lab}(t)}{i_{lab}(t_0)} f_{OLD\_lab} \tag{3.6}$$

$$f_{special}(t) = \frac{i_{cons}(t)}{i_{cons}(t_0)} f_{special\_cons} \tag{3.7}$$

Where,

$C_{capex\_PT_x}(t)$	**Power Transformer unit's capital expenses in the year** t **(€)**
C_{PT}	**PT investment price in the beginning of assessment (€)**
C_{MOH}	**PT major Overhaul expenses in first year (€)**
C_{OLD}	**PT on-line diagnostic (OLD) equipment investments in first year** t_0 **(€)**
$C_{special}$	**PT special installation expenses in first year** t_0 **(€)**
$i_x(t)$	**Price relation indices development along the time for different cost elements, such as construction or labour costs**
f_{Cu}	**Subsystem price relation factor for copper price**
f_{St}	**Subsystem price relation factor for steel price**
f_{Oil}	**PT unit price relation factors for oil**
f_{x_lab}	**PT, MOH or OLD price factor for labour costs**
f_{x_pro}	**PT, MOH or OLD price factor for producer price index**
f_{x_cons}	**MOH and special installations price relation factor for construction cost index**
$p_{MOH}(t)$	**Major overhaul price relation factor in the year** t
$f_{OLD}(t)$	**OLD investment price relation factor in the year** t
$f_{special}(t)$	**Price relation factor for special installations in the year** t **, e.g. underground substation**

Power transformer capital expenses comprise of investments, installation, major overhauls and diagnostic equipment expenses, which are dependent on the price development of the different materials and labour, and also on construction and producer index development.

3.4 Operational expenses

Investments have an effect on **operational expenses** and so the decision-maker has to be aware about the balance between capital and operational expenses. Here operational expenses for a certain investment are considered to be a function of network losses and changes in personnel costs and Transmission System Operator grid fees. Operational cost evaluation is based on forecasts: first, electrical network structure, operation and loading determine transmission and distribution losses and second, energy price forecasts determine the overall costs for the network losses.

The main parameters behind operational expenses:

$$C_{opex}\left(p_{energy}(t), \Delta z_{network}, s_{network}(t), \Delta c_{personnel}, \Delta c_{gridfee}, c_{LossCapacity}\right) \tag{3.8}$$

where,

$p_{energy}(t)$	**Energy price as function of time**
$\Delta z_{network}$	**Network impedance changes due to an investment**
$s_{network}(t)$	**Network loading as function of time**
$\Delta c_{personnel}$	**Changes in the personnel costs due to an investment**
$\Delta c_{gridfee}$	**Changes in the National TSO grid fees due to an investment**
$c_{LossCapacity}$	**Network marginal costs for the required loss transfer capacity**

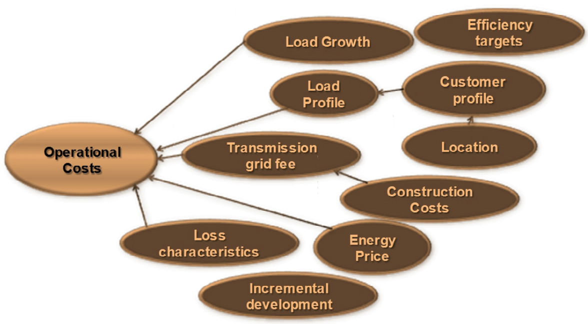


Figure 3-3 Cost factors that have an effect on operational cost development when there are no changes in operational staff.

A specific equation for operational costs in the earlier mentioned power transformer investment example can be calculated for different scenarios related to consumption and energy price development, and also to network construction and labour cost scenarios. The transformer loading scenarios are made for 17 years ahead until the year 2030 and they are based on different city development plans and economic prospects.

Equation for yearly operational costs for the power transformer (PT):

$$C_{opexPT}(y) = \left(p_{LoadLossE}(y) \frac{i_{energy}(y)}{i_{energy}(y_0)} + C_{TSOfeePT}(y_0) \frac{i_{cons}(y)}{i_{cons}(y_0)} \right) E_{LoadLossPT}(y)$$
$$+ \left(p_{NoLoadLossE}(y) \frac{i_{energy}(y)}{i_{energy}(y_0)} + C_{TSOfeePT}(y_0) \frac{i_{cons}(y)}{i_{cons}(y_0)} \right) E_{NoLoadLossPT}(y)$$
$$+ \ C_{\mathrm{TransMC}} \left(\hat{P}_{TransformerLoss} \right) \frac{i_{cons}(y)}{i_{cons}(y_0)}$$

Where, (3.9)

$C_{opexPT}(y)$	**Yearly operational costs for the power transformer in the year** y
$p_{LoadLossE}(y)$	**Load loss energy price in the specific year** y
$p_{NoLoadLossE}(y)$	**No-load loss energy price in the specific year** y
C_{TSOfeePT}	**Balanced TSO grid fee for PT loss load profile**
$E_{LoadLossPT}(y)$	**Yearly load loss energy for the PT unit in the year** y
$E_{NoLoadLoss\,PT}(y)$	**No-load loss energy for the PT unit in the year** y
C_{TransMC}	**Yearly marginal cost for building the power loss transferring capacity**
$\hat{P}_{TransformerLoss}$	**Peak power for the losses of the power transformer when peak responsibility factor is 100 %**
$i_{energy}(y)$	**Energy price index in the year** y
$i_{cons}(y)$	**Construction price index in the year** y

Equation for yearly power transformer load and no load losses in the year (y):

$$E_{LoadLossPT}(y) = P_{Load\,N} \sum_{h=1}^{8760} \left(\frac{S(h) \dfrac{f_{eLoadPT}(y)}{f_{LoadPT}(y_0)}}{S_N} \right)^2 \quad (3.10)$$

$$E_{NoLoadLossPT}(y) = \sum_{h=1}^{8760} PT_{ON\_OFF}(y,h)\, P_{NoLoad\,N} \quad (3.11)$$

Where,

$P_{Load\,N}$	**Power Transformer nominal load losses**
$P_{NoLoad\,N}$	**Power transformer no-load losses at the nominal voltage**
$S(h)$	**Transformer loading for hour** h **of the year**
$f_{eLoadPT}(y)$	**Load growth factor for the year** y
$f_{LoadPT}(y_0)$	**Load growth factor for the first simulation year** y_0
S_N	**Rated power of the transformer**
$PT_{ON\_OFF}(y,h)$	**Boolean value whether power transformer is in operation or not during the hour** h **in the year** y

The Load Growth factor is calculated on the basis of peak load development scenarios created for every power transformer. Peak load development scenarios for winter and summer time are used in the load growth factor by weighting winter peak load with 2/3 share and summer time with 1/3 share.

$$
\begin{aligned}
f_{eLoadPT}(y) &= \frac{2P_{eWinterPT}(y) + P_{eSummerPT}(y)}{3} \\
f_{LoadPT}(y_0) &= \frac{2P_{WinterPT}(y_0) + P_{SummerPT}(y_0)}{3}
\end{aligned}
\qquad (3.12)
$$

$$
\left(\frac{f_{eLoadPT}(y)}{f_{LoadPT}(y_0)}\right)^2 = \left(\frac{2P_{eWinterPT}(y) + P_{eSummerPT}(y)}{2P_{WinterPT}(y_0) + P_{SummerPT}(y_0)}\right)^2 \qquad (3.13)
$$

Where,

$P_{eWinterPT}(y)$	**Power transformer winter peak load in the year** y
$P_{eSummerPT}(y)$	**Power transformer summer peak load in the year** y

The National Transmission System Operator's (TSO) grid fee for a local Distribution System Operator (DSO) is based on four factors: total electricity consumption, hourly power transfer, reactive power balance and amount of TSO to DSO connection points. The total electricity consumption factor has a different expense for wintertime and other consumption. The TSO grid fee changes due to the fact that the power transformer losses are roughly around 5 to 8 percent of the total units' operational expenses. A balanced grid fee for power transformer losses is calculated on the basis of electricity consumption division between **winter time** (January, February, March and November, December) and **other time** (April to October) in Helsinki.

Equation for balanced TSO grid fee for power transformer losses (€/MWh):

$$
C_{TSOfeePT}(x) = \frac{E_{LossWinterPT}(x)}{E_{LossYearPT}(x)} C_{TSOfeeWinter} + \frac{E_{LossOtherPT}(x)}{E_{LossYearPT}(x)} C_{TSOFeeOther} + C_{TSOtransfer} \qquad (3.14)
$$

Where,

$C_{TSOfeePT}(x)$	**Balanced TSO grid fee for power transformer** x **losses**
$E_{LossWinterPT}$	**Power Transformer energy losses in winter time**
$E_{LossOtherPT}$	**Power Transformer energy losses at other times**
$E_{LossYearPT}$	**Power Transformer energy losses in the year**
$C_{TSOfeeWinter}$	**TSO grid fee for winter time consumption**
$C_{TSOfeeOther}$	**TSO grid fee for other time consumption**
$C_{TSOtransfer}$	**TSO transfer cost for DSO**

Table 3-1 Fingrid TSO grid fee unit prices 2008-2013.[I]

€/MWh	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*
Consumption, wintertime	2,16	2,28	2,4	2,52	3,48	3,94
Consumption, other time	1,08	1,14	1,20	1,26	1,74	1,97
Use of grid, input into grid	0,30	0,30	0,30	0,30	0,50	0,70
Use of grid, output from grid	0,66	0,68	0,70	0,72	0,80	0,90

Naturally the winter time consumption TSO grid fee is higher as peak load demand is in winter times. In the year 2010 in the Helsinki DSO area, 46 % of the consumption occurred in the TSO defined winter time and 54 % outside this time. Nevertheless, during the winter time power consumption is higher and power transformers are loaded at higher levels. Note that load losses increase in relation to the square of the power as well. The following figure presents the Helen Electricity Networks power transformer fleet loss energy shares in the winter and at other times.

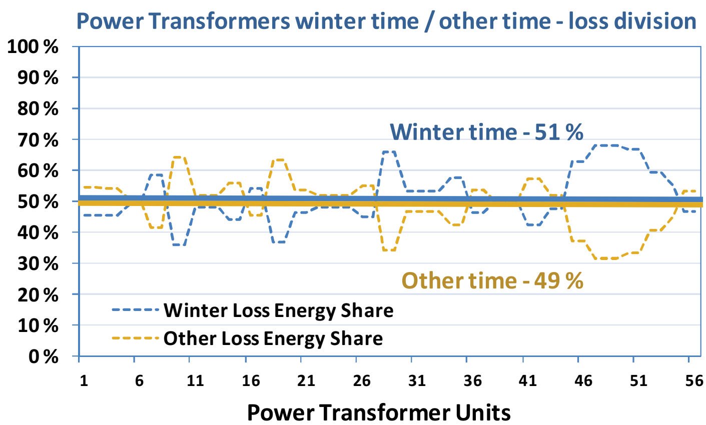


Figure 3-4 Power transformer loss energy shares in TSO's winter and other time.

So, 51 % of the yearly power transformer losses occur in the winter time and 49 % in other times on average. Some power transformer units are located in residential areas where there are electrical heated houses and so there the winter share is of course higher. TSO grid fees also depend on the generation of electricity in the DSO subtransmission network. In the year 2012 there are approximately 1100 MW of electricity generation capacity in Helsinki, which is so far connected to 110 kV subtransmission network owned by Helen Electricity Network LTD. This generated

I Transmission System Operator – Fingrid Oyj, ***Fees for TSO Grid Service***, http://www.fingrid.fi/en/customers/

electricity reduces the TSO grid fee transfer costs, but this has such a marginal effect in this evaluation and so the average between the input and output transfer costs is used. The balanced TSO grid fee increases the power transformer loss energy cost with 3,8 €/MWh in the year 2013 and future TSO grid fee development is related to construction cost index development scenarios, as stated in Equation 3.9.

Building the subtransmission network is costly and it also concerns the capacity that has to be built to transfer the power losses in the substations and in the distribution network. In this example the subtransmission transfer marginal cost is evaluated in terms of power transformer losses with the following equation.

Equation for annual transfer capacity marginal costs (€/kW/a):

$$C_{TransMC} = \frac{CRC_{Trans}}{P_{TransCapacity}} r \frac{(1+r)^{t_{lifetime}}}{(1+r)^{t_{lifetime}} - 1} \hat{P}_{TransformerLoss} \tag{3.15}$$

Where,

C_{TransMC}	**Marginal cost for the power loss transferring capacity**
r	**Rate of interest**
$t_{lifetime}$	**Economic lifetime of the subtransmission network**
CRC_{Trans}	**Current replacement cost of the 110 kV subtransmission network**
$P_{TransCapacity}$	**Transmission capacity of the 110 kV subtransmission network**
$\hat{P}_{TransformerLoss}$	**Peak power for the losses of the power transformer**

The energy price changes hourly and so there is a different energy price for load losses and no-load losses. The DSO Company buys electricity loss energy from the retail market and so the following marginal increases need to be added to the system price: naturally the load loss factor is relatively higher because majority of the load losses is consumed when the daily price is higher. The actual DSO's premium over the electricity system price in the case is 13 % for load losses and 3 % for no-load losses. The no-load loss premium over system price is quite low, because the shape of the consumption curve is the same regardless of the time of the day. These premiums are depending on the electricity retail market development.

$$p_{NoLoadLossEnergy}(y) = p_{system}(y) f_{NoLoadShape}(y), \quad f_{NoLoadShape}(2010) = 103\% \tag{3.16}$$

$$p_{LoadLossEnergy}(y) = p_{system}(y) f_{LoadLossShape}(y), \quad f_{LoadLossShape}(2010) = 113\% \tag{3.17}$$

Where,

$p_{NoLoadLossEnergy}(y)$	**Yearly average energy price for no-load losses in the year y**
$p_{system}(y)$	**Yearly energy system price in the year y**
$f_{NoLoadShape}(y)$	**Energy price factor over the system price in the year y for no-load losses**
$f_{LoadShape}(y)$	**Energy price factor over the system price in the year y due to the daily shape of the load loss curve**

Finally, placing equations (3.10), (3.11), (3.13), (3.14), (3.15), (3.16) and (3.17) into equation (3.9) will give the annual operational cost of one power transformer for a given future scenario.

3.5 Maintenance Expenses

Maintenance management for an electricity network applies a wide range of actions, measurements, analysis and monitoring to thousands of components. Maintenance programs are based on scattered incomplete information and so it is a complex task to make a systemic analysis that applies to the whole system. There is a limited amount of information concerning the relation between quantities of maintenance actions and system reliability.

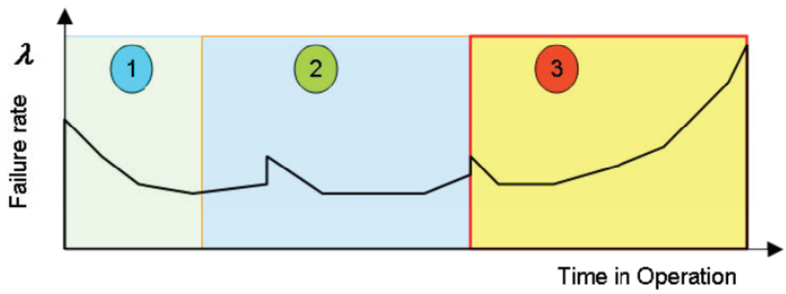


Figure 3-5 Bath-tub curve for a physical component such as a power transformer with three different lifetime phases: 1 drive-in, 2 normal operation, 3 ageing component. /95 applied/

Maintenance expenses are a function of time based and condition based maintenance, on-line diagnostics, corrective maintenance and support functions, which include spare parts' warehouses and contracts. Corrective maintenance costs are higher in critical locations when an incipient fault leads to uncontrolled failure and interruption in the electricity distribution. Preventive maintenance aims to reduce the failure rate and correct incipient faults in a controlled schedule without interruption. The importance of a certain partial system or a component comprises the reliability and consequences of a failure, expenses of the components and repair time.

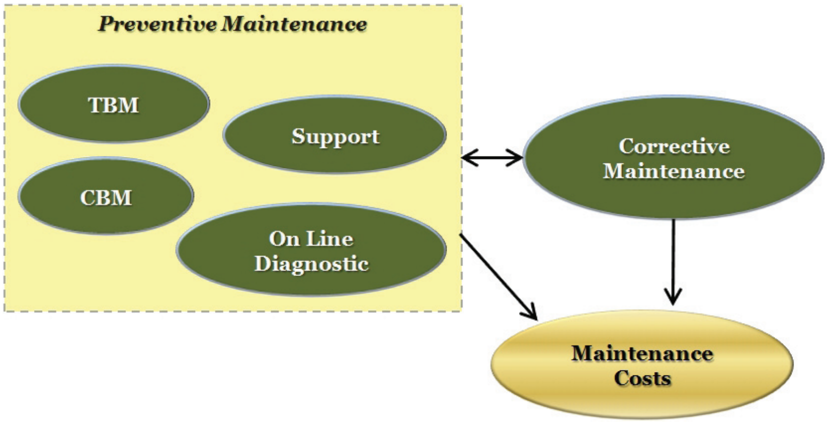


Figure 3-6 **Cost elements for overall maintenance costs and balance between preventive and corrective maintenance expenses.**

Equation for yearly maintenance costs (€):

$$C_{maitex}(y) = \left[C_{TBM} + C_{CBM} + C_{OLD_O} + C_{PM} + C_{CM} + C_{\sup\ port}\right]\frac{i_{lab}(y)}{i_{lab}(y_0)} \qquad (3.18)$$

where,

C_{TBM}	**Costs of time based maintenance**
C_{CBM}	**Costs of condition based maintenance**
C_{OLD_O}	**Costs of on-line diagnostics maintenance operation**
C_{PM}	**Costs of preventive maintenance**
C_{CM}	**Costs of corrective maintenance**
$C_{\sup\ port}$	**Costs of maintenance support systems, spare parts, warehouse**
$i_{lab}(y)$	**Index for the labour costs in the year** y

Equation for expected annual preventive and corrective maintenance costs[I] for power transformer (€):

$$\begin{aligned} C_{PM\_PT}(y) = {} & Q_{PT}\left(\lambda_{FO}(y), \beta_{PM\_fault}\right)C_{PM\_fault}(y) \\ & + Q_{PT}\left(\lambda_{SF}(y), \beta_{PM\_SF}\right)C_{PM\_SF}(y) \end{aligned} \qquad (3.19)$$

$$C_{CM\_PT}(y) = Q_{PT}(\lambda_{FO})C_{CM\_FO}(y) + Q_{PT}(\lambda_{SF})C_{CM\_SF}(y) \qquad (3.20)$$

Where,

$C_{PM\_PT}(y)$	**Expected annual costs of preventive maintenance for PT**
$C_{CM\_PT}(y)$	**Expected annual costs of corrective maintenance for PT**

I Detailed equations for power transformer unreliability and fault rates are described in Chapter 5.3.

$C_{PM\_fault}(y)$ **Costs of PM for faults in the year** y

$C_{PM\_SF}(y)$ **Costs of PM for serious faults in the year** y

Q_{PT} **Unreliability of the power transformer**

$\lambda_{FO}(y)$ **Rate for failures in the year** y

$\lambda_{SF}(y)$ **Rate for serious failures in the year** y

β_{PM_fault} **Preventive maintenance fault detection rate**

β_{PM_SF} **Preventive maintenance serious fault detection rate**

C_{CM_FO} **Costs for corrective maintenance of forced outage cases in the year** y

C_{CM_SF} **Costs for corrective maintenance in serious failure cases in the year** y

Reliability centered maintenance management is a concept which aims to balance maintenance actions on the basis of the risks and condition related to the system. Time and condition based maintenance are the central elements in the maintenance of the electrical network and the use of on-line diagnostics has increased in the past years and is still increasing. Reliability centered maintenance is used to balance maintenance strategies with costs and achieved benefits.

3.6 Quality expenses

Quality expenses comprehend electricity distribution service reliability and environmental expenses. The quality in electricity distribution can be valuated from various perspectives as there are many types customer of connected to the distribution system. One major cost factors in the city environment for an electricity network are high aesthetic standards and construction limitations. Building costs that exceed the functional requirements for a certain electricity network entity due to exquisite appearance demand are classed as aesthetics costs. For example, there are also standards for limiting noise from the electrical networks that naturally increases costs.

The reliability of the electricity supply service is the dominant part in quality expenses and it is determined by the society and many historic developments around the power system. The societal CIC-valuation for the interruptions in the electricity supply lays down the most important reference point in the asset management. The quality expenses calculation in this method aims to find the fundamental quantitative balance between accepted societal costs of electricity distribution and supply performance. The quality expense in this sense is not direct cost for DSO, but it reflects the DSO’s long-term responsibility in the society and therefore it is a better reference point in asset management than just referring to the current governmental DSO penalty levels of the supply interruptions.

In the following general function the cost of interruptions for customer C_{CIC} denotes that view. Quality expenses are calculated with a probabilistic evaluation for incipient faults that lead to failures and interruptions in the delivery.

The general parameters behind the expected quality costs for the customers due to the interruption in the supply:

$$C_{qualex}\left(C_{CIC}(t_{int}), i_{cic}(y), ENS, Q, \lambda_{system}, \beta_{PM}\right) \tag{3.21}$$

Where,

C_{qualex}	**Expected quality Costs**
C_{CIC}	**Cost of interruptions valuation of customers**
t_{int}	**Duration of interruption**
$i_{cic}(y)$	**Cost of interruption development index in the year** y
ENS	**Energy not supplied due to the interruption**
Q	**Unreliability of the system** [1]
λ_{system}	**Failure rate of the system**
β_{PM}	**Preventive maintenance fault detection rate**

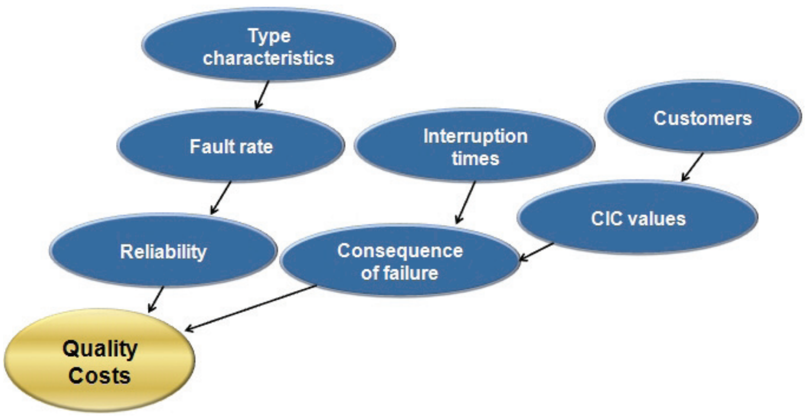


Figure 3-7 **Cost factors for reliability quality expenses.**

Supply quality costs are determined by the risk of interruptions and consequences of interruptions. The risk of interruption is related to system design and its reliability, which can be adjusted with different maintenance strategies. Online diagnostics can observe certain incipient faults before they cause an interruption, and so can reduce the failure rates that lead to uncontrolled interruption. In decision-analysis it is relevant to understand the consequences of different actions.

---

[1] Detailed equations for power transformer unreliability and fault rates are described in Chapter 5.3.

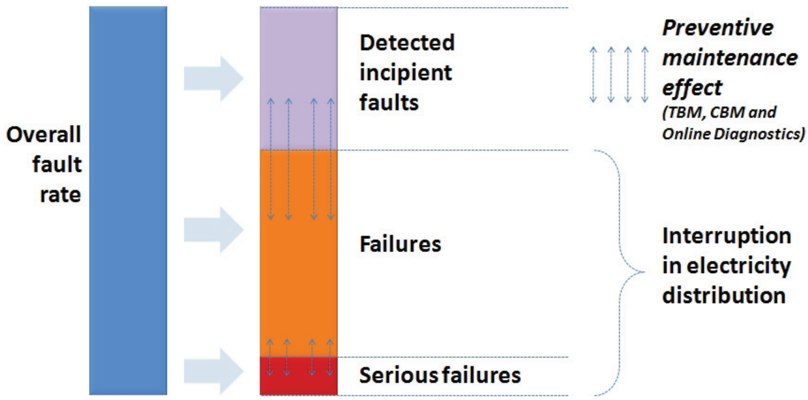


Figure 3-8 Fault rate and division into failures, serious failures and detectable incipient faults. Maintenance strategy determines the proportion of faults that lead to interruption in electricity distribution.

An incipient fault can be detected with preventive maintenance actions and fixed before it leads to interruption, so preventive maintenance reduces real failure rate. A major overhaul reduces the overall fault rate and actual failures in the same proportion. The incipient fault rate is the actual failure rate when there is no any maintenance. The following figure shows the effect of different maintenance strategies, where incipient faults are diagnosed and avoided with power transformer preventive maintenance.

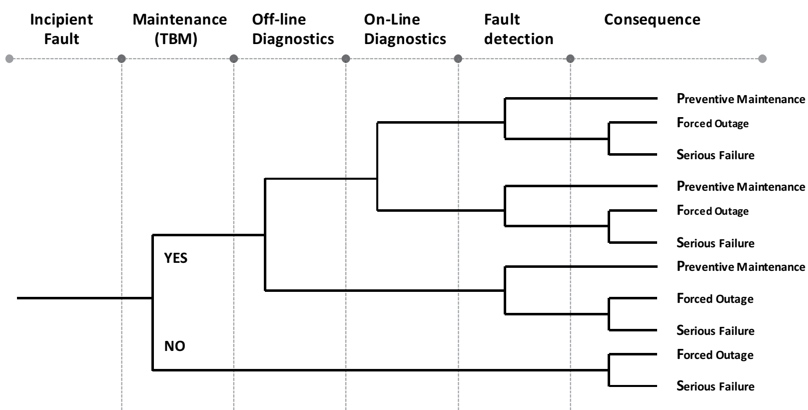


Figure 3-9 Consequences of power transformer faults with different maintenance levels and diagnostic extensions.

Faults lead eventually to preventive maintenance, forced outages or serious failures, depending on the different maintenance strategies of the system in focus. The probabilities of different outcomes are calculated for different maintenance strategies for power transformers in this thesis.

Cost function for annual quality expenses for power transformer (€):

$$C_{qualex\_PT}(y)=\left[C_{CIC\_PT}(t_{FO})Q_{PT}(\lambda_{FO}(y))+C_{CIC\_PT_X}(t_{SF})Q_{PT}(\lambda_{SF}(y))\right]\cdot P_{interrupted}(\overline{p}_{daily_X})\frac{f_{eLoadST}(y)}{f_{LoadST}(y_0)}$$

Where, (3.22)

$C_{qualex\_PT}(y)$	**Expected yearly quality cost of power transformer**
$C_{CIC\_PT}(t)$	**Cost of interruption to customers due to power transformer failure**
t_{FO}	**Interruption time of power transformer forced outage**
t_{SF}	**Interruption time of power transformer serious failure**
$\lambda_{FO}(y)$	**Annual forced outage rate of the power transformer**[I] **in the year** y
$\lambda_{SF}(y)$	**Annual serious failure rate of the power transformer**[I] **in the year** y
$P_{\text{int}\,errupted}(\overline{p}_{daily_X})$	**Interrupted electric power (daily average power)**
$Q_{PT}(\lambda(y))$	**Power transformer unreliability in the year** y **on the function of fault rate** λ
$f_{eLoadST}(y)$	**Load growth factor for the year** y
$f_{LoadST}(y_0)$	**Load growth factor for the first simulation year** y_0

Reliability increases when a system is renewed and maintained, but these are costly operations so there is a need to balance the spending with the service targets on the basis of how the customer values continuity of electricity supply.

3.6.1 Cost of Interruptions to Customers

Each customer type has varying demands for the continuity of supply and from the year 1979 the cost of interruptions has periodically been studied in Finland. At the beginning of the nineties a vast 12944 customer survey was conducted in the Nordic countries and these values are visible in Figure 3-10 below. Within some limits, historical CIC-values can be extrapolated from historical CIC-surveys, for example with general consumer price indexes or the relation between GDP and electricity consumption. This method is justified when society techno-structural development is quite even, but when new structures are implemented on a wide scale extrapolation is irrelevant. For example, society dependencies on electronics and information technologies have increased remarkably in last twenty years, so it is useful to update values with a new survey. The Newest Finnish survey on the cost of interruption to 1625 customers has been made in 2004 - 2005 and these results are the basis for evaluating interruption cost in this thesis. The following figure presents the brief history of these costs of interruptions surveys along with electricity

[I] Detailed equations for power transformer unreliability and fault rates are described in Chapter 5.3.

consumption, consumer price index and gross domestic product development in Finland. /36/

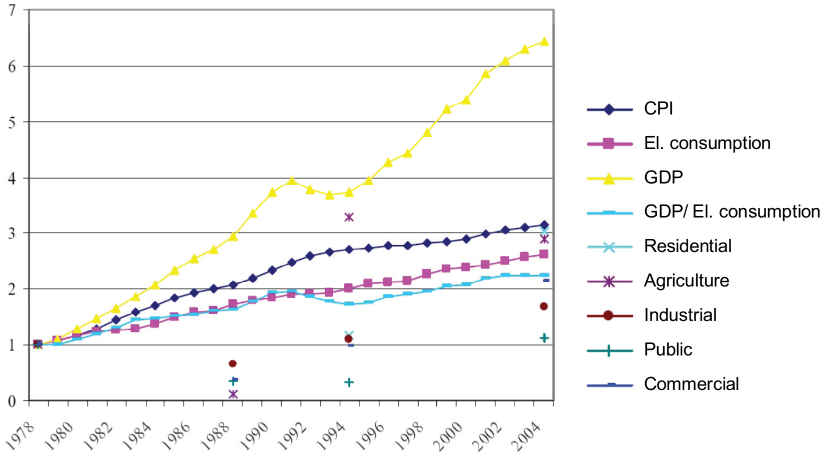


Figure 3-10 Cost of interruptions for different customers and development for the Finnish electricity consumption index, gross domestic product GDP and customer price index CPI during years 1978-2004, according to an extensive Finnish consumer survey. /36/

The development of general indexes and CIC-values do not go clearly hand in hand. Nevertheless, the consumer price index reflects the development of the cost of interruptions to residential customers and the ratio of GDP and electricity consumption reflects the commercial customer type. Notwithstanding, the linkage between CIC-values and general indexes are not unambiguously verified, but the indexes can reflect the near future development of the cost of interruptions before significant techno-structural society transformation. One visible example of the next structural step is the implementation of smart grids. The wide utilisation of distributed generation and energy storages in electric vehicles might also proportionally loosen the reliability requirement for the traditional network due the new intelligent backup systems in residential areas, for example. /36/

Naturally, the cost of interruption is dependent on many customer characteristics, hour of the day, season of the year, heating solutions, geographical location and the criticality of electricity in the dependent production or service. This complex dependency is visible in the variation of the CIC-values, although a statistically well centered mass which resembles a logarithmic normal distribution is located in the beginning of the distribution. The following table presents typical CIC-values for a range of different customer types. /36/

Table 3-2 Typical costs of interruptions scaled to peak power (€ / kW) and to variable costs for every kWh not supplied according to the Finnish survey of different customer types with one hour and 12 hour durations. /36/

Customer group	Costs € / kW		Costs € / kWh	
	1 hour	12 hour	1 hour	12 hour
Residential	3-10	25-60	3-7	2-5
Commercial	4-60	25-270	4-47	2-25
Public	5-35	60-450	5-30	5-41
Industrial	7-22	50-190	7-20	4-15
Agricultural	3-16	50-120	3-13	5-11

Definitely, the cost of interruption varies in a large scale even for the same customer type. The next figure shows the variance of interruption costs among 247 commercial customers. The clear mass between 4 to 60 €/kW from the responses is located of the beginning of the cost distribution. At the same time there are some customers which assess the interruption cost to be more than ten times higher compared to the largest respondent group of 0 to 30 €/kW. The following log-normal distribution form characterises all other customer types as well.

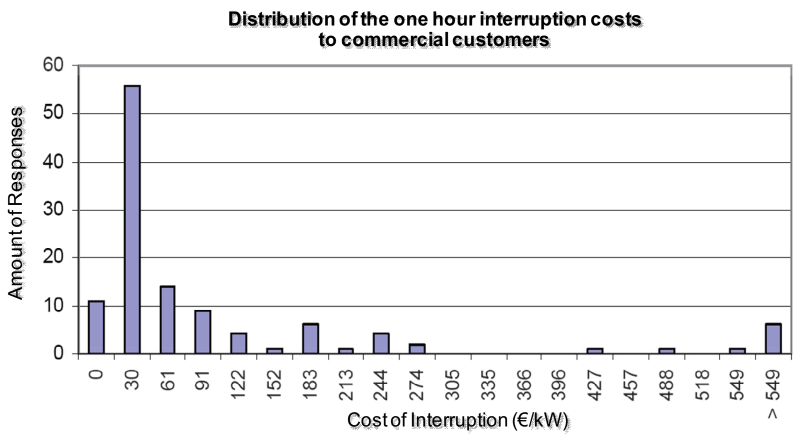


Figure 3-11 Commercial customers' (214) response distribution to unexpected one hour interruption costs. y-axis: number of responses in a certain interruption cost group, x-axis: upper limits of the costs of interruptions. /36/

The Finnish study calculated the average CIC-values in such a way where 10 % of the smallest and 10 % of the highest €/kW values were left out from the average. Interruption duration affects the monetary value for the energy not supplied: for example a commercial customer evaluates a two minute interruption energy based cost to be three times higher than the one hour interruption CIC-value. The Finnish CIC study inquired about the effect of different interruption durations: 1 second, 2 minutes, 1 hour, 12 hours and 36 hours. The three most relevant values are taken in to the Finnish CIC-baselines in this thesis in the following calculations:

Table 3-3 Finnish cost of interruptions to customer baselines ($C_{CIC\_FinBase}$). /36/

Customer group	Costs € / kW					
	2 min	15min	1 hour	4 hour	8 hour	12 hour
Residential	0,7		6,5			54,9
Commercial	5,2	13,0	48,1	139	212	281,5
Public	3,1	9,2	34,3	124	348	450,0
Industrial	2,4	6,4	21,6	76	141	189,6
Agricultural	0,9		13,2	28		148,4

Nine energy companies were involved in the latest CIC-study in Finland. Helen Electricity Network was one of those companies and obtained Helsinki area specific CIC-values. Naturally, the statistical background was smaller because Helsinki-survey included only 143 customer responses, but the information is still valuable because it shows clearly that customers evaluate the cost of interruptions higher compared to Finnish averages. For example, residential customers in Helsinki evaluate the CIC for a one hour interruption to be almost three times higher than the Finnish average. /36/

Table 3-4 Helsinki related CIC-value averages from the latest Finnish survey. (*) Exception: public CIC-value here is the median because the average differs more than decade from the all other values, (**) Exception: the commercial 2 minute CIC-value is the Finnish average because there was not enough relevant information from the Helsinki perspective in the survey. ($C_{CIC\_HelBase}$) /36/

Customer group	Costs € / kW		
	2 min	1 hour	12 hour
Residential	2,3	18	105
Commercial	5,1**	157	496
Public	15,1*	179*	432*
Industrial	12,5	35	182

In this thesis the variance of interruption costs is handled with a simple coefficient margin from the baseline. The superior and inferior interruption cost limits in the scenarios are the following:

$$C_{CIC\_\sup} = \frac{3}{2} \times C_{CIC\_Base}$$
$$C_{CIC\_\inf} = \frac{1}{2} \times C_{CIC\_Base} \qquad (3.23)$$

The Energy Market Authority of Finland has defined the official cost of interruption to customer values in the regulation model in order to evaluate the allowed DSO company profit. The official CIC-valuation for the unexpected interruptions is presented with average CIC-value, irrespective of the customer types. The Energy Market Authority's

CIC-valuation[I] for the unexpected interruptions is substantially lower than the Table 3-3 values, which are dependent of the customer types and are applied in this thesis.

Customer interruption unit costs vary with the length of the interruption. Generally the unit cost per kilowatt hour is higher when the interruption is short and decreases rapidly for the first 45 minutes. After that point the cost of interruption unit cost gradually decreases for the next 12 hours in almost all the customer groups. The public sector makes an exception when the unit cost for a 12 hour interruption is higher than for a one hour interruption. In the figure below there are indices for the customer interruption unit cost development for different customer groups on the basis of interruption length; the one hour interruption cost within each customer group is the reference level, a 60 minute interruption means a 100% level unit CIC.

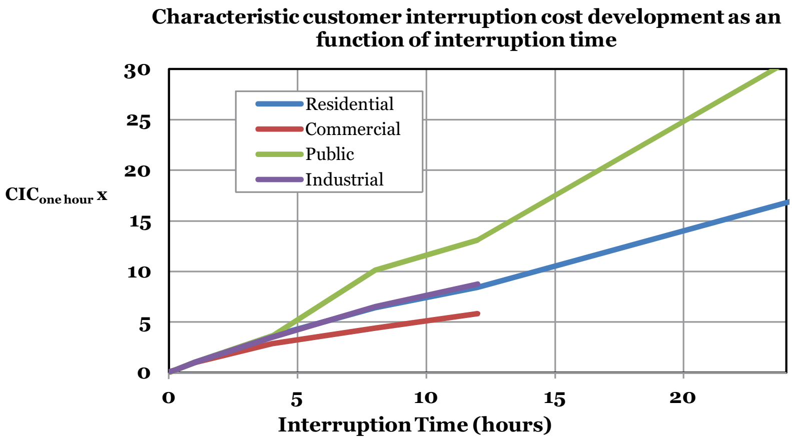


Figure 3-12 Indices for the unit customer interruption cost development as a function of interruption length. /36/

The interruption unit cost is 330 % times higher for the two minute interruption compared to the one hour interruption unit cost in all customer groups. The public consumption unit cost of interruption is 29 % higher after 24 hours. Other unit CIC-costs decrease with time, and after 24 hours the unit cost is 30 % smaller. So there is a need to separately handle public unit CIC development as a function of time from the residential, commercial and industrial customer types.

[I] The Energy Market Authority of Finland: Regulation Methods for the Assessment of Reasonableness in Pricing of Electricity Distribution Network Operations in 2012-2015, *(in Finnish)* http://www.emvi.fi/files/vp2015-2/Liite1/Liite%201%20-%20Valvontamenetelm%c3%a4t%20-%20s%c3%a4hk%c3%b6n%20jakeluverkkotoiminta%20ja%20suurj%c3%a4nnitteisen%20jakeluverkkotoiminta.pdf

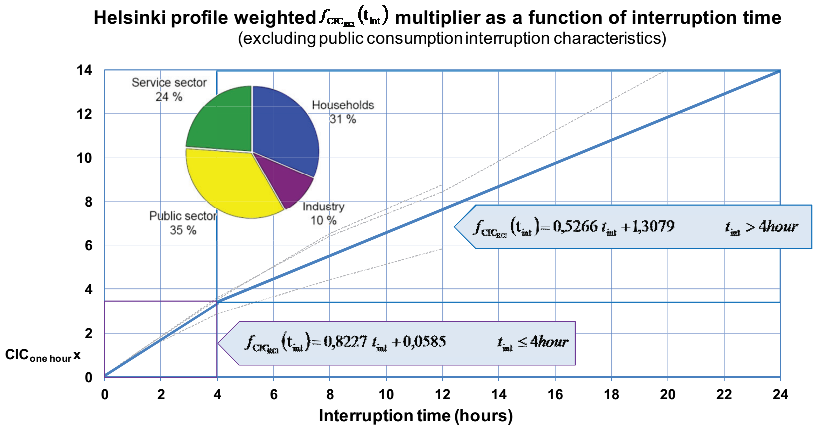


Figure 3-13 Unit cost of interruption as a function of interruption duration for residential, commercial and industrial customers. /36 applied/

The unit customer interruption cost function is important when analysing different interruption duration costs in the scenarios instead of using one constant value for all interruptions. The commercial CIC-unit cost differs 33 percent compared to the residential and industrial customer average: the unit cost is 5,9 after twelve interruption hours for commercial while the residential and industrial unit cost average is 8,6. After four interruption hours the CIC unit cost decreases and CIC unit development with time is modelled with two linear functions. Individual CIC unit points are weighted with the Helsinki customer distribution: 24 % commercial, 31 % residential and 10 % industrial customers. This evaluation gives the following CIC-unit factor for the residential, commercial and industrial consumption interruptions:

$$f_{\mathrm{CIC_{RCI}}}(\mathrm{t_{int}}) = \begin{cases} 0{,}823 t_{\mathrm{int}} + 0{,}06 & t_{\mathrm{int}} \le 4\ hour \\ 0{,}527 t_{\mathrm{int}} + 1{,}308 & t_{\mathrm{int}} > 4\ hour \end{cases} \tag{3.24}$$

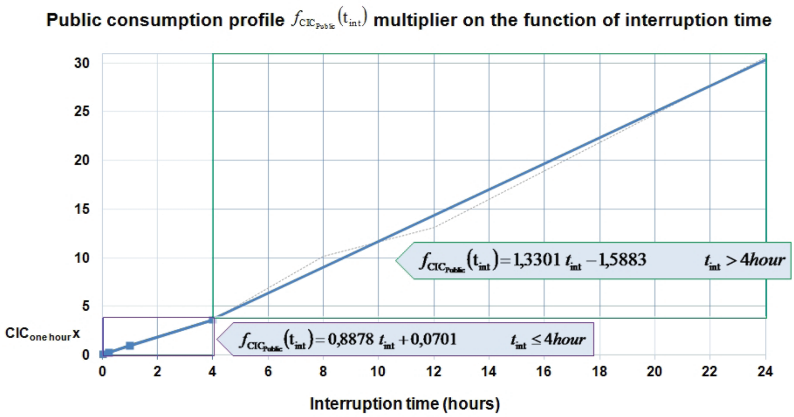


Figure 3-14 The unit cost of interruption as a function of interruption duration for the public sector. /36/

The same evaluation for the public sector gives the following CIC-unit development as a function of interruption time:

$$f_{\mathrm{CIC}_{\mathrm{public}}}(\mathrm{t}_{\mathrm{int}}) = \begin{cases} 0{,}888 t_{\mathrm{int}} + 0{,}07 & t_{\mathrm{int}} \leq 4\ hour \\ 1{,}33 t_{\mathrm{int}} - 1{,}59 & t_{\mathrm{int}} > 4\ hour \end{cases} \tag{3.25}$$

The customer interruption cost valuation also increases also over the years along with inflation and also when the dependency on the electricity supply grows in society. In the evaluations, the cost of interruption values approximately doubled within a 26 year time. Hence, yearly growth is 2,7 percent. This constant development is used in evaluating interruptions until 2030 in the base scenario evaluation.

The customer interruption cost for a power transformer unit is calculated with the following function (€/kW):

$$C_{CIC\_PT_X}(t_{int}) = \left[(c_r s_r + c_c s_c + c_i s_i + c_a s_a) f_{CIC_{RCI}}(t_{int}) + c_p s_p f_{CIC_{public}}(t_{int}) \right] \frac{i_{cic}(y)}{i_{cic}(y_0)}$$

where, (3.26)

$C_{CIC\_PT_X}$	**Cost for power transformer x interruption to customers**
t_{int}	**Interruption duration**
c_z	**Cost of one hour interruption for customer type** z
s_z	**Share of the power demand for customer type** z **from:**
r, c, i, a, p	**Residential, commercial, industrial, agricultural and public**
$i_{cic}(y)$	**Cost of interruption development index in year** y
$f_{CIC_{public}}$	**CIC-unit multiplier for public customers**
$f_{CIC_{RCI}}$	**CIC-unit multiplier for residential, commercial and industrial customers**

The customer profile is in the city centre differs from suburban residential areas, and so unit costs for interruption differ also. This difference mean in practice that cost of interruptions can be more than ten times higher in the city centre power transformer unit compared to the unit located in the sub-urban area with low loading.

4 Economic Modelling II: Economic Outlook and Scenarios for Cost Factors

The construction of energy infrastructure is directly coupled to local and global economic attributes. The state of the global economy affects general material, product and service demand, which is linked to energy demand and electrical infrastructure. Local economic attributes affect city planning and especially, privately financed activities in construction, industry and services. So the economic attributes affects electrical network asset management from many directions at the same time: energy and power demand, network expansion, component and construction costs and reliability indices.

4.1 The Reason for Scenario Modelling

An electrical network is a wide and complex system which supplies one of the fundamental needs of modern society. A distribution system operator's investment actions are related in many ways to city development, component industry, contractors and customer behaviour, and to the general state of the economy. Decisions in the transmission and distribution business have a long-term effect, and especially transmission system investments need to be considered with a quarter of the century in mind. Engineering evaluations are performed from a technical point of view, while investment portfolio optimisation is done with only partially detailed electrical equations, even though economic attributes can swing the overall result greatly. Changes in the general economy as well as in the electricity distribution business have gained more significance in the last decade. Where many essential long-term planning variables are involved in prediction and the future is turbulent, one official calculation model is not enough and scenario-thinking becomes useful. /86/

The idea in this thesis is to present a model for the techno-economical dependency mechanism in electrical networks and apply it to power transformer asset management. At its simplest this model requires scenarios for electricity demand, material and energy prices and reliability functions. Many other economical, societal and technical attributes can be in a more detailed case analysis based on the relevancy of the information. One important task is to find relevant and alternative scenarios for these evaluation attributes. Of course this is a very complicated task, especially when the scenario information aims far in to the future. That is why scenario analyses for company investments need to be made continuously with the best and most topical information available, still acknowledging the limitations of modelling and possibilities that lie outside the currently known scenarios.

4.2 Market Dynamics

One of the background reasons for this thesis is related to the increasing effects of the global markets in a DSO's business. Traditionally electrical network engineering has mainly concentrated on the technical aspects of the network development. Recent events in the material markets and construction sector have lifted the importance of economic assessment in addition to the technical details, especially when distribution businesses have been segregated into a separate limited company. Nowadays, effective network asset management requires understanding in both fields. An asset manager cannot just look at one side of the challenge. Of course there can be still special experts in the one field of the dilemma, but the overall assessment cannot be done without an understanding of both aspects.

The state of the global economy has fluctuated throughout history along with changes in the environment, science, technology, society and politics. In the last decades global economies have interconnected more deeply and changes in the economic sub-systems reflect each other with less delay, especially in export intensive countries like Finland. /67/ /29/

Figure 4-1 **Finland and World GDP per capita annual growth fluctuation between 1961-2012 according to World Bank statistics. /67/**

The Finnish economy is highly interconnected to the EU and global economies. International trade exports represent approximately one third of the national GDP. This link between Finnish exports and the world economy is visible in the figure above: the Finnish economy experience global economic shifts downwards and upwards with higher amplitude than the global average. /88/

The construction of energy infrastructure is directly coupled to local and global economic attributes. The state of the global economy affects general material, product and service demand, which is linked to energy demand and infrastructure. Local economic attributes affect city planning, especially privately financed activities in the construction, industry and services. So, the economic attributes affects electrical network asset management from many directions at the same time: energy and power demand, network expansion, component and construction costs and even electricity supply performance.

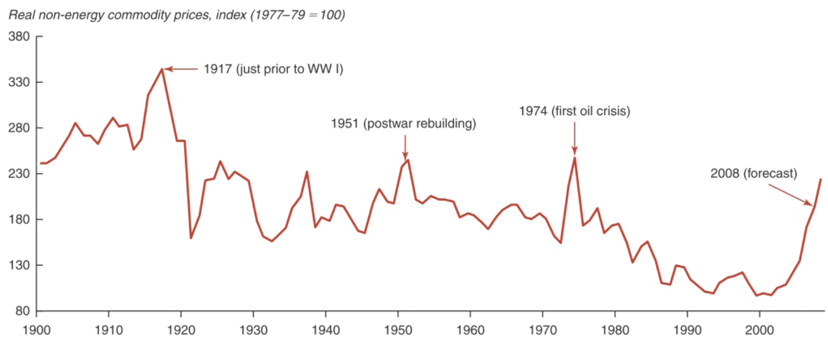


Figure 4-2 According to World Bank statistics: early 2000s commodity boom was the most significant of all commodity booms with one century in mind. /67/

Historically, building costs follow general economic development quite closely: the nineties economic recession is visible in the building cost index, although the effect is moderate. Also, the late-2000s financial crisis based recession and preceding periods of growth are convergent with the building cost index.

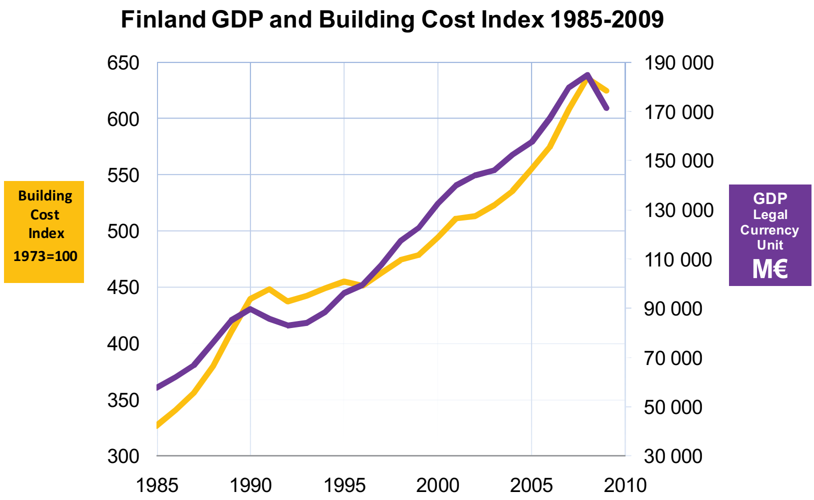


Figure 4-3 Gross domestic product and building cost index development in Finland, years 1985-2009. /89/

Network building costs are highly dependent on the cost of labour and the commodities market, especially the metal exchange. The following price scenarios are a combination of information from the forward markets and investment bank commodities scenarios. The exact price information presented here is not so relevant, because when investment decisions are made there should be the best information available, which means the most resent evaluations. Price scenarios have to be updated as a continuous process in electrical network asset management.

4.2.1 Copper

Almost all the essential electrical network components contain some base metal like copper, aluminium or iron. The electrical industries consume 42 percent of the world's copper production, therefore copper price and consumption is one general indicator of global construction activities. /34/

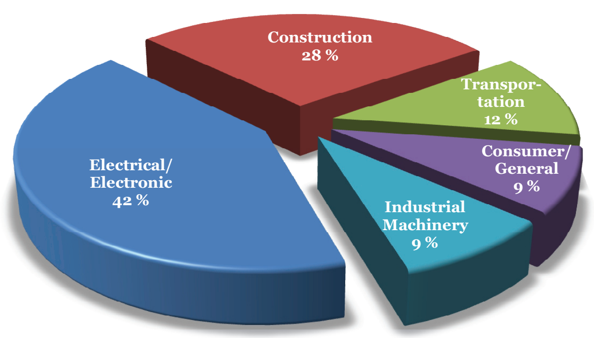


Figure 4-4 Industrial copper consumption in different areas 2007 according London Metal Exchange statistics. /34/

Copper price development was relatively stable from the eighties to beginning of the 21th century when compared to the last six years. China and India are forecast to install new electricity generation capacity at a 4,2 % average yearly growth rate between 2004 – 2030 according to International Energy Outlook 2007 /38/. Growing generation capacity and wide infrastructure development is clearly visible in the global copper exchange price for example. China's copper demand is 30 % of the world's copper consumption /37/. Network component manufacturing prices increased due to growing global demand for metals in 2005.

The next figure shows a World copper supply and demand analysis released in the 2007, and the planned refined copper production capacity increase with qualitative realisation expectancy. On the top of the supply-demand analysis there is copper price graph from London Metal Exchange: global copper demand exceeded production capacity and copper price started to rapidly grow. /28/ /34/

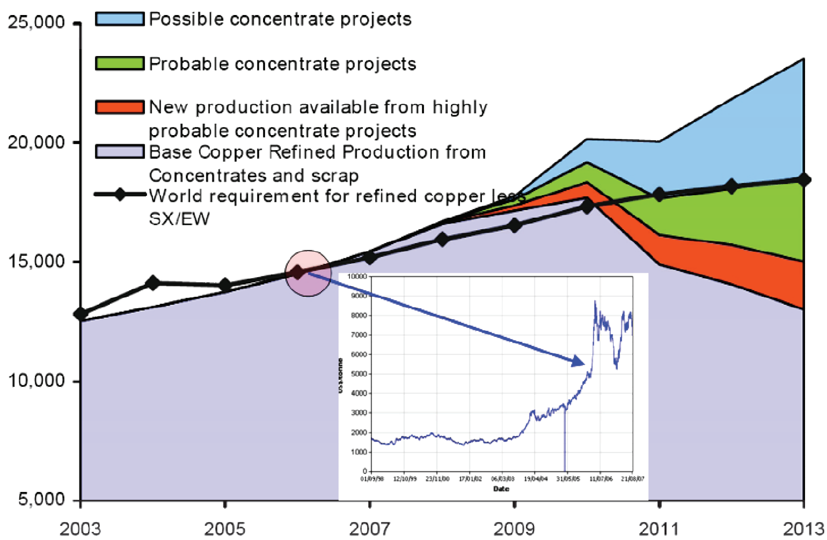


Figure 4-5 World copper supply / demand analysis made by Deutsche Bank Global Markets Research. The blue curve represents the copper price increase in the London Metal Exchange. Copper price began to naturally rise when the copper demand was higher than production capacity and global construction activities were accelerating in the economic boom. /28/ /34/

During the years 2005 to 2007 Helen Electricity Network carried out a 110 kV subtransmission network project in Helsinki, where a double overhead line was removed and replaced with an underground cable. The project required six 2000 mm² copper cables to ensure the same transmission capacity as the replaced overhead line. Altogether this subtransmission project required 99 150 kilograms of copper. The commercial offer for the cable delivery was made in September 2005 in such a way that Helen Electricity Network could fix the time for the copper price in the contract. The copper price was increasing with historical speed and so the copper price difference between the offer and the contract was 3 743 USD per ton. In this project the increase meant a 293 000 € higher cost in the one million € cable investment.

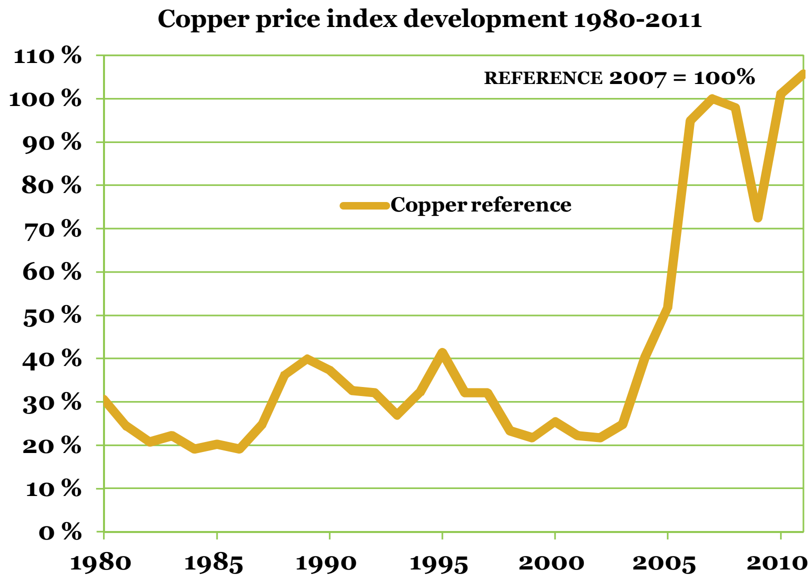


Figure 4-6 Yearly CIF (Cost, Insurance and Freight) European port copper price index development according Economy Watch statistics. /66/

One major transformer manufacturer evaluates that the share of the copper cost element is approximately 20 % of the overall unit price in the contract clause. Only a two year time difference in the company investment program can have a significant impact on the overall cost/benefit balance. Comparing the copper price effect in the years 2004 and 2006 would mean a 27 % increase in the total price. If the investment would have been delayed from the year 2008 to 2009, that would have meant a 7 % total cost reduction only considering the copper effect. Naturally it is a very complex task to estimate future price development and evaluations always include lots of uncertainty, but still it is a significant factor worth investigating along with the other investment attributes.

Global investment banks follow commodity price development as one of the core activities in the financial service sector and also industrial manufacturers are active in the field. Global financial service groups offer commodity estimate services for industrial purposes. Especially, active monitoring of fundamental commodity estimates can provide applicable information for network company medium-term planning and investment scenarios. There is also the need to acknowledge the limitations in the forecasts. Deutsche Bank Global Market Research showed that analysts tended to underestimate the copper futures market price development in the commodities price boom between 2001 and 2006. Forecasting is naturally harder during the relatively steep economic transients, especially in the years 2005 to 2006, when the copper price increased 83 percent from 3679 to 6722 USD/ton; the forecasting error was at the highest 55 percent. /28/ /67/

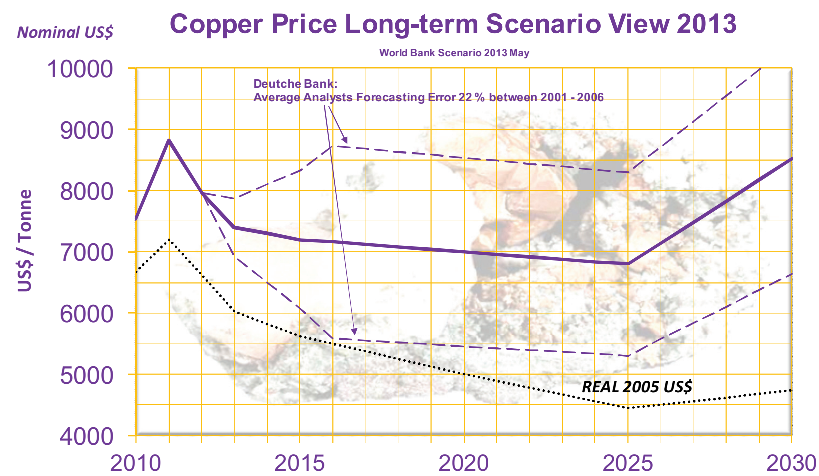


Figure 4-7 Long-term copper price development scenario according to World Bank's evaluation in May 2013. The World Bank evaluation period is from the year 2013 to 2025, from then on world historical copper price development statistics are used. /67/

The World Bank long-term price scenario is used as a base evaluation in the power transformer investment simulations. The copper price sensitivity effect on the overall results is evaluated with an average copper future market evaluation error, according to a Deutsche Bank statistical analysis in 2001-2006. Historically, the copper price has increased 4,6 percent per year from 1960 to 2010. This average increase percent is used after year 2025, which is when the World Banks fundament forecast naturally ends due to the tremendous uncertainty. /67//28/

4.2.2 Aluminium

Aluminium is one of the most common materials that electrical networks are made of. Besides the electrical properties of the material it is necessary to consider the economical perspectives in planning. Aluminium demand and price has been fluctuating along with the global economic trends, even more than copper.

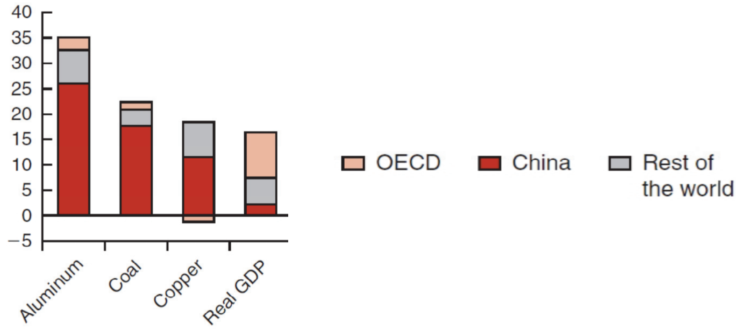


Figure 4-8 Global increase (%) in the commodity demand between 2003-2007 and contributors to this increase, especially China. /67/

Economic development in China, with expansive infrastructural and industrial investments, has been dictating the global aluminium and copper price development in the last decade. In the last decades of the 1900s price fluctuation was also significant. The primary stage of aluminium production is very energy-intensive and so the aluminium price correlation with energy price is direct. Demand has been fluctuating strongly in earlier decades: for example the collapse of the former Soviet Union in the early nineties lowered the demand in a short period of time. As along technology has developed aluminium demand has altered. Such an example can be found from aluminium as a lightweight replacement for steel. /67/

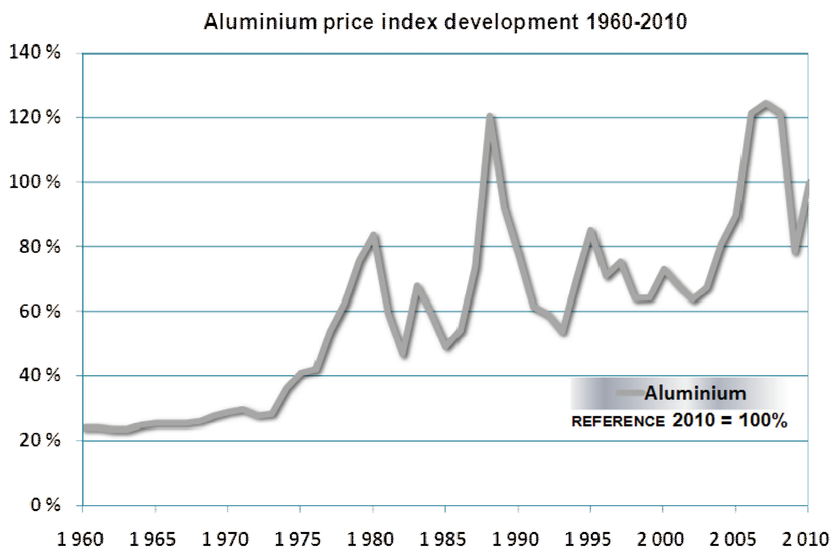


Figure 4-9 Aluminium historical price development according to World Bank statistics. /67/

The global yearly aluminium production has grown 500 % from 1965 to 2007 and at the same time the price has increased 488 % from $540 to

$2638 per metric tonne. Since 1988 the price has plunged due to the decreased demand of global heavy industries and it took seven years to recover to the 1990 demand level. Aluminium price was halved within the first three years in the early nineties global economic down-swing. /67/

Aluminium future price development is naturally a significant long-term factor in network investments and needs to be continuously monitored in investment planning. Analyst consensus aluminium price forecasts error versus real price was 10 percent between the yearly commodities boom, 2001-2006, according to a Deutsche Bank report. This error level is used as a long-term range of change in the World Bank base price scenario. /28/ /67/

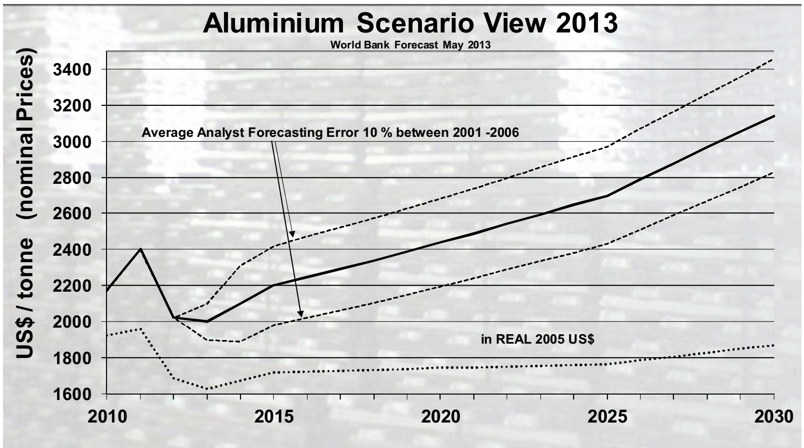
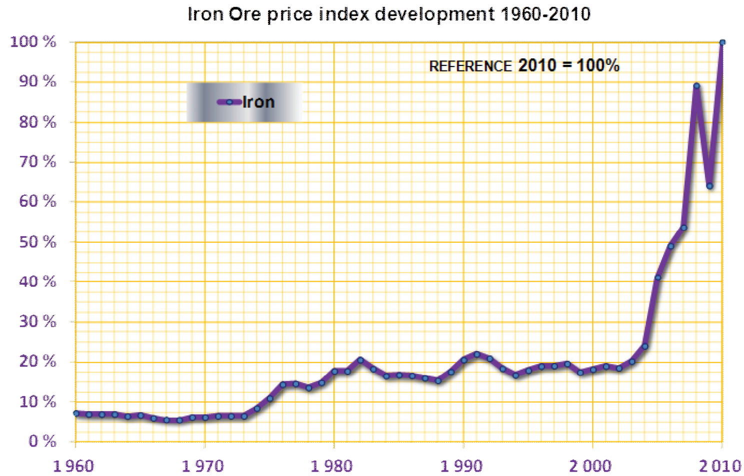


Figure 4-10 Long-term aluminium price development scenario according to the World Bank's evaluation in May 2013. The World Bank evaluation period is from the year 2013 to 2025 and after that historical average annual growth rate is used. /67/

The World Bank aluminium fundament price scenario anticipates a 33 percent increase between 2013 and 2025. After 2025 there is no relevant prediction information available and the importance of over a ten year period is less. In this evaluation after the year 2025 average aluminium price development is used for the last half century and the increase rate is 3,07 percent a year. /67/

4.2.3 Iron and Steel

Steel is used as a base material in electrical network structures and constructions in general. Steel is for the most part iron and less than two percent carbon and other substances. World crude steel production was 1527 million metric tons in 2011. Iron resources are abundant as the crust of the earth includes 5 % of iron substances and worldwide current reserves are estimated to be 180 billion tonnes. /78/



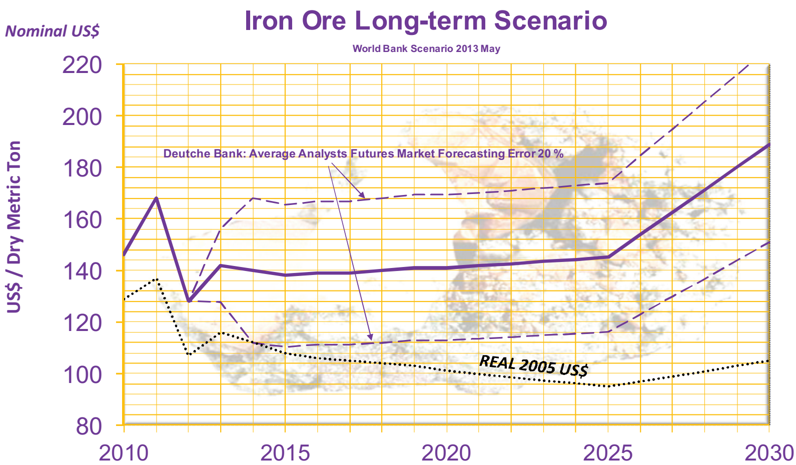


Figure 4-11 Iron ore long-term price scenario according to the World Bank and upper and lower scenario limits from the Deutsche Bank forecasting error in the commodity boom. /67/ /28/

The World Bank commodities forecast in May 2013 predicts iron ore price to be quite stable. The essential reason for this is the evaluation that there is over capacity in the sector while many large scale construction projects are on halt due to the economic situation in the western world. The steel industry is also moving more to the emerging countries. For example, in the year 2001 four of the top ten steel producers in the world were European, but in the year 2010 there was only one in the list with European headquarters. /67/ /79/

4.2.4 Energy Price Scenarios

Electrical network component life cycles are very long compared to the stability of the energy price. On many occasions the energy prices have risen to relatively higher levels that were used in the loss capitalisation analysis with current energy price. In the last decade consumer energy prices have increased faster than average consumer price growth in Finland. /90/

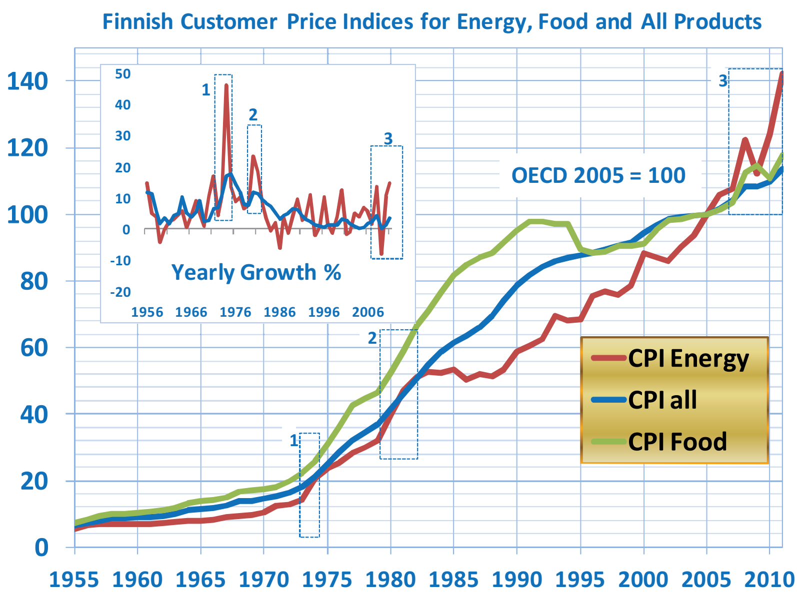


Figure 4-12 Customer Price indices development 1955-2011 for energy, food and for all products in Finland. /90/

Changes in energy price growth are faster than the food and general customer price indexes, which are visible in the upper figure areas. The energy CPI has increased 142% between 1990 and 2011 while the food CPI has increased only 24 % and total CPI 45 %. The energy price growth path is likely to continue with a relevantly volatile change rate and long term increase in the base scenario. Instead of using one constant electricity price for many decades the following scenarios are used in this thesis. /90/

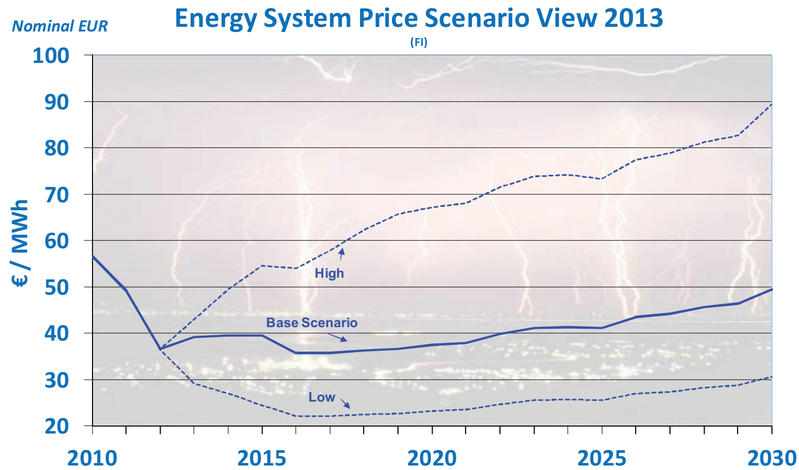
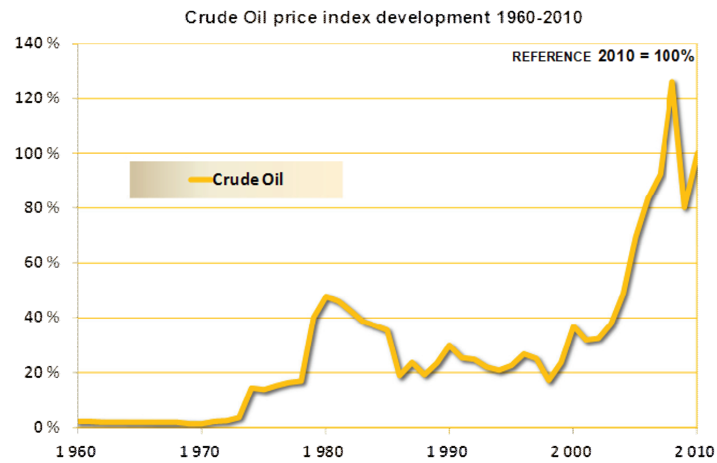


Figure 4-13 Energy system price development scenarios.

The base scenario expects a relativaly stable long-term electricity system price due to the globally slow economic growth prospect, energy efficiency, fuel pricing and low pricing for CO2 emissions. In the high scenario the electricity price increases significantly due to the increased demand and higher CO2 emission pricing. Generally the scenarios expect a power surplus in the Nordic markets due to the high investments in renewable energy sources. The low electricity price scenario expects low fuel pricing and energy demand due to the sluggish economic growth and also near zero CO2 emission pricing. Higher and lower system price scenarios represent on 80 % confidence interval for the energy system price scenario.

4.2.5 Crude Oil Scenario

Long term crude oil global demand has the widest range between low, base and high price scenarios. Oil is an essential commodity all over the world and it is sensitive to the political environment, technology development and evaluated long term production capabilities. The Deutsche Bank average analyst forecasting error related to oil future pricing was 28 % between 2001-2006. Energy efficiency measures ease oil demand growth somewhat, especially in the mature economies and later on also in developing countries, but global oil demand is still forecasted to grow 1,5 % yearly in the medium term. Historically the nominal oil price has increased from 1961 to 2010 at a yearly 8,1 percent speed and 4,6 percent in real prices. /67/ /28/ /80/



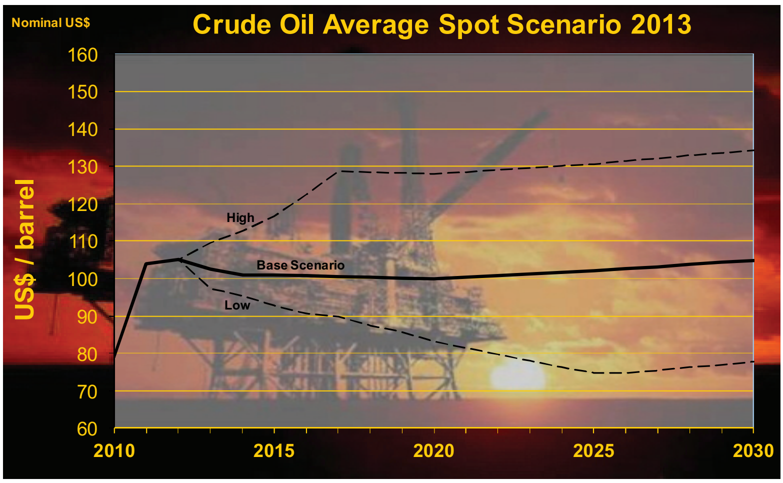
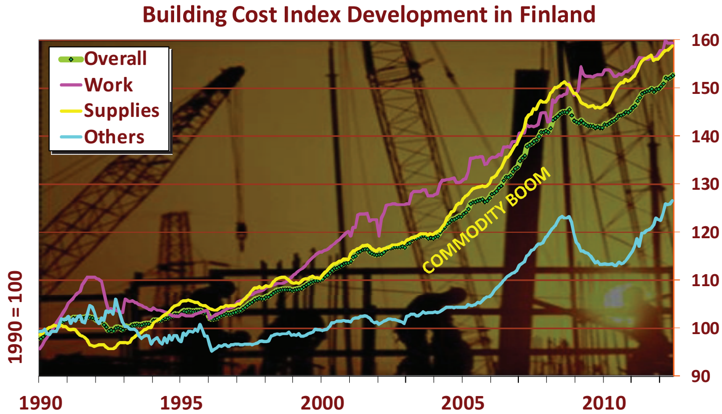


Figure 4-14 History of crude oil price index development and long-term price scenario view in 2013, with low and high price scenarios. /67/

There are three scenarios for crude oil price development that are based on different energy system development and environmental policy scenarios. The base crude oil scenario view in 2013 predicts a relatively stable average oil spot price development while the high scenario evaluates that demand growth continues and new policies increase fuel pricing. The high crude oil price scenario is also related to the energy efficiency scenario and the forecasted increase of hybrid and electric vehicles.

4.2.6 Building Cost Scenarios

Construction costs are a combination of local costs for labour, construction supplies, logistics, infrastructure connections and machinery. Besides electrical components, electrical substransmission and distribution network includes a substantial share of building construction and earthworks. Historically, the overall building cost index has increased 1,9 percent a year from the nineties and the 2001-2006 commodity boom is also visible in the supplies cost figure below. Scenarios for the building index development are comprised by local construction sector consultants for 2013-2018 and after that historical annual average growth rate is used. /89/



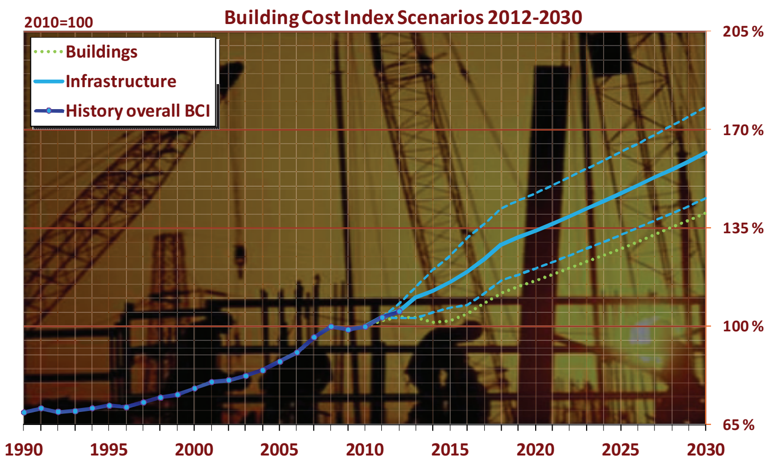


Figure 4-15 Historical building cost index development and future index scenario, 2012-2030, for infrastructure and building investments.

Local construction cost development is predicted to differ between building and infrastructure projects in this decade. The unstable global economic situation postpones new building construction while many infrastructure constructions are expected to still be realised. According to the base scenario, the infrastructure building cost index increases 34 % in this decade, and 14 % in residential and office building. Low and high BCI development scenarios are formed with a 10 % range for change, which denotes a 3-5 years long recession in the lower scenario, and increased demand and the commodity boom effect in the high scenario. /89/

4.2.7 Labour Cost Scenarios

Labour cost development is followed with the unit cost of labour for the employer. The unit labour cost is followed by the OECD, and takes cost and productivity developments into account in a way that increases in productivity reduce unit labour costs and vice versa. Industrial manufacturing and service labour cost development effect network asset management as, for example, a new power transformer price comprises approximately 40 % of the total unit price in the dynamic asset management scenarios.

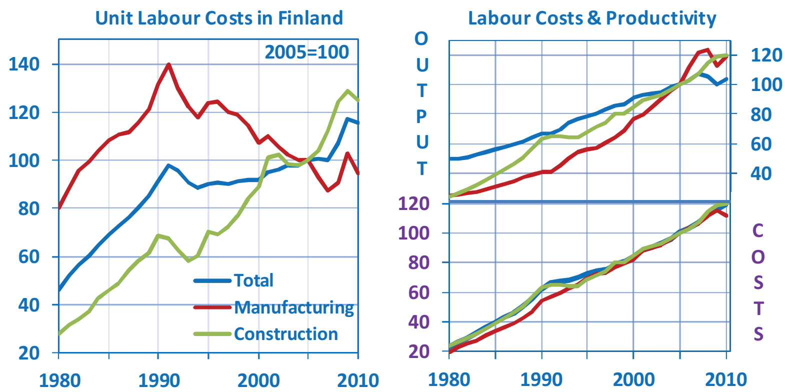


Figure 4-16 ***Left Figure:*** **Finnish unit labour cost development between 1980-2010 in manufacturing, construction sector and in total.** ***Right figure:*** **Labour compensation index per hour and productivity per hour index development. /90/**

It is noticeable that unit labour costs in the manufacturing sector have reduced by 32 percent since the year 1991 while hourly labour costs have increased 104 % over the same period. The hourly nominal labour cost increased 82 % in the construction sector and 85 % in the total Finnish economy in the same period. The Faster productivity increase development in the manufacturing sector explains the difference when comparing construction and total unit labour costs. The unit labour cost is one component of the power transformer manufacturing price and the Finnish manufacturing sector unit cost development is appropriate for measuring its history, since almost all power transformers before the 2000s were manufactured in Finland. Unit labour costs in the manufacturing sector have reduced by 2,04 % yearly on average for the last two decades, and 1,23 % yearly on average over the last decade. There is a logical reason for that since opening the economic area for competition in the EU area has increased the pressure in the manufacturing sector to reduce the high unit labour cost though productivity.

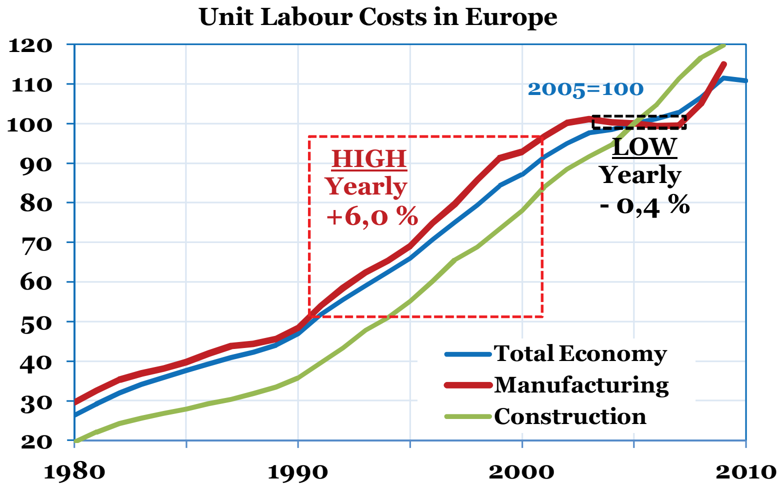


Figure 4-17 **Unit labour cost development in Europe according to OECD statistics. /90/**

During the last decade the unit labour cost has increased yearly at 2,4 % on average in the OECD European manufacturing sector and in the total economy. This type of development causes a base increase in the unit labour cost development concerning general electrical network component manufacturing. A historical low growth period in the manufacturing sector unit labour cost 2003 -2007 was -0,4 % yearly on average and during the high growth period, 1991-2001, it was +6,0 percent yearly. /90/

The applied increase/decrease for future unit labour cost development in manufacturing:

- **High growth year increase** **+ 6,00 %**
- **Base growth year increase** **+ 2,40 %**
- **Low growth year decrease** **– 0,40 %**

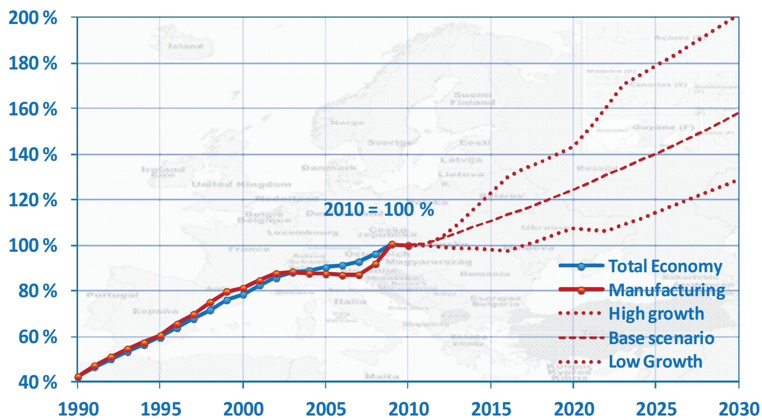


Figure 4-18 **Manufacturing unit labour cost index development scenarios in electrical network component manufacturing. /90/**

The manufacturing base unit cost development is formed using the base growth increase of 2,4 % for 2012-2030. In the high scenario, four high unit cost growth years at +6,0 percent is added to this decade and three also in the next decade. In this scenario the unit labour costs increase by 95 percent from 2012 to 2030, which is actually the same overall development compared to the historical development between the years 1992-2010. In the low unit cost scenario there is five years in this decade with a 0,4 percent decrease and two years more in the next decade. The overall unit cost growth is 30 % in the low scenario and 53 % in the base scenario between 2012 and 2030.

4.2.8 Global Economic Frame Scenarios

Global economic future development sums up factors beyond the accurate analytical models treated here. Several economic worldwide organisations and national institutions follow the fundaments of global economic development closely and try to comprehend the effects of different alteration factors to the organisation's economic frame. The power system asset manager is not required to create a complex world economy analysis, but merely monitor global economy effects on physical systems and reflect on future planning with several relevant scenarios available. Global economic framing can help to evaluate large characteristics in the development, such as the demand for commodities and energy and the scale of new construction.

This thesis allusively applies global economy scenarios produced by the Finnish Business and Policy Forum EVA to frame possible construction activity levels and general economic trends. The EVA Forum evaluates global long-term future development with four scenarios: A Comeback of the west, Chinese capitalism, Battle of the blocks, and Stimulus and collapse. Although these scenarios were prepared in 2008 and 2009, they can still frame the global economy in the first part of this decade. /76/

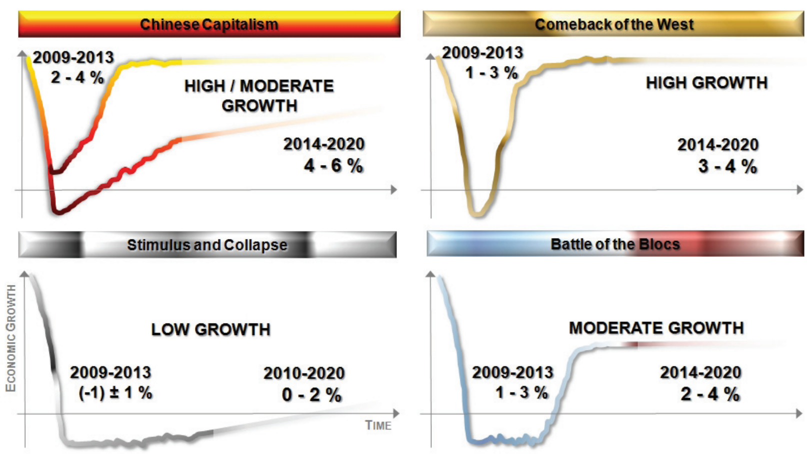


Figure 4-19 Four global economic development scenarios and average of world GDP growth formed by the Finnish Policy Forum EVA. The following

curves describe different paths from the economic recession in the late 2000s to rapid recovery or sluggish progress in this decade. /76 applied/

Scenario Comeback of the west emphasises functional market economy and democracy development under the leadership of western countries. International financial and political institutions are successfully reformed and more transparent fiscal policies are in place while productivity is increasing and new efficiency technologies are applied in society. In this scenario the commodities prices are high due the high demand and the requirement for environmentally friendlier politics. **Scenario Chinese capitalism** highlights the shift of economic power to Asia and Middle Eastern OPEC countries. Opportunistic capitalism is increasing at the cost of democracy decrease and international institutions are weaker in affecting the global politics. Asia and Middle Eastern countries drive global economic development and the rest will follow. There are good opportunities for market and expertise based networks while the significance of individual states decreases. Economic growth is high for the leaders in this scenario and moderate for followers behind. Commodities prices are high due to the high demand. **Scenario Stimulus and Collapse** assumes that the political recovery measures in United States and the European Union would not stimulate the economy into a growth path and no country or bloc can take the leadership position in the global economy. Global recession leads to protectionism and weaker international cooperative structures and also to inflation. Economic growth is sluggish or even negative. **Scenario Battle of blocs** describes development path from failed stimulus efforts to regional trade blocs and a shift from international market transactions to state capitalism. Europe is a new focal point for economic reforms while US is taking steps inwards away from international cooperation. Localised and more isolated economies lead to only moderate global economic growth. /76 applied/

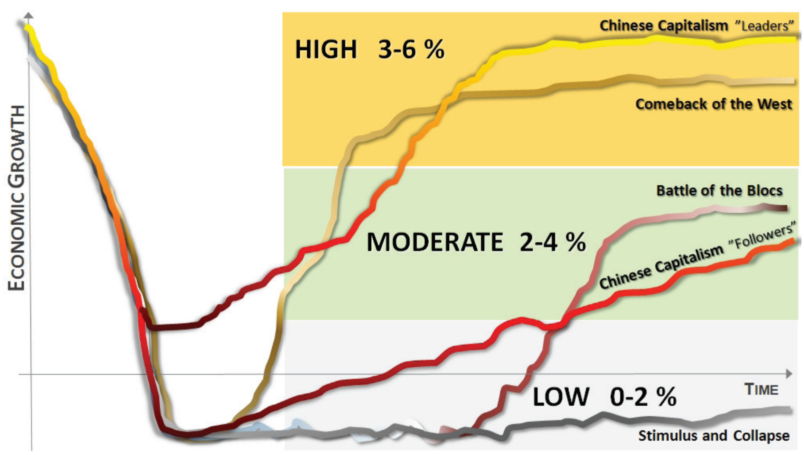


Figure 4-20 Global economic GDP growth in four EVA scenarios in three levels. /76 applied/

Global demand of commodities, construction activities in Helsinki and construction cost level alter in the presented scenarios. Comeback of the west is a high growth scenario from the Helsinki city point of view, where global growth is 3-4 percent around 2020 and city construction is fast. In the Chinese capitalism scenario construction activity in Helsinki is moderate as the more eastern based economy decreases the demand for office premises in Helsinki, while residential building output is high due to the continuing urbanisation megatrend. The Stimulus and collapse scenario leads to a relative decrease in the construction activities in Helsinki when global economic growth is near zero, which actually did happen in the nineties economic recession in Finland, although in this scenario the recovery takes longer. /76 applied/

4.2.9 Interest Rates in Asset Management

Choosing general interest rates when assessing long-term network asset management expenditures is essential, because the applied interest rate determines the time value of money on behalf of the customers. Applied interest rates reflect the valuation of general economic development and societal expectations for the distribution system operator. The thirty page Electricity Market Act states the word "reasonable" 21 times and according to legislation the evaluation of reasonable profits is the responsibility of the National Electricity Market Authority /6/. The general interest rate for an asset manager making long-term assessments is comprised of the real weighted average cost of capital and evaluation of the long-term inflation. The governmental regulator defines the reasonable weighted average cost of capital for the distribution system operator, which is based on the relatively risk-free interest rate of 10-year government bonds, the regulator guideline for the DSO financial structure and regulator defined reasonable profit rate levels for equity and debt. The regulator has stated the reasonable real weighted average cost of capital on a yearly basis. For the corporate tax obligated distribution system operator this has been around three to six percent depending on the economic situation. /45/

Table 4-1 Reasonable profit levels stated by the Electricity Market Authority of Finland. /45/

(%)	2006	2007	2008	2009	2010	2011	2012	2013
Weighted Average Cost of Capital	4,73	5,29	5,65	5,78	5,26	4,45	4,58	3,19

The economic valuation determines the fundamentals from which the interest rates in the calculation are derived. For the long-term asset manager, the applied interest rates should reflect the customers' time value of money because the customers pay everything in the end. Asset cost functions in the dynamic scenario modelling in this thesis reflect the future expenditure side of asset management in nominal values and so the payer side should be assessed with the nominal rate as well. The nominal interest rate is a function of the real interest rate and expected inflation rate. The inflation rate from the payer's side is based on the Euro area all-inclusive harmonised index for consumer prices. The European Commission statistics show that the yearly all-inclusive harmonised index for consumer price inflation has been 1,9 % between 1997/01 – 2013/05 in Finland and 2,1 % in the whole European Union. The European Central Bank objective is to keep "inflation rates below, but close to, 2 % over the medium term". Because of the ECB objective, the baseline evaluation for inflation is formed around this statement within ±0,25 % boundaries. The baseline WACC is the regulator's current directive for the year 2013. Currently the governmental reference interest rate is at a historic low[I], and so the lower WACC is chosen to be 0,5 % lower than the base value and the higher rate 1,0% higher than the base rate. /2/ /46/

Table 4-2 Nominal interest rates used in the long-term asset management scenario evaluations.

	WACC	Inflation	Nominal Rate of Interest
Base	3,19 %	2,0 %	**5,25 %**
Low	2,69 %	1,75 %	**4,49 %**
High	5,00 %	2,25 %	**7,36 %**

Applied interest rates and price expectations in the thesis scenarios are formed around a relatively stable economic system, but when there is the need, the scenario analyses can be made in situations where global economic structural changes cause significant transients in the global economy.

4.3 Electricity Consumption Scenarios

A network asset manager needs to foresee the future demands of the electrical transmission and distribution for pertinent investment decision-making. Electrical consumption prediction is a crucial part in asset management, because it forms the basis of the investment plan. An electrical load forecast has to provide information about where, when and in which magnitude power needs to be delivered. This chapter presents how an electricity use scenario is constructed for later use in the investment scenarios. /75/

Electricity demand has followed economic growth for the last century in Finland and in Helsinki. Energy politics, society planning and technology

---

I Yield on 10-year government bonds was 1,71 % between 1.1.2013-10.7.2013.

http://www.suomenpankki.fi/en/tilastot/arvopaperitilastot/Pages/tilastot_arvopaperimarkkinat_velkapaperit_viitelainojen_korot_en.aspx#Pe6b2c2888a6348198d4eee95e5600aca_2_39iT0R0x0 development represent the main drivers for the future electricity demand. The main drivers of future demand are in the period of transition due to the increased overall requirement for the energy system. Global energy policy points to energy efficiency and new low-emission energy technology, and also to the integration of the energy system and ICT. City planning forms the backbone of the energy system and urban city expansion requires significant long-term planning. Future electricity demand is possible to predict with relative accuracy by following the city zoning plan, characteristic consumption behaviour and new technology development and roll out scenarios. /68/

The general state of the economy affects the load development. The last economic recession in Finland in the years 1991 to 1993 can be seen from the peak load values: there is no load growth, but no significant decrease either in the recent recession.

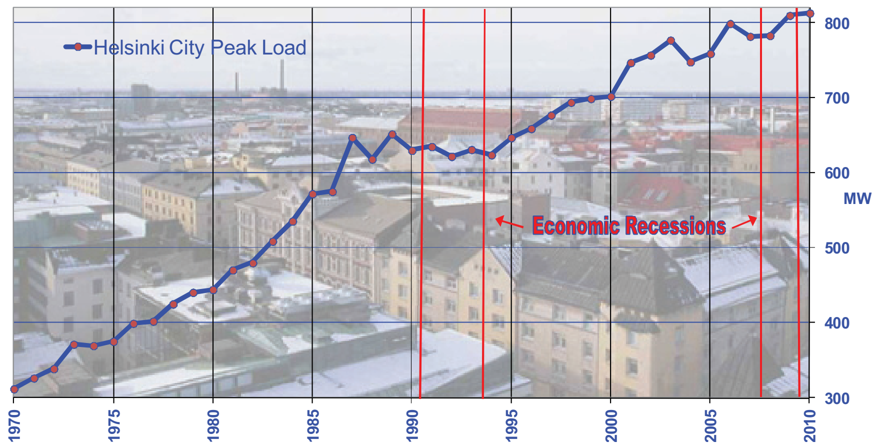


Figure 4-21 Helsinki city yearly peak load excluding the internal consumption of the power plants in the city. Load growth stopped due the economic recession in the beginning of the 90s. The latest financial crisis recession effect has been very small on peak load.

City expansion is sluggish in the economic recession, especially privately financed ventures are on hold. Central government and public authorities can set up stimulus packages to balance local economic cycles. Essential infrastructure projects are a central target for stimulus packages.

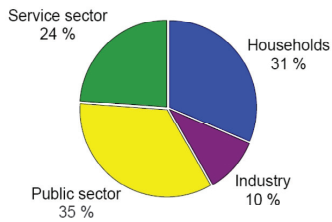


Figure 4-22 Customer types in Helsinki

Industrial load is usually the most sensitive to economic fluctuation but the share of heavy industrial load in Helsinki is scarce, only 10 percent. Naturally, the commercial service sector is more sensitive to economic fluctuation than the public sector and household consumption. The Helsinki customer type distribution is the reason why electricity demand did not stall on a large scale in the early 90's recession. Public sector and residential consumption require structural changes for significantly different characteristic consumption behaviour. Increasing automation, smart grids and electric vehicles represent significant new elements of change in the future electricity demand and these aspects are evaluated in the energy efficiency scenario.

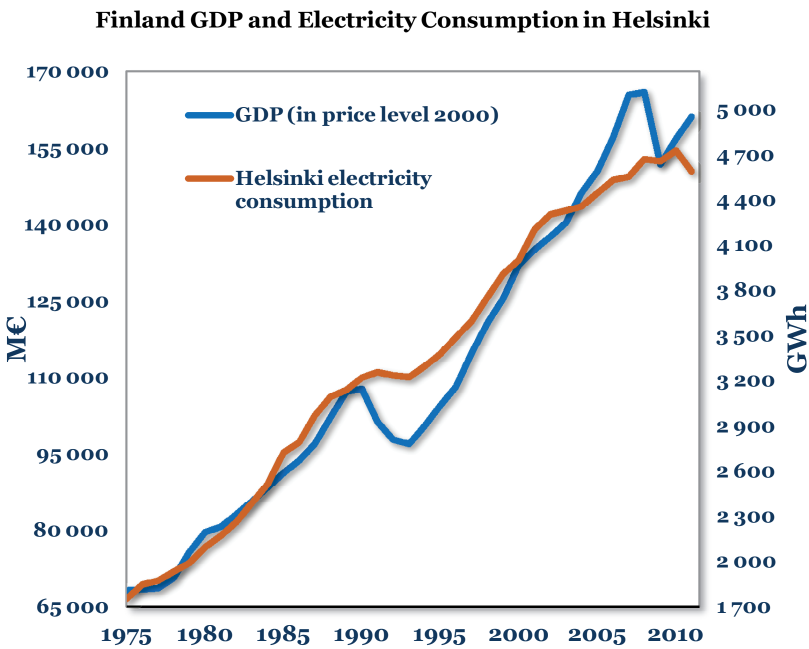


Figure 4-23 Finnish gross domestic product and electricity energy consumption in Helsinki between 1975-2009. /89/

In Helsinki, the overall electric energy consumption sensitivity to gross domestic product is similar to peak power development, although energy consumption development stagnation is slightly shorter from both ends. The Finnish ministry of employment and the economy evaluated that it is probable that the growth of the national economy and electricity consumption development correlation mechanism with change; i.e., an increased national economy may not necessary lead to increased electricity consumption with such a tight correlation as shown in history and which is visible at the end of the last decade. /89/

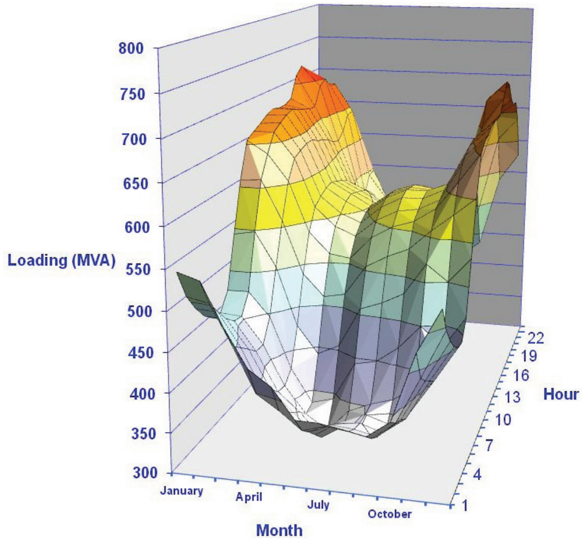


Figure 4-24 On the Helsinki annual three dimensional load profile: monthly load variation X-Y axis is due the thermal effect of the four seasons and in the Z-Y axis daily variation due the rhythm of day-to-day life.

Electricity consumption future scenarios have a wide distribution and the reason for that is that there are many things happening at the same time in the energy sector. Climate change issues have directed focus on decreasing carbon dioxide emissions and there are many major players in this field. Various methods are presented for solving the problem, comprising mixtures of political, technical, societal and commercial interests. Electrical load forecast is fundamental to future long term network planning and it is necessary to sketch consumption development around 25 years ahead. Transmission system investments require the longest perspective in planning because investments are high and decisions concerning the transmission system somewhat dictate the solutions applied later in the lower system levels. Substations require space and the more densely populated the area in question is the longer the time needed for land use reservations. 10 to 20 years ahead is the normal lead time from the first sketch to an operational substation in metropolitan city planning. Distribution and customer-level planning is done in shorter time scales under the general city zoning plan.

Figure 4-25 Time frames and hierarchy for network load forecasting at different network system levels. /75/

There are two basic principles for the construction of an electrical network load forecast: trending, which extrapolates historical load growth into the future and simulation, which tries to model the load growth process itself. The land use simulation method is a good option when society planning is performed with a high spatial resolution. In Helsinki, the network load forecasting model is build upon Helsinki region spatiotemporal land use information. This thesis applies Helen Network's spatiotemporal load forecasting model developed by Markku Hyvärinen, Antti Rautiainen, Jussi Palola and Pirjo Heine. /75/

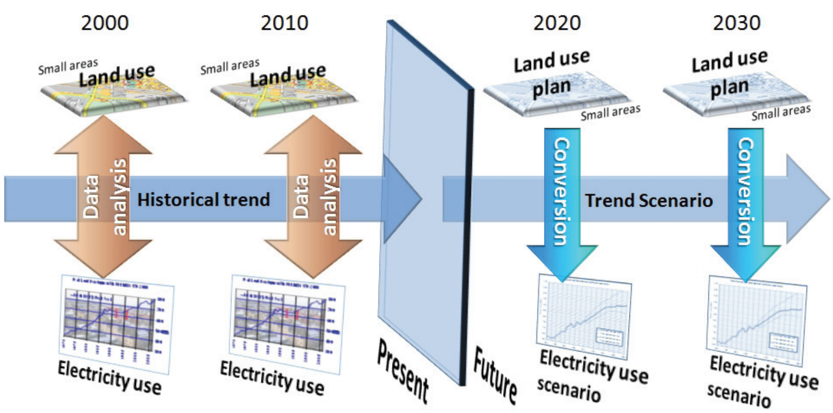


Figure 4-26 The outline for the load forecast land use simulation model, where the land use plan is converted to an electricity use scenario. /75/

A historical electricity use trend was analysed in the 125 small city areas of Helsinki City for different customer types. In this analysis seven customer types were classified: temporary constructions, residential, office premises, community services, public transportation, outdoor lighting, and agricultural. Land use and customer classified usage information was then combined with the city small area plan and converted to create a future scenario for electrical demand.

Initial data for the Helen Electricity load forecast:

- Current network structure
- Historical loading information
- Existing buildings and future city planning
- Expected changes in the consumption behaviour
- Large individual consumption points (Metro, Computer Server Halls, Large pumps)

4.3.1 Future City Construction Scenarios

Helsinki city planning department is responsible for the future city zoning. Helsinki zoning is divided in eight grand districts, which are further divided into 34 primary districts and 125 small areas. The new grand Östersundom district was integrated to Helsinki city in 2009, but Helen Electricity Network Ltd. is not the DSO responsible for this new area and so it is left out from the analysis.

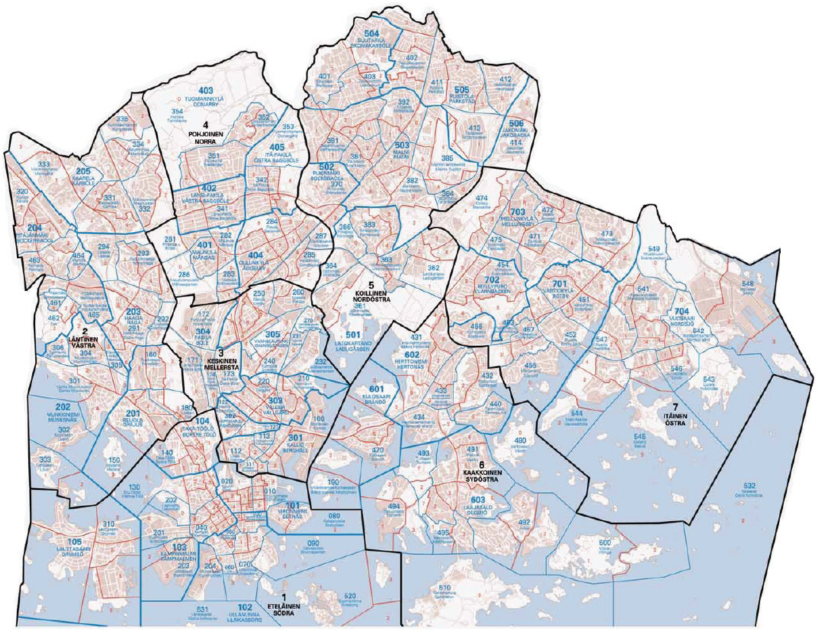


Figure 4-27 Helsinki division into districts used in the Helen Electricity Network ltd's load forecast. /Helsinki Surveying department[I]/

[I] City of Helsinki Urban Facts - statistics http://www.hel.fi/hki/tieke/en/Etusivu

In Helsinki currently there are altogether 44,6 million floor square meters in 45 000 buildings. The current city development base plan for the year 2020 includes a 17 percent increase in the new housing and office premises compared to 2008. The general construction plan until 2020 zones 4,9 million floor m^2 for housing and 2,9 million floor m^2 for office premises. A development plan is given in small area resolution, which is sufficient for detailed spatiotemporal load growth simulation modelling. New small area plans are converted to electricity use on the basis of local area characteristics and are connected to the electric network model.

Construction activity is sensitive to economic fluctuations: for example in the year 2010 housing activity increased approximately 50 percent compared to the situation a year earlier in Finland and in Helsinki it increased even more with 57 %[I]. Three Helsinki construction scenarios are used in electricity demand evaluation in this thesis on top of different global economic growth scenarios. Usually, the larger the area in the GDP - construction activity relation evaluation is used, the more tightly the construction activity and GDP development correlates: total construction comprised 7 % of the whole area GDP in Western Europe in 2004 and an even higher share in the rapidly developing countries. /69/ /77/

Figure 4-28 Construction activity year-to-year development and GDP growth in Finland 1990-2011 with two economic recessions. /89/

The construction activity level is related to GDP and there are economic policy modelling publications that handle this relation with detailed causality models in both directions: how GDP affects construction output and vice versa. In this thesis, global economic growth frame scenarios are applied to evaluate possible construction activity levels in Helsinki and

---

[I] City of Helsinki Urban Facts - statistics http://www.hel.fi/hki/tieke/en/Etusivu not the other way around. In the Finnish economy, industrial and service export dominates GDP with 40 %, and is very sensitive to global economic growth. The nineties' and latest economic recessions are clearly visible in the upper figure above from Finland's perspective: construction activity decreased 20 percent in almost every recession year. The total Finnish construction activity is more sensitive to GDP than to Europe level diagram.

Office premise demand is particularly sensitively related to global economic growth whereas residential construction activity is more stable. This is taken into account in the Helsinki construction scenarios. There are other aspects besides economic growth, such as urbanisation trends, to explain the construction activity level in Helsinki. Construction activity scenarios are based on the Helsinki City Planning Department general zoning plan and base scenario. The slow construction scenario is comprised from the city department's base scenario with economic recession effects from the latest recessions in Finland. /77/

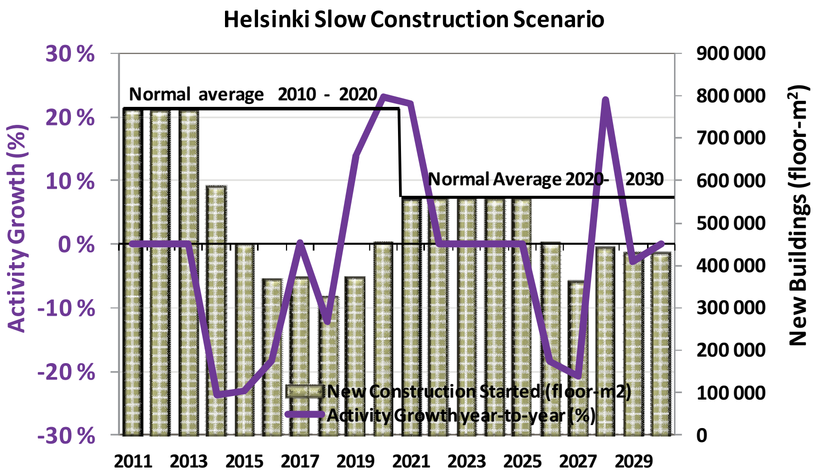


Figure 4-29 Slow construction scenario formed from the normal construction scenario with two economic recession periods, in 2014-2018 and in 2026-2027. /89/

In the slow construction scenario only 53 percent of the general zoning plan is realised in 2011-2020 and 65 percent between 2021-2030. The first recession, 2014-2018, which resembles the nineties recession, postpones construction activities by 3,2 years on average. The second recession in 2026-2027 resembles the latest 2008 financial crisis with a shorter recession and it postpones construction projects by 1,2 years on average.

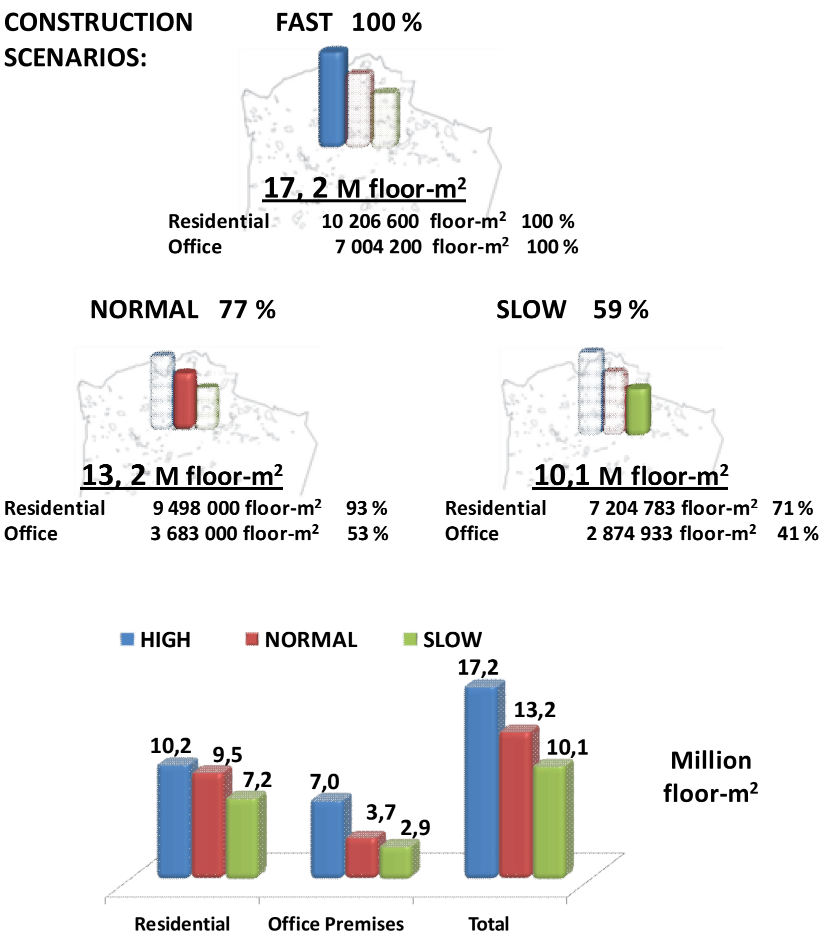


Figure 4-30 **Helsinki new residential and office construction scenarios 2011-2030.**

CONSTRUCTION ACTIVITY SCENARIOS:

HIGH: The whole city zoning potential is constructed right on time: **100%** zoning is realised with a fast construction phase without delay over the next seventeen years.

NORMAL: Helsinki City Planning Department base construction scenario in normal economic conditions: 93 % from residential zoning and 53 % from office premise zoning is realised from the 2030 city general plan and **77 %** overall.

SLOW: All construction activities are postponed for five years from the base scenario due to sluggish global economic development. 71 % from residential zoning and 41 % from office premise zoning is realised from the 2030 city general plan, and **59 %** in overall.

The next thing is to evaluate changes in the consumption characteristics for the coming years. Specific consumption measures for different customer types are recorded into the customer information system. Statistical data clearly shows that cooling demand has and is still increasing in Helsinki. The district cooling system adds significant individual load points in the network. The metropolitan subway traffic system is expanding and new subway substations have been introduced to the model. Electric vehicles are coming and adding a growing need for electricity in the coming decades. Newly planned large computer halls require several megawatts of network capacity as does the Vuosaari harbour's high power vessel electricity land feed. The loading forecast model is made with these characteristic measures in future city development scenarios and reservation is made for large individual consumption points.

4.3.2 Characteristic Consumption Behaviour Prediction

Electricity consumption behaviour is under continuous development, especially when fundamental structural changes in the society are advancing. For the next twenty years new elements will increase the electricity characteristic demand, such as electric mobility and when higher comfort requirements in air-conditioning become common. The progress in energy efficiency can also increase the use of electricity when for example, inferior efficiency systems are replaced with new electricity based solutions. Current consumption behaviour is analysed spatially with the classification of customer types in the small areas.

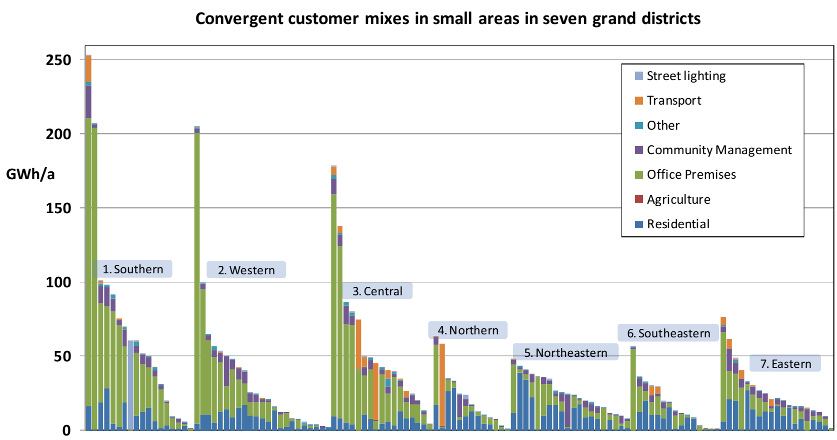


Figure 4-31 Helsinki customer energy consumption mixes in small areas. /74/

Commercial and public services are significantly concentrated in the city centre and nearby areas in the southern, western and central grand districts. Residential consumption is widely distributed in all the areas although the grand districts four to seven, which are located farther from the city centre, are predominantly residential. Public transport connections are large individual load points from the electrical network point of view and are taken into account separately. /74/

The city development plan is described in two major categories: future residential and office premises. Residential and office consumption information is spatially analysed in the small area scale and used to model consumption in the planned zoning with the energy efficiency effect. Future community management and street lighting, which are more evenly distributed, are extrapolated for the future constructions using an average value. Smart meters can be applied fully for more accurate consumption behaviour monitoring and prediction in the near future, as the first generation smart meters are in place in Finland.

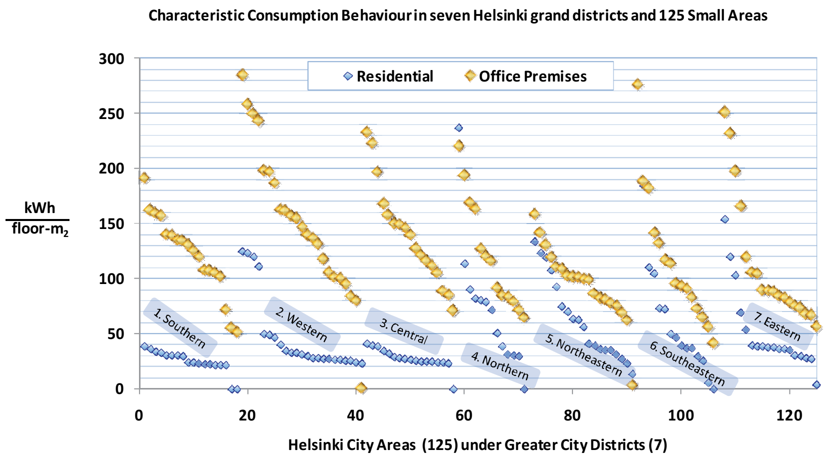


Figure 4-32 Helsinki small area characteristic consumption behaviour information for residential and office premises in order of magnitude under Helsinki seven grand districts. This information is the basis for the evaluation of the characteristic demand of future projects in the small areas.

Average residential characteristic consumption is 49,3 kWh / floor-m^2 and 130,8 kWh / floor-m^2 in office premises. The characteristic consumption standard deviation is high among the 125 small areas, which is visible in the figure above: the deviation is 65 % for residential consumption and in the office premises it is 46 % from the average. The reason for this high deviation is the different customer mixtures in the areas. Future changes in the consumption behaviour are assessed with the energy efficiency scenario. /74/

4.3.3 Electric Vehicle Generalisation Scenarios

Global environmental targets in the transport sector and the development of energy storages in transport are pointing towards the electrification of road transport along with an expanding public electric transport system. Several public administration entities are contributing to promote electric mobility. The Finnish ministry of employment and economy formed a task group to evaluate possible scenarios for the wide introduction of electric vehicles and later on the Electric Vehicle System development program to enhance R&D in this field between 2011-2015. Helen Electricity Network's early assessment for electric vehicle charging energy is based on the estimated amount of electric vehicles according to VTT SGEM indicative studies /75/, Helsinki vehicle fleet characteristics, average yearly driving kilometres and electric vehicle consumption. The evaluation of the electricity consumption of electric vehicles in Helsinki is the following: the introduction of electric vehicles starts in this decade with extended range electric vehicles and plug-in hybrid vehicles, and with a relatively smaller share of battery electric vehicles.

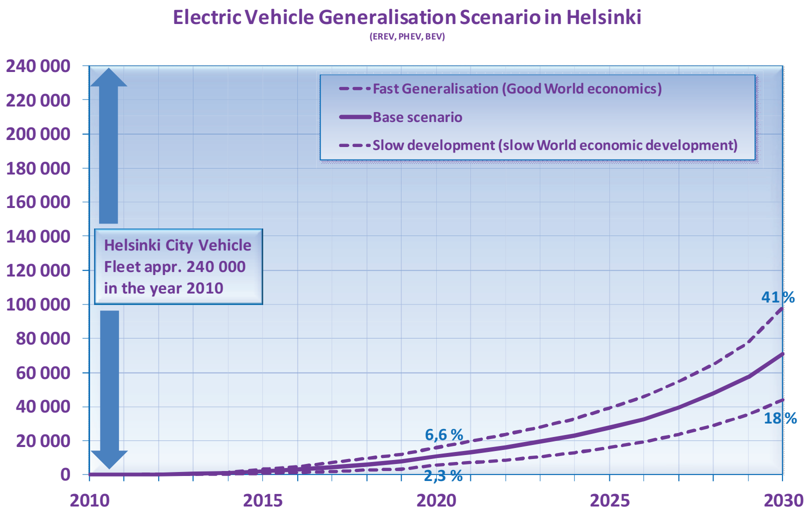


Figure 4-33 Electric vehicle scenarios in Helsinki. /73 applied/

There are approximately 240 000 registered cars in Helsinki in the year 2010 and the car fleet density is 40 % compared to the city population. The electric vehicle penetration with reach a 2,3 to 6,6 percent share at the end of this decade according to the scenarios. Large-scale electric vehicle deployment speeds up in the next decade and penetration is largely affected by the general global economic situation: in the slow-growing scenario the electric vehicle share will reach the 18 % level, while a favourable economic trend and technology development can speed up EV penetration to nearly half of the operational car fleet. /73/

Electric vehicle consumption is evaluated assuming 0,2 kWh/km and the yearly driving distance grows from 18 000 km/year to 20 600 km/year level. The plug-in hybrid and extended electric vehicles share for electric drive is assumed to be 80 % in the scenario evaluation. /73/

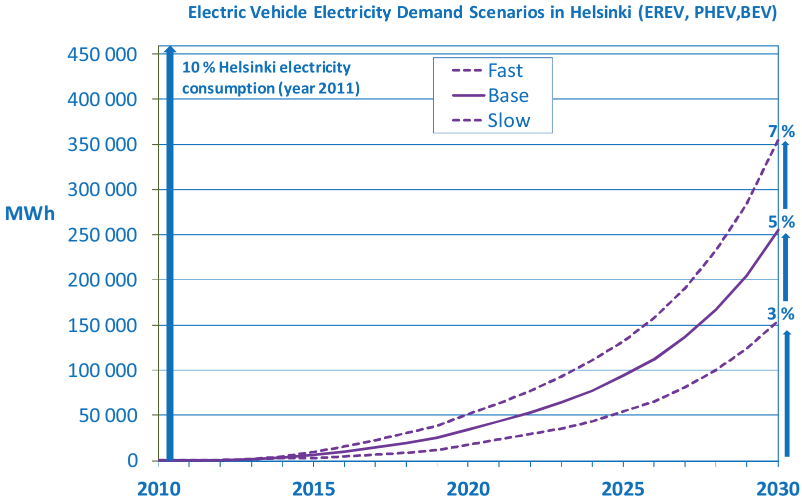


Figure 4-34 Electric vehicle electricity consumption scenarios in Helsinki. /73 applied/

The deployment of electric vehicles will increase Helsinki city's overall electricity consumption by 3 to 7 percent in the year 2030. This is one clear example that increasing energy efficiency leads to electricity consumption increase as overall energy efficiency is significantly enhanced when internal combustion engine is replaced by plug-in hybrid or electric vehicle.

4.3.4 Energy Efficiency Scenario

Energy efficiency by definition aims to reduce characteristic energy consumption in such a way that systems or products produce the same service with less energy. Energy efficiency development is a combination of political, technological and societal processes: significant political instruments aim to affect change in societal structure and consumer behaviour while technological development offers new tools for it. The combination of new energy technologies and policies are influencing peak load development and energy consumption gradually. The energy efficiency of electric devices reduces peak power and overall energy demand even while new electrical devices are connected to the distribution network. /49/

The European Commission announced an energy efficiency action plan with the view to reduce primary energy consumption by 20 % by 2020. The Finnish government is implementing the European Commission action points in the Finnish long-term climate and energy strategy, which is used here to build an energy efficiency scenario in the Helsinki electricity network area. The Finnish Ministry of Economy and Employment published governmental targets in energy efficiency and these targets are used to create the efficiency scenario for Helsinki electricity consumption. Electricity consumption can increase at the same when energy efficiency is promoted, so it is also necessary to evaluate possible increase in the electricity consumption in the scenario. /70/ /71/ /73/

Table 4-3 Finnish Government energy efficiency objectives for the electricity consumption use in following sectors. Percent figures describe the evaluated energy efficiency objectives compared to 2020 baseline consumption. /71/

Residential	13 %
Electric heating	20 %
Service sector	11 %
Other	0 %
Industry and Construction	0 %
Overall efficiency target 2020	5 %
Overall efficiency target 2050	31 %

Governmental electricity energy efficiency objectives are used in the following scenario for the cumulative development of the characteristic consumption behaviour. The Finnish governmental vision for long-term electricity energy efficiency is to lower characteristic consumption by 5 percent by 2020 and by 31 percent by 2050. The Characteristic consumption reduction between 2020 and 2030 is linearly interpolated from the 2020 and 2050 figures and it is -13 percent in the year 2030. This target is applied as the ground scenario for the highest energy efficiency development scenario. On top of that, fast electric vehicle penetration electricity consumption is added as it represents the highest energy efficiency development path. /71/

Low Cumulative: Full governmental efficiency target + fast penetration of electric vehicles

Base Cumulative: Half of the efficiency target is reached + base scenario for electric vehicles

High Cumulative: Electric efficiency stays the same + low electric vehicles scenario

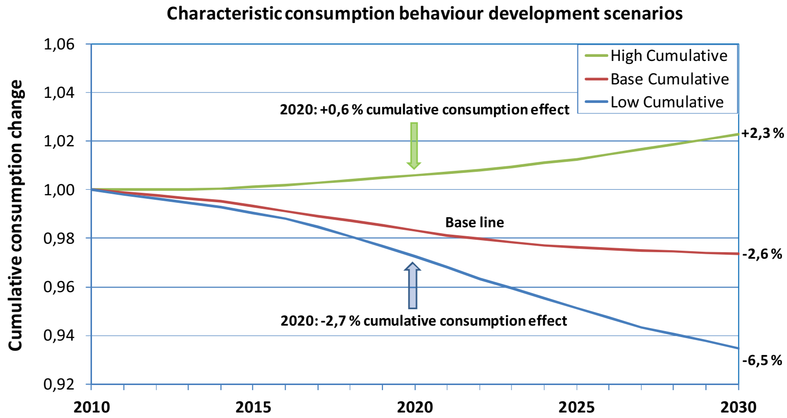


Figure 4-35 Energy efficiency scenario and characteristic consumption development, baseline and high consumption increase, scenario. /71/ /73 applied/

The lowest cumulative characteristic consumption development reaches -2,7 percent in 2020 and -6,5 percent in 2030 in Helsinki. This level means a 62 MW peak load reduction in the Helsinki area slow construction scenario due to the energy efficiency by the year 2030. The highest cumulative characteristic consumption development scenario evaluates general electricity efficiency development to be zero and adds consumption of the electric vehicles from the lowest deployment scenario. This scenario also means an overall enhancement in the energy efficiency, but still electricity characteristic consumption slightly increases by +2,3 percent cumulatively until the year 2030.

Dynamic demand response offers a relevant way to limit peak load development. In Helen Electricity Network distribution area the controllable night-heating loads alone are 70 MW. Commercial demand response, customer energy storage and customers' own electricity generation will change the load development characteristics along with energy efficiency progress. The introduction of electric vehicles, distributed generation and demand response are expected to fit into the overall energy efficiency scenarios presented above when concerning consumption development at the power transformer level. In general, for DSOs it is reasonable to follow these developments closely because changes in energy politics can accelerate these effects more than currently expected./48/ /49/

4.3.5 Electricity demand scenarios

The electricity demand scenario is comprised of these main components: historical consumption information and characteristics, city building information and future scenarios for construction, consumption characteristic change scenarios and future individual large load points.

The base construction scenario without energy efficiency measures increases Helsinki peak load from 813 MW to 1003 MW within twenty years, and with slow construction to 964 MW. The high construction scenario is realised when all zoning is constructed on time and in this scenario the peak load will rise to 1102 MW in 2030. There is bigger difference between the base and high scenario than between the base and low scenario because the high scenario includes a much higher share of new office and commercial premises, where the characteristic consumption per square metre is relatively higher compared to residential consumption. In the figure below there are peak load scenarios with and without efficiency scenarios.

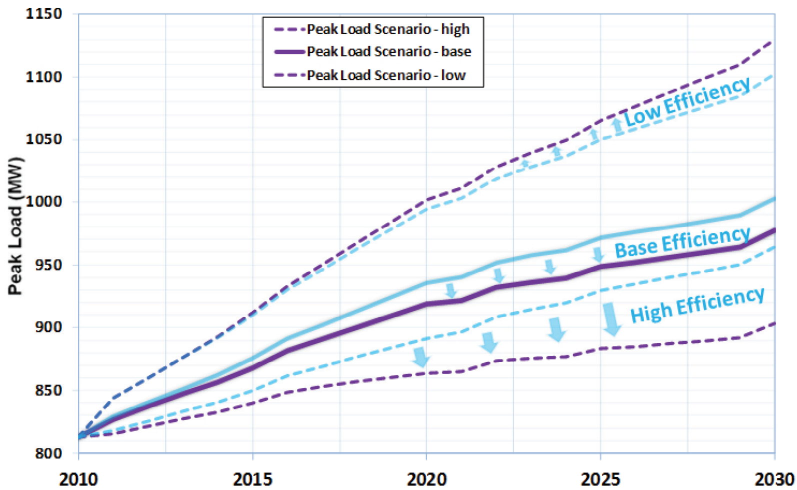


Figure 4-36 Helsinki peak load development scenarios: light blue curves denote peak load development without efficiency scenarios and purple with efficiency effects.

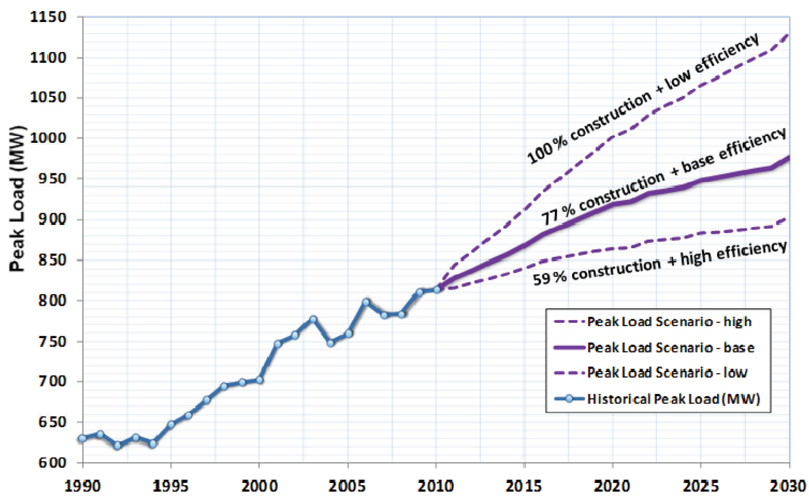


Figure 4-37 Historical Helsinki Peak load and future development scenarios, which are used in the asset management evaluations.

The base scenario peak load develops at quite the same rate it has developed for in the last decades in example, to 977 megawatts in 2030. The peak load difference is 227 MW in 2030 between the high and low overall scenario due to the different construction phase and efficiency development. Electricity demand scenarios are connected to electricity network structure and to every power transformer in the dynamic scenario model.

5 Asset Modelling: Case Power Transformers

On top of the distribution system asset management scenarios, there is need for the dynamic modelling of the assets in focus. This chapter comprises a dynamic model for DSO power transformer assets in reliability, maintenance, usage, investment economics, and criticality.

5.1 Power Transformer Scenario Assessment

Deterministic decision analysis has been used for many years to schedule power transformer major overhauls and new unit investments. Usually it works out fine, with sufficient reliability marginal and robust economic measures, but there is unused potential which a deterministic analysis does not analytically utilise. A periodically monitored power transformer unit in a harsh environment can approach and even across the operational danger zone limit imperceptibly when the asset manager is relying on deterministic timing and average reliability margins. A deterministic analysis is based on time intervals: for example, a transformer lifetime is evaluated to be 30 to 40 years and with major overhaul 40 to 50 years – but major overhaul is usually carried out on transformers that have been 20 to 30 years in network operation in Finland.

At least four remarkable factors have changed the thinking in power transformer asset management and in electrical networks in general during recent years.

- Turbulence of global economic trends and material prices
- Incorporation of the distribution system operation business in Finland
- Technology and price development of ICT solutions for energy systems
- Increased demand for electrical network reliability

Turbulence in economic trends and in material prices means alteration in power transformer prices as well. For example, one power transformer price clause states that the total sales price is tied to the copper price index development with a 20% coefficient. The London Metals Exchange statistics show a 3-month buyer copper price increase from 3200 to 7000 USD within one year, 2005 to 2006. This radical copper price effect would increase the copper 0,20 coefficient to 0,44 and the total power transformer price by 24 % only due to the copper price increase. /34/

The incorporation of the DSO business has given more pressure for the company's anticipatory financial design. The long-term pertinent investment budget enables reasonable financial actions and saves the company financial expenses. ICT development affects power transformer asset management through online condition monitoring. Online monitoring equipment prices have decreased significantly and the number of different online condition monitoring products has increased in the last ten years. This technology can offer new and timely information for decision-making and that information is needed to increase or maintain reliability and for lowering the overall expenses. /59/

The dynamic scenario assessment model takes the earlier mentioned factors in account from the DSO point of view. International research has presented more detailed models for the evaluation of one or two particular factors in power system asset management from a scientific point of view, for example in transformer reliability modelling. This thesis draws results from many international findings in such a way that the model is still controllable and comprehensive, which means that it cannot be comprehensive and meticulously detailed at the same time, for the sake of usability.

Dynamic scenario analysis can aid to make more precise decisions concerning transformer investments, major overhauls, condition management and monitoring benefits. The newest transformer fault statistics and enhanced diagnostics provide crucial information from the unit's life-cycle. The transformer operational life concept applied in this thesis is three dimensional: technical, economical and strategic lifetime /35/. The aim is to build dynamic model for power transformer asset management which combines technical and economic aspects together, in order to make more pertinent decisions. The base for the transformer investment planning is built on the following ten factors:

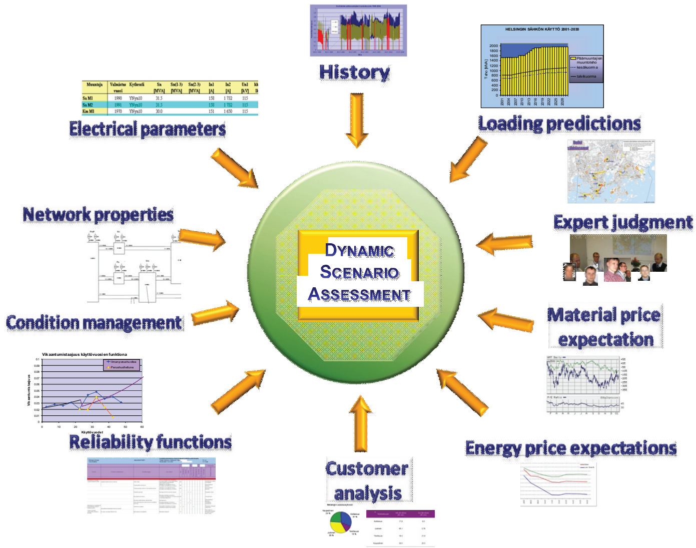


Figure 5-1 Factors comprising the dynamic scenario modelling for power transformer asset management.

- ***Electrical parameters***	***- Operational history***
- ***Loading predictions***	***- Network properties***
- ***Reliability functions***	***- Expert judgement***
- ***Material price expectation***	***- Energy price expectation***
- ***Customer analysis***	***- Condition Management***

The dynamic scenario assessment is built to model long-term asset management performance in different economic environment scenarios. The most important factors are: loading prediction, transformer reliability functions, customer analysis and expert judgement assessing initial data correctness, adjustments and model suitability for the specific case.

5.2 Power Transformer Fleet Asset in Focus

An example analysis is made for Helen Electricity Network's current power transformer assets and future scheduled investments, on the basis of new substation construction plans. The power transformer asset replacement cost is 25 million Euros and the present value is 11 million Euros.

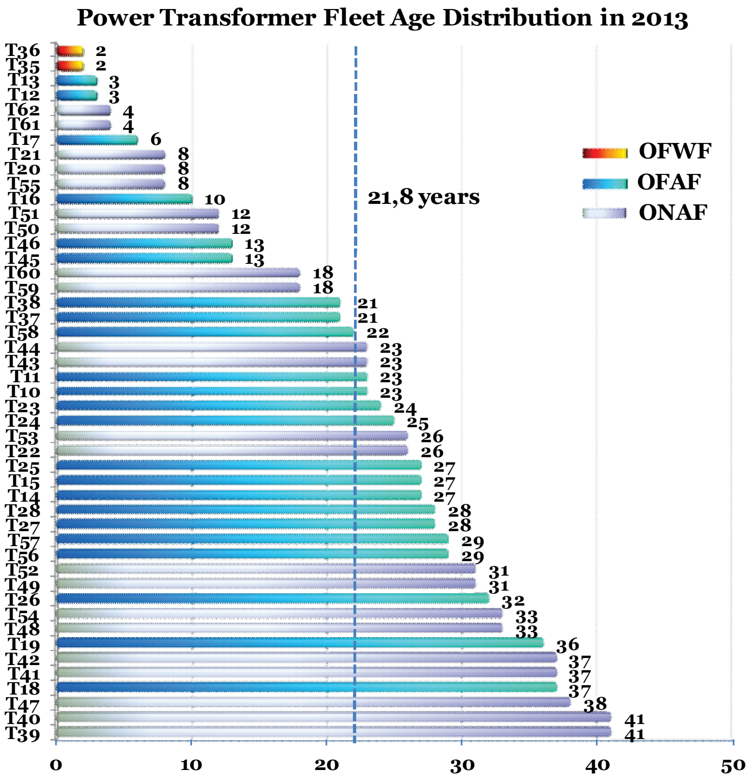


Figure 5-2 **Helen Electricity Network power transformer fleet age distribution in 2012 and applied cooling system which is described in the Appendix 1.**

There are 47 power transformers in operation in the year 2013 and the fleet average time in operation is 21,8 years. Voltage levels are 110/10kV in 21 units and 110/20 kV for 26 units. The most common cooling system is oil forced air forced OFAF in 23 units, because this structure is more suitable in a densely built city environment. The two newest units in a downtown underground substation are cooled with a district cooling, oil forced water forced system due to the space limitations. The rest of the 22 units are oil natural air forced systems in more spacious locations. Figure 5-2 shows the power transformer fleet age distribution and cooling system design. The reason for noticing the cooling system design is related to the transformer ageing of OFAF cooled transformers due to the higher operational temperatures compared to ONAF units.

Electricity demand is increasing even in the Helsinki low growth scenario and five new substations are planned to supply the demand. According to the network expansion plan there is a need for nine new power transformer sites. In addition, old units are renewed all the time and so 20-25 units will reach the end of their operational life cycle in the following eighteen years, depending on the renewal age.

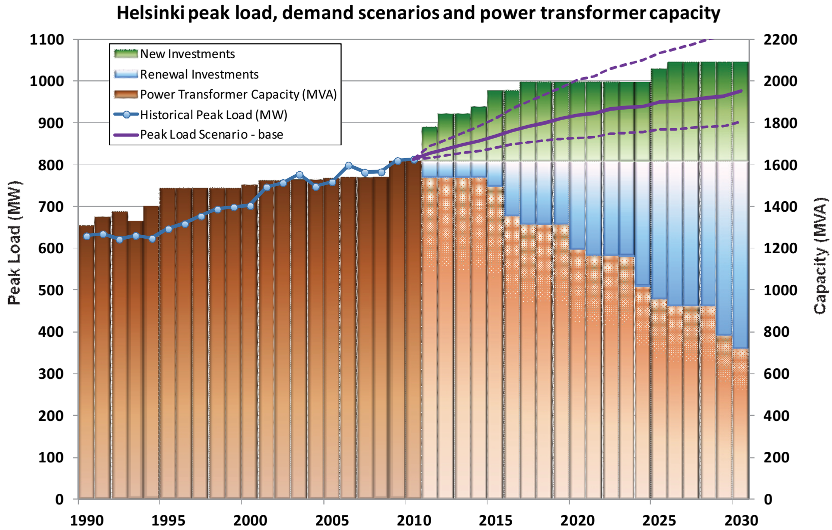


Figure 5-3 Helsinki peak load history and future scenarios with the left y-axis (MW) and historical and future planned power transformer capacity with right side y-axis (MVA).

In the year 2010 the power transformer capacity was 1618,5 MVA in Helsinki while the peak load was 813 MW. Power transformer capacity is roughly two times greater than the peak load value due to the reliability requirement. According to the deterministic investment plan, 818 MVA transformer capacity is renewed (light blue in the figure above) and 469 MVA capacity is added to the Helsinki area network (green pylons in the figure). The planned capacity is easily sufficient if the lower or base future electricity demand scenarios are realised and there could still be need for new capacity if the high electricity demand scenario is realised. It is probable that commercial demand response mechanisms will increase in the evaluation period, which will limit the unit peak loading. Distributed generation, electric vehicle utilisation and demand response are expected to be included in the intensive energy efficiency scenario, which gives the lowest consumption forecast in the upper figure. The analysis is made with the current 47 power transformer sites plus nine planned new sites.

5.3 Reliability model

One challenge is to get good information that is suitable for modelling the transformers with specific characteristic information. The following reliability model combines survey results from three sources. Cigre and Fortum Service statistics are used together to approximate the transformer failure rate between operation years 0-40. RTE's statistics are used to evaluate the share of the serious faults from forced outage anomalies and the forced outage rate at the end of normal operation.

- Cigre international survey on power transformer failure statistics /51/
- Fortum Service transformer fault research in Finland /87/
- France RTE's transformer fleet failure statistics /65/

An exponential function is used to approximate the power transformer failure rate statistics. Transformer major overhaul is widely applied in Finland. Usually, a major overhaul procedure requires that the unit is moved to the factory where several maintenance actions and diagnostic measures are taken. A major overhaul costs nearly one fourth of the new transformer price so it is necessary to comprehensively evaluate the costs of that maintenance strategy. Also, the effect of condition monitoring is taken into account in the reliability function.

5.3.1 Failure rate surveys

Cigre international survey 1968-1978

The most extensive results were presented by the Cigre working group 12.05 where information was gathered from 13 countries including Finland. This international survey presents failure information from approximately 47 000 unit-years from 1968 to 1978 and 7000 transformer units were reached in the survey year 1978. /51/

Table 5-1 Cigre international survey failure statistics for power transformers with highest rated voltage between 100 – 300 kV. /51/

Age of unit	Number of unit-years	Number of failures	Failure rate (p.u.)
0 - 5	7796	131	0,017
5 - 10	7471	143	0,019
10 - 20	9698	216	0,022

The Cigre Working group concluded that the average transformer failure rate can be stated to be 2 % per year. Failures which involve longer outage times, such as transformer design, manufacturing and materials occur three times more often than the other identified causes, such as incorrect maintenance, abnormal overload, lightning or loss of cooling. /51/

Fortum Service Power Transformer failure statistics

The latest transformer fault rate research in Finland was made in 2005 by Fortum Service. The transformers were used in various locations, from industry to power plants, and for the most part in electricity transmission and distribution. Altogether 413 transformers were taken into account and major overhauls were made to 136 units after an average of 26,6 years operation time. For the most part the data consist of 110 kV transformers with only one were from the 220 kV and 400 kV voltage levels. The most common transformer power size was 31-60 MVA, with 104 units altogether. /87/

Table 5-2 Fortum Service fault statistics survey in Finland for power transformers without and after major overhaul (MOH). Annual fault rates are in p.u. values. /87/

Years in operation	0-5	6-10	11-15	16-20	21-25	26-30	31-35	36-40	41-45
unit-years (without MOH)	1114	1138	1184	1113	985	713	330	187	100
Fault rate without MOH	**0,024**	**0,028**	**0,026**	**0,031**	**0,021**	**0,043**	**0,048**	**0,037**	**0,040**
Fault rate after MOH						**0,0197**	**0,0396**	**0**	**0,008**
unit-years (after MOH)						254	202	168	125

Statistical information is limited in this Finnish power transformer survey and that is visible, for example, in that there were not any faults after major overhaul between operation years 36-40 in the original data. Naturally, the failure rate value 0 is left out from the evaluation and the result sensitivity is analysed. A failure rate difference between transformers with and without major overhaul is 0,021 in average and the 90 percent confidence value for the average difference is ±0,011. Major overhaul decreases the power transformer fault rate by 55 % with a 90 percent confidence interval of ± 20%.

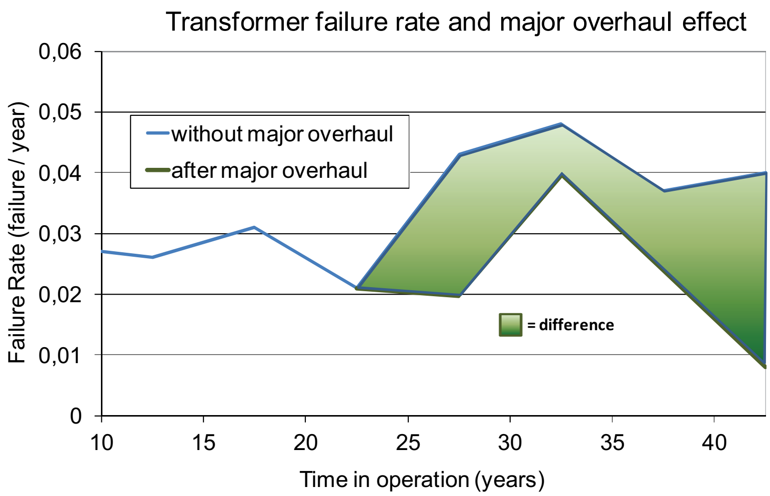


Figure 5-4 Fortum Service's power transformer failure rate data according to time in operation, with and without major overhaul, and also the difference between those failure rates. /87/

Statistical fault rate information ranges up to 45 years in operation, but the information at the end of the time scale is not so reliable, because only a few transformers are used fully after 40 years in operation in this data. Usually aged transformers are for backup and are used just occasionally, so the fault statistics show that the fault rate is decreasing, which is not the case in real life. Although the data is limited the survey gives information for evaluating the benefits of major overhaul to some extent. It is necessary to weigh this information together with the extensive international Cigre transformer survey. /87/

Modelling transformer end of life failure rate is more complex because many factors affect the failure characteristics with a high degree of uncertainty. For example, as mentioned earlier, many DSOs use relatively old transformers as a backup for the normally aged units, which also decrease the chance of failure in the last operational years. Also, special maintenance tasks are performed for the old units such as more frequent condition diagnostics. At the same time, while forty year old units are scrapped some fleet statistics show 60 to 70 years old transformer units still in operation. For example, one of three transformers from the same substation was scrapped when the unit was 40 years old. Usually specialists check the DP-value of the transformer while dismantling the unit. In this specific case the DP-value was 600, which is reasonably good; at least paper degradation did not justify the scrapping.

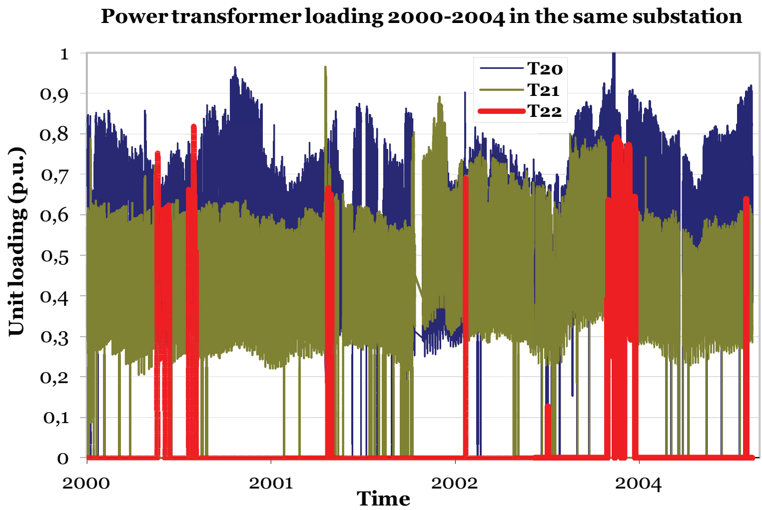


Figure 5-5 A three transformer substation loading between 2000-2004. The red-line represents transformer T22 loading, which was used as a backup and scrapped in 2006.

The figure above shows that during the last operational years transformer T22 was used only occasionally. Altogether the Helen electricity network SCADA statistics point out that the transformer in question was loaded only 9 percent of the time between years 1998-2004. The reason for this transformer's somewhat premature renewal was part of an overall strategic solution where the whole substation was renewed fully. Of course, the DP-value information was not available during the decision-making.

RTE Power Transformer Fleet Failure Data

The French transmission system operator RTE published transformer fleet failure statistics in 2008. The study included 1259 power transformers. Two thirds of the fleet had a high voltage 215 kV winding, 23 percent 400 kV and the rest were 150, 90 and 63 kV transformers. /65/

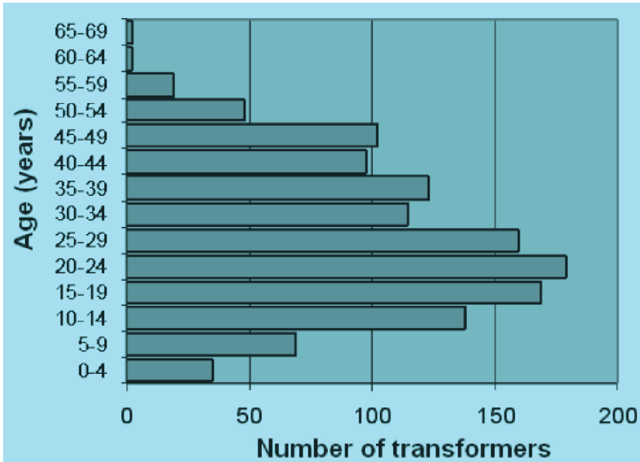


Figure 5-6 **RTE transformer fleet age distribution. /65/**

At the end of the survey period 1994-2004 the fleet average age was 27 years, but still 40 percent of the transformers were older than 30 years. Many transformer types were included in the survey, such as three and single phase autotransformers and single phase transformers, the majority in the data consisting of 920 units were three phase transformers, which is very suitable for this thesis. /65/

The RTE Failure data consist of two components: transformer annual serious failure rate and forced outage rate. A failure was categorised as a serious failure when the outage time lasted longer than eight days. The rate stays around the low level 0,005 in the years between 5-20, but rises to over 0,01 for the units older than 30 years. /65/

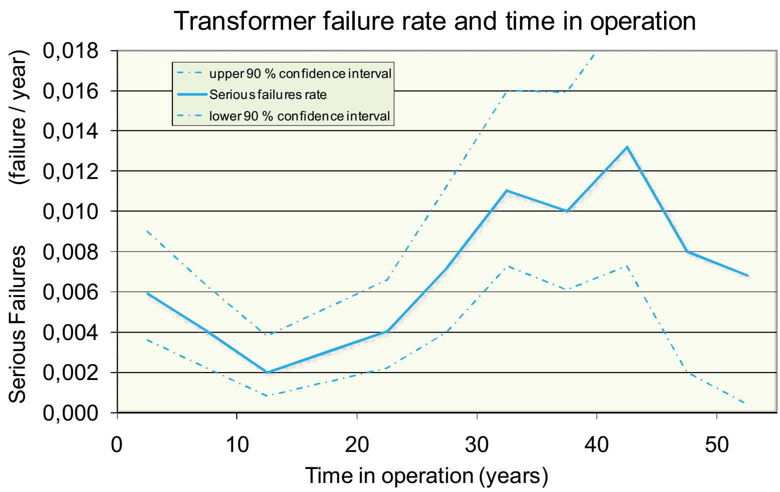


Figure 5-7 RTE transformer fleet's annual rate for serious failures according to age of transformers. The confidence interval (90 percent) is presented with dotted lines /65/

It is noteworthy that the failure rate is relatively high for the first five years, as highly standardised factory and site acceptance tests usually eliminate defective units. Higher failure rates in at least the first ten operational years are not very common according to the Finnish reliability survey. Although Finnish data do not show any significant early stage bath-tube curve failure rate it is still taken in account as an extra security measure. In this thesis, failure rate is considered to be 50 % higher in the first year in operation and 25 % in the second year. /65/

Problems with cooling, control panels and other transformer equipment lead to lighter forced outage 7,5 times more frequently compared to serious failures, while the global serious failure rate was 0,0061 per year, the average forced outage rate was 0,046 annually. On average the serious failure rate is 13 percent of the forced outage rate. The forced outage rate values resemble the serious failure rate in three ways. The outage rate for the first ten years is higher and after a relevantly long drive-in-period decrease to 2 %. The next twenty year's outage rate increases evenly from 2 % to 6 %. It is important to notice that between years 32 to 37, the outage rate decreases approximately 3 percentage unit and RTE specialists reckon that maintenance undertakings may have been the reason for this drop. /65/

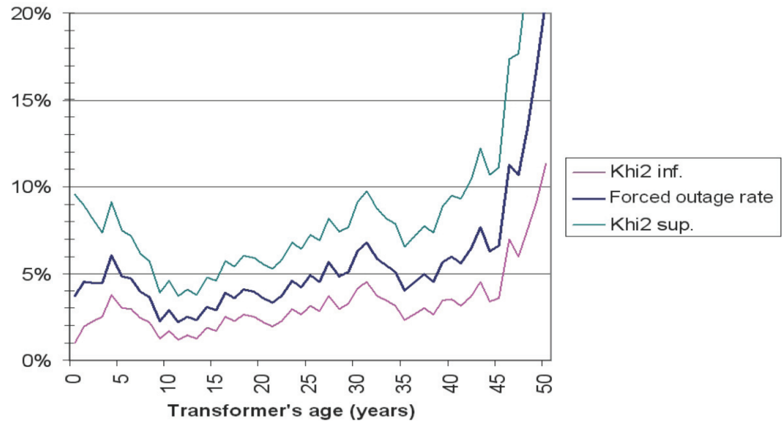


Figure 5-8 **RTE power transformer fleet forced outage rate with 90 percent confidence interval (Khi2 inferior and Khi2 superior). /65/**

After 37 years in operation the outage rate increases of an accelerating rate that value more than doubles within a ten year period to 11 % and to 20 % after 50 years in operation. During the survey period RTE did not apply a general refurbishment policy to extend the transformer life-time like in Finland, where a major overhaul policy is common practice. In the RTE publication in question, The French TSO considered a new refurbishment policy criterion for power transformer life extension, but it remained a lighter overhaul process than in Finland. The units are not moved to the factory, but are refurbished on the site. /65/

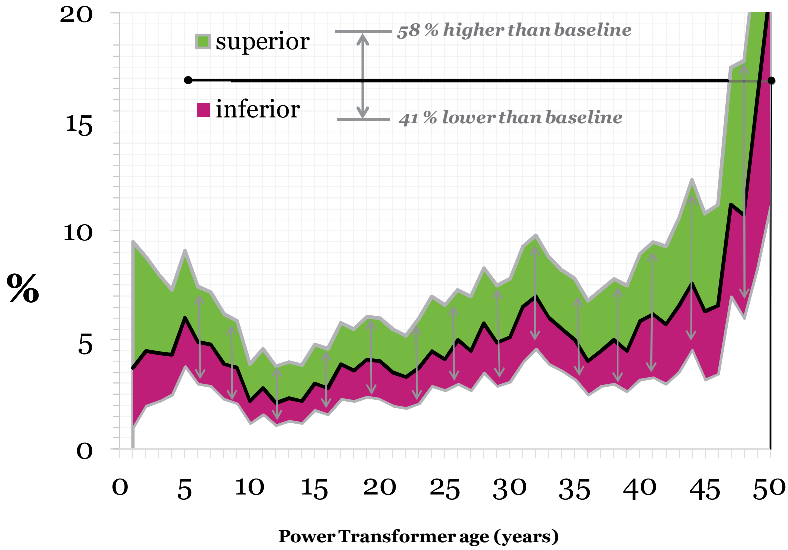


Figure 5-9 **RTE's power transformer fleet forced outage rate baseline and 90 % confidential intervals for superior and inferior rates. /65/**

According RTE's analysis, there is a 90 percent probability that the actual fault rate is in the area described in the previous figure. The confidence interval's superior fault rate is 58 % higher and inferior rate is 41 % lower than the baseline on average. The use of the confidence interval superior and inferior fault rate difference is only indicative in dynamic scenario modelling, because the entire numerical RTE research data was not available from this research, only the summary results presented by Blanc et al. /65/ Approximating the upper and lower fault rate intervals for combined data it is safer to use 60 % for the superior level and 40 % for the inferior level. So with these limits, regarding the fault rate sensitivity, there is a 100% change interval.

5.3.2 Failure rate data

The Cigre and Fortum Service statistics are weighted with transformer unit-years to give a for joint failure rate for the first 20 years. Altogether Cigre and Fortum Service data for the first 20 years comprised of 29 514 transformer unit-years. The 20 to 40 year failure rate data is from the Fortum Service survey for transformers without major overhaul, which comprises 2215 transformer unit-years from that period. RTE statistics provide information to the last years in use, where the outage rate rises from 0,04 to 0,2 within ten years, between 40 – 50. A conclusion from the transformer failure rate surveys is presented in the following table.

Table 5-3 Data for the power transformer failure rate according to the age of the unit.

Years in operation	0-5	6-10	11-15	16-20	21-25	26-30	31-35	36-40	41-45	47,5	50	64
Failure rate (p.u.)	0,018	0,02	0,02	0,024	0,021	0,043	0,048	0,04	0,06	0,11	0,2	1

The last value is a measure of precaution due to the lack of statistical information and it claims that a transformer will fail with 100 % certainty after 64 years in operation. Even the RTE fleet age distribution shows that some older units are still in operation and international examples of insulation paper degradation also show that a transformer can operate after 64 years, but still it is reasonable to stay on the safer side when there is not enough relevant data to prove otherwise. Also, there is no relevant information about the reliability of very old transformers yet, but many transformer asset owners especially in western countries, are focusing on managing ageing infrastructure. For the future it is relevant to follow the newest information from transformer asset management research and update the data continuously.

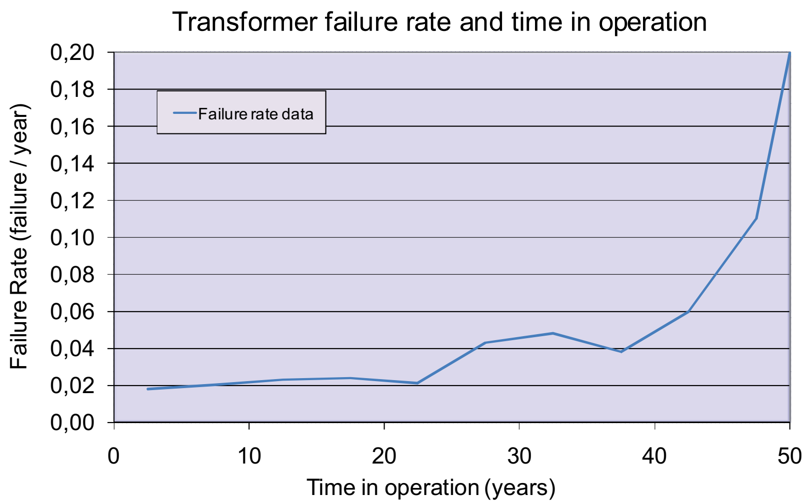


Figure 5-10 Power transformer failure rate data base line without major overhaul. /87/ /51/ /65/

Now the base line for transformer failure rate without major overhaul is comprised of three surveys, which include 40 000 unit-years of data. The next step is to model a function from the information. /87/ /51/ /65/

5.3.3 Failure rate function

The first version of the exponential fault rate function is developed from of the statistical information presented in the previous chapter. An empirical way to model a relative failure rate function for ageing is to use exponential functions to approximate the statistical information. /47/

Exponential fault rate function:

$$\lambda(\mathrm{t}) = a \cdot e^{bt} + c \tag{5.1}$$

Where a,b are age-dependent constants and c is the age-independent part of the failure rate function. /47/

A transformed regression model is used to generate the exponential failure rate function. Although the transformed regression model includes discrepancy due to linear transformation, it is irrelevant in this case. The function suitability with the data can be checked from the next figure. The transformed regression model gives the following values with a correlation coefficient R^2=0,9332:

a = 0,001 **b = 0,0994** **c = 0,0169**

So the baseline function for power transformer failure rate is:

$$\lambda(\mathrm{t}) = 0{,}001 \cdot e^{0{,}0994t} + 0{,}0169 \tag{5.2}$$

Naturally, a failure rate function has a degree of uncertainty and it is necessary to use a sensitivity analysis for the function. RTE's 100 percent interval rule of thumb is used here, although with the combined fault rate statistics it is not exact. Nevertheless, the accuracy is sufficient for the sensitivity analysis. The superior rate is 60 % higher and inferior rate is 40 % lower than the base rate. In this case, the baseline failure rate function sensitivity effect in scenarios is evaluated with 100 % value difference in the following way:

$$\lambda_{\text{inferior}}(t) = \lambda_{base}(t) \times 0{,}60 \tag{5.3}$$

$$\lambda_{\text{superior}}(t) = \lambda_{base}(t) \times 1{,}60 \tag{5.4}$$

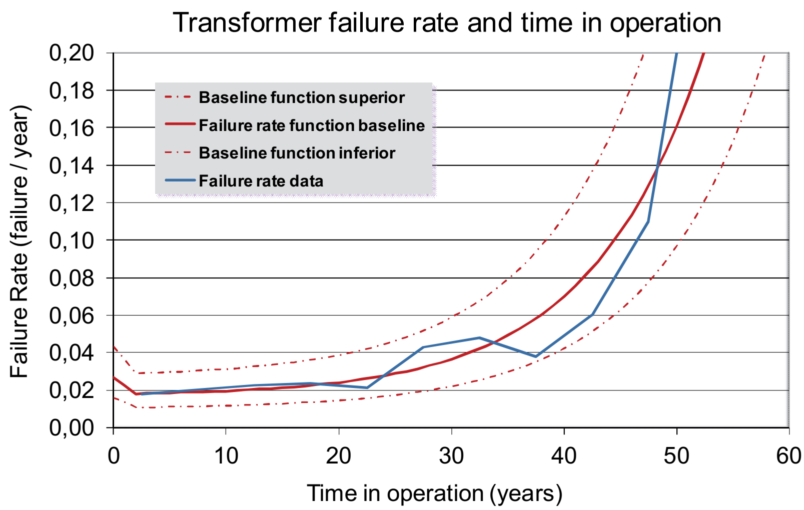


Figure 5-11 Baseline failure rate data used to form exponential function, with inferior and superior boundaries for the sensitivity analysis. The function is formed with a transformed regression model. /87/ /51/ /65/

Classical failure rate bathtub curves have three parts: early burn-in period with decreasing failures, constant random failures in the useful period and increasing failures in the wear-out period. A strong history of standardised factory and site testing procedures has lowered significantly the transformer burn-in period failures. A clear burn-in period high failure rate is not visible in the Cigre and Fortum statistics, because possible burn-in period failures are usually caught in the factory and site acceptance tests. The RTE statistics, however, show clear burn-in period phenomena, with a higher failure rate compared to the normal useful period. /64/

As mentioned earlier, the burn-in period is modelled for the first two years in operation, with 50% and 25 % higher failure rates compared to the exponential function.

$$\lambda_{\text{Burn-in-year-1}}(0) = \lambda(0) \times 1{,}50 \tag{5.5}$$

$$\lambda_{\text{Burn-in-year-2}}(1) = \lambda(1) \times 1{,}25 \tag{5.6}$$

The whole baseline function with the burn-in period:

$$\lambda_{base}(\mathrm{t}) = \begin{cases} \lambda(\mathrm{t}) \times \left(1{,}50 - \frac{1}{4}t\right) & 0 \le t \le 2 \\ \lambda(\mathrm{t}) & \mathrm{t} > 2 \end{cases} \tag{5.7}$$

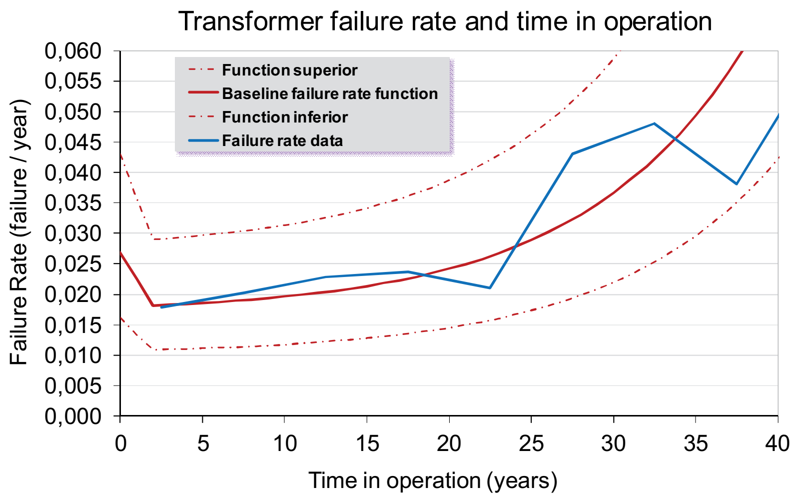


Figure 5-12 **Power transformer failure rate baseline with two year burn-in period.**

Now the baseline function for transformer failure rate has been formed from the data. The next step is to evaluate the effect of different maintenance strategies on power transformer reliability.

5.3.4 Major overhaul effect

Power transformer major overhaul is a significant maintenance operation and it costs a lot of money compared to the full capital investment of the unit. It is reasonable to put effort into analysing the possible effects that this operation has overall. Fortum service has conducted research in Finland about this topic, although the scientific output from this study is statistically narrow because there were only 413 transformer units included. But it is still the most extensive study on that subject in Finland. Globally, there is also a lot to develop in the statistical analyses of different transformer maintenance strategies. In many cases the network asset manager is uncertain whether to do major overhaul or not, due to the lack of information for the decision-making. This attempt is to increase the knowledge about the relevance and sensitivity of that relevance regarding whether to apply major overhaul in the DSO maintenance actions portfolio. Basically, the major overhaul utility function depends on:

- Maintenance effects on the fault rates,
- Place where the transformer is located in the network,
- Price development of optional total renewal,
- Reliability requirements from the customers that the transformer serves,
- Unit's operational history
- Finally, expert judgement in all

This is quite a demanding list to evaluate at the same time and the analysis is not comprehensive if some crucial information is left out, for example overall reliability expenses or the price development of the new units. Again we are dealing with attributes that include uncertainty and that is the reason for the scenario assessment, to see how this complex entity behaves in the different circumstances. The major overhaul reliability effect is modelled on the basis of Fortum Service reliability data.

Major overhaul effect to failure rate function

This approach examines major overhaul failure rate effect as a relative share decrease that acts as an ageing dependent constant. Fortum service statistics are quite concise in information quantity and so the constant share approach is much safer when used with a sensitivity analysis, to see how close alternative conclusions are about the overall benefits. The calculation from the Fortum Service survey results indicates that the major overhaul effect on the failure rate is a 55 percent decrease ±20% with a 90 percent confidence interval. The fault rate major overhaul factor f_{MOH} = 0,45±0,2 is comprised from 1724 transformer unit-years of data, from operational years 26 to 35 and from 41 to 45. Because the amount of data is relatively small, the base major overhaul factor is chosen conservatively; f_{MOH} = 0,45+0,2 = 0,65, so major overhaul decreases annual power transformer fault rate by 35 %.

The major overhaul effect to power transformer fault rate:

$$\lambda_{MOH}(t) = \begin{cases} \lambda_{base}(t) & 0 \le t < \left(T_{MOH} + 1\right) \\ \lambda_{base}(t) f_{MOH} & t \ge \left(T_{MOH} + 1\right) \end{cases} \tag{5.8}$$

Where,

$\lambda_{MOH}(t)$	**Power transformer fault rate function with major overhaul**
$\lambda_{base}(t)$	**Power transformer fault rate baseline function**
f_{MOH}	**Major overhaul fault rate factor**
T_{MOH}	**Major overhaul year**

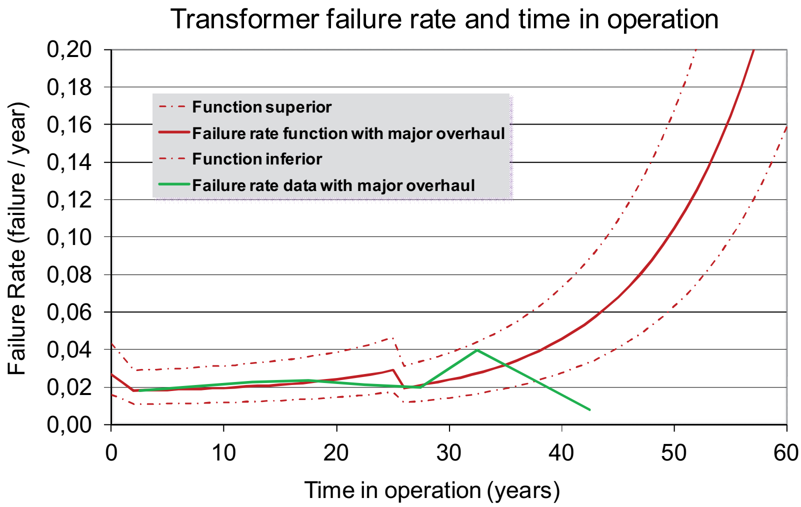


Figure 5-13 Power transformer failure rate data with major overhaul and failure rate function with major overhaul factor equation x using constant factor f_{MOH} = 0,65.

The Percent major overhaul factor aligns overhaul ageing-dependent effects to the failure rate function. For example, transformer insulation paper and oil contain some levels of water and this moisture accelerates the operative ageing of the transformer. During a major overhaul, the transformer insulation paper and oil are dried and this operation decreases the speed of the transformer's relative ageing process. Joints inside the transformer can loosen due to thermal movement and the loosening of the joints can accelerate the thermal effect, which again accelerates the whole ageing process. Loose joints are tightened in a major overhaul. For these reasons it is reasonable to conclude that a major overhaul has an effect on the ageing-dependent parts of the failure rate function, which in turn justifies the use of a major overhaul factor.

5.3.5 Maintenance and Condition Monitoring Effect

Reliability can be improved with maintenance and condition monitoring in our experiences in Helsinki Energy. Time based maintenance has been the maintenance backbone in the power transformer maintenance strategy. Condition based maintenance actions have increased and the concept of reliability centered maintenance strategies in power system asset management has become familiar. Typically, transformer loading and temperatures are monitored and, in special cases an online gas analyser is used to monitor the most critical units. Overload, overheating, cooling system failure indicator and oil level alarm are implemented on every unit. Condition monitoring and maintenance has frequently prevented interruptions in the electricity distribution system in Helsinki.

Figure 5-14 Power transformer incipient fault detected with off-line diagnostics in 2003.

In the example figure above, a portable gas analyser detected a deviating gas development trend in a power transformer, which signalled local overheating on the basis of the gas composition. The reason was partial discharges in the aluminium-copper joint, which would have eventually led to failure and interruption in the electricity distribution, this was prevented and fixed due to the critical information gained beforehand. Uncertainty factors increase when there are no measurement results and monitoring in the transformer: life-time prediction is much more inexact and in such cases the: probability density function is widely distributed. Life-time prediction can be more accurate with the information received from condition monitoring: the probability density function is narrower with monitoring and gives the possibility to use components more efficiently. /94/

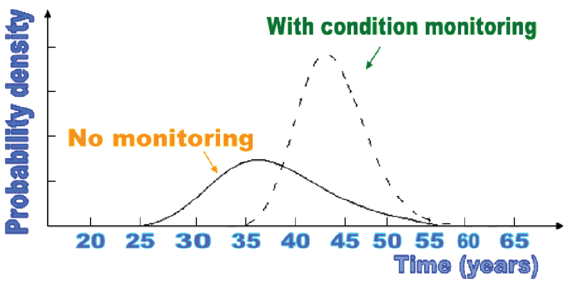


Figure 5-15 The idea of the predictive probability density function for transformer lifetime: maintenance strategy with both major overhaul and condition monitoring (dotted line), and with neither. /93 applied/

Major overhauls and concrete maintenance actions can move the operational lifetime probability density centre to the right, as shown in the figure above. Frequent maintenance actions give more accurate lifecycle information and so the probability density function shape gets narrower the more actual and real-time information is used in asset management. Of course, there are many other factors besides maintenance that affect the shape of the probability density function, such as differences in the manufacturing processes and operational history.

This analysis applies condition monitoring detection rates presented in The Cigre example calculation on “Guide on Economics of transformer Management” /59/. The guide suggests when it is possible to use local expert analysis in the use of detection rate values, because data acquisition covering the effect of the condition monitoring effects been gathered over a relatively short period of time and the statistical reliability is not yet high. However, there is no better local information available, merely some cases that show the practical benefits of condition monitoring, but not with statistical significance. Cigre example values are used with the sensitivity analysis. In the Cigre guide transformer **on-line condition monitoring** is presumed to detect **60 %** of incipient faults that have not been detected with offline diagnostics. The offline diagnostics detection rate was **30 %** in the example. This example uses the offline detection rate as a base detection rate for units with a normal **time based maintenance** program and simple temperature measurement monitoring and basic protection relays. /59/

Condition based maintenance has increased along with the concept of reliability centered maintenance, which in this case means extra and more frequent monitoring in the situations where the transformer network position is more critical or characteristic condition information gives reason for extra actions. In 2008 condition based analyses were made on chosen units on the basis of criticality and a suitable representation of the whole power transformer fleet. One essential incipient fault was detected and fixed related to the connection for the tap changer. The economic benefit of condition related extra maintenance actions are evaluated with an estimate that is a little lower than for time-based maintenance. This analysis uses a **20 %** detection rate value for the extra **condition based maintenance** actions practiced in Helen Electricity Network. A failure probability tree is built on the previous information to model the effects of different maintenance condition monitoring levels.

Base incipient fault detection rates in the analysis and event tree:

Time Based Maintenance	$\delta_{TBM} = 30\%$
Condition Based Maintenance	$\delta_{CBM} = 20\%$
On-line Diagnostics	$\delta_{OLD} = 60\%$

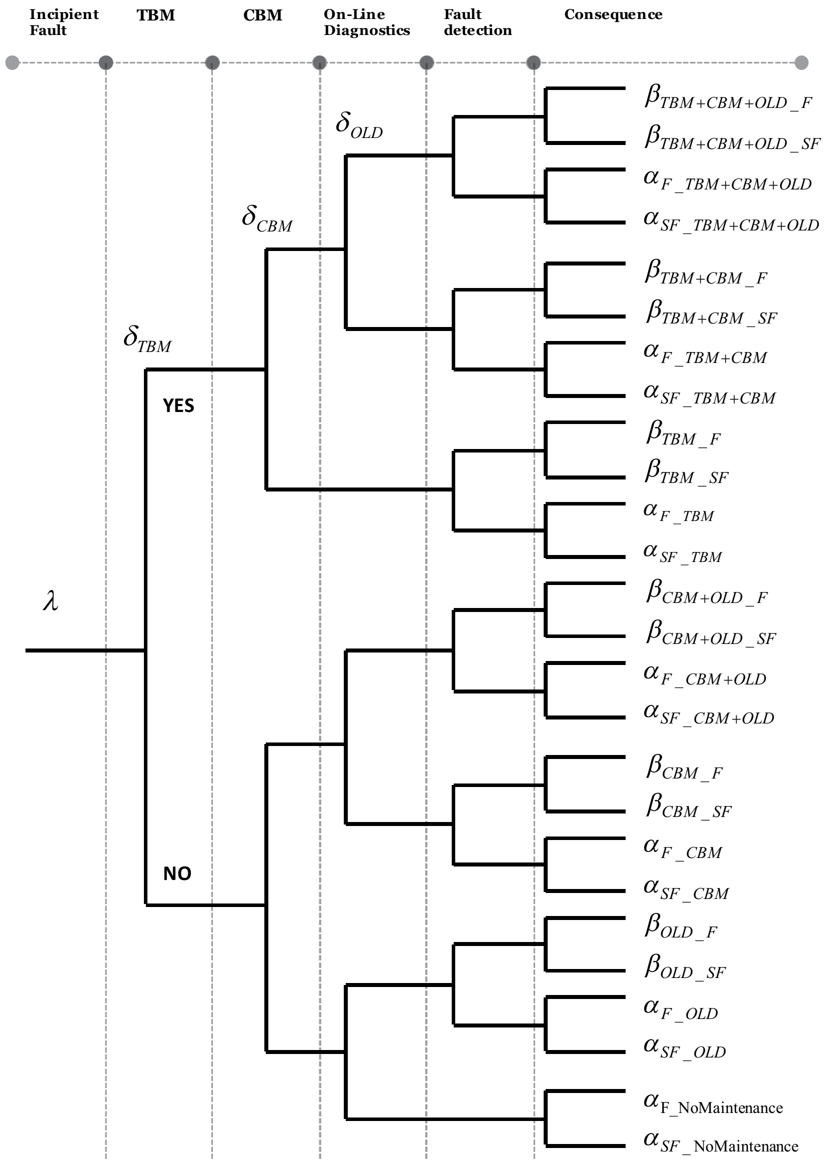


Figure 5-16 Event tree and fault rate factors for power transformer failures with different maintenance levels. Alpha fault rate factors denote the share of failures, which lead to interruptions and beta factors denoting the share of preventive maintenance.

The failure probability tree for power transformer faults is modelled with three condition monitoring levels: time based maintenance, condition based maintenance and on-line diagnostics. As presented in the RTE failure statistics the overall faults divide into forced outages and serious failures, as presented in the lower part of the failure probability tree with two alpha-factors: all incipient faults lead to failures when there is not any type of condition monitoring to detect them. Some share of the incipient faults is detected before actual forced outage with time based maintenance and so preventive maintenance can lower the actual failures. The main reason for using the failure probability tree here is to evaluate the division between actual failures and detected faults that are prevented with maintenance.

Equations for the preventive action and failure rates in the probability tree: (5-9)

$$\beta_{TBM+CBM+OLD\_F} = (1-\varsigma_{SF})[\delta_{TBM} + \delta_{CBM}(1-\delta_{TBM}) + (1-\delta_{TBM})(1-\delta_{CBM})\delta_{OLD}]$$
$$\beta_{TBM+CBM+OLD\_SF} = \varsigma_{SF}[\delta_{TBM} + \delta_{CBM}(1-\delta_{TBM}) + (1-\delta_{TBM})(1-\delta_{CBM})\delta_{OLD}]$$
$$\alpha_{F\_TBM+CBM+OLD} = (1-\delta_{TBM})(1-\delta_{CBM})(1-\delta_{OLD})(1-\varsigma_{SF})$$
$$\alpha_{SF\_TBM+CBM+OLD} = (1-\delta_{TBM})(1-\delta_{CBM})(1-\delta_{OLD})\varsigma_{SF}$$

$$\beta_{TBM+CBM\_F} = (\delta_{TBM} + \delta_{CBM} - \delta_{TBM}\delta_{CBM})(1-\varsigma_{SF})$$
$$\beta_{TBM+CBM\_SF} = (\delta_{TBM} + \delta_{CBM} - \delta_{TBM}\delta_{CBM})\varsigma_{SF}$$
$$\alpha_{F\_TBM+CBM} = (1-\delta_{TBM})(1-\delta_{CBM})(1-\varsigma_{SF})$$
$$\alpha_{SF\_TBM+CBM} = (1-\delta_{TBM})(1-\delta_{CBM})\varsigma_{SF}$$

$$\beta_{CBM+OLD\_F} = (\delta_{CBM} + \delta_{OLD} - \delta_{CBM}\delta_{OLD})(1-\varsigma_{SF})$$
$$\beta_{CBM+OLD\_SF} = (\delta_{CBM} + \delta_{OLD} - \delta_{CBM}\delta_{OLD})\varsigma_{SF}$$
$$\alpha_{F\_CBM+OLD} = (1-\delta_{CBM})(1-\delta_{OLD})(1-\varsigma_{SF})$$
$$\alpha_{SF\_CBM+OLD} = (1-\delta_{CBM})(1-\delta_{OLD})\varsigma_{SF}$$

$$\beta_{CBM\_F} = \delta_{CBM}(1-\varsigma_{SF}) \qquad \beta_{OLD\_F} = \delta_{OLD}(1-\varsigma_{SF})$$
$$\beta_{CBM\_SF} = \delta_{CBM}\varsigma_{SF} \qquad \beta_{OLD\_SF} = \delta_{OLD}\varsigma_{SF}$$
$$\alpha_{F\_CBM} = (1-\delta_{CBM})(1-\varsigma_{SF}) \qquad \alpha_{F\_OLD} = (1-\delta_{OLD})(1-\varsigma_{SF})$$
$$\alpha_{SF\_CBM} = (1-\delta_{CBM})\varsigma_{SF} \qquad \alpha_{SF\_OLD} = (1-\delta_{OLD})\varsigma_{SF}$$

$$\beta_{TBM\_F} = \delta_{TBM}(1-\varsigma_{SF}) \qquad \beta_{TBM+OLD\_F} = (\delta_{TBM} + \delta_{OLD} - \delta_{TBM}\delta_{OLD})(1-\varsigma_{SF})$$
$$\beta_{TBM\_SF} = \delta_{TBM}\varsigma_{SF} \qquad \beta_{TBM+OLD\_SF} = (\delta_{TBM} + \delta_{OLD} - \delta_{TBM}\delta_{OLD})\varsigma_{SF}$$
$$\alpha_{F\_TBM} = (1-\delta_{TBM})(1-\varsigma_{SF}) \qquad \alpha_{F\_TBM+OLD} = (1-\delta_{TBM})(1-\delta_{OLD})(1-\varsigma_{SF})$$
$$\alpha_{SF\_TBM} = (1-\delta_{TBM})\varsigma_{SF} \qquad \alpha_{SF\_TBM+OLD} = (1-\delta_{TBM})(1-\delta_{OLD})\varsigma_{SF}$$

$$\alpha_{F\_\mathrm{NoMaintenance}} = (1-\varsigma_{SF})$$
$$\alpha_{SF\_\mathrm{NoMaintenance}} = \varsigma_{SF}$$

Where,

β_{x_F}	**Share of the preventive maintenance for minor faults with maintenance program** x
β_{x_SF}	**Share of the preventive maintenance for serious faults with maintenance program** x
α_{F_x}	**Share of the forced outage failures with maintenance program** x
α_{SF_x}	**Share of the serious failures with maintenance program** x
δ_{TBM}	**Fault detection rate in time based maintenance program**
δ_{CBM}	**Fault detection rate in condition based maintenance program**
δ_{OLD}	**Fault detection rate with on-line diagnostics**
ς_{SF}	**Share of the serious failures from all failures**
TBM	**Time based maintenance program implemented**
CBM	**Condition based maintenance program implemented**
OLD	**On-line diagnostics installed and applied**

Failure rates and preventive maintenance rates can be assessed for the different maintenance strategies with the above equations. The more intensively a power transformer is maintained, the larger the share of incipient faults detected and fixed with preventive maintenance actions. Damages and corrective maintenance costs are naturally lower when a fault is detected and fixed before an actual failure. Preventive maintenance actions are divided into two groups according to whether the incipient fault requires extensive maintenance or just simpler maintenance. Extensive preventive maintenance and simpler preventive maintenance follow the rate between normal and serious failures.

5.3.6 Reliability conclusions

The reliability evaluation in this thesis is based on a combination of international and local Finnish failure statistics. Different maintenance strategies as well as operational history have an effect on failure probabilities. When an incipient fault is detected before a real failure it is easier to repair. In this evaluation an incipient fault has four consequences: failure, serious failure, prevented failure with maintenance and prevented serious failure with timely maintenance.

The failure and preventive maintenance rate equations for a power transformer are:

Failure rate $$\lambda_{PT_F}(\mathrm{t}) = \lambda_{base}(\mathrm{t}) f_{MOH}(t_{MOH})\alpha_{F\_x} \tag{5.10}$$

Serious failure rate $$\lambda_{PT_{SF}}(\mathrm{t}) = \lambda_{base}(\mathrm{t}) f_{MOH}(t_{MOH})\alpha_{SF\_x} \tag{5.11}$$

Prevented failures $$\rho_F(\mathrm{t}) = \lambda_{base}(\mathrm{t}) f_{MOH}(t_{MOH})\beta_{x\_F} \tag{5.12}$$

Prevented serious failures $$\rho_{SF}(\mathrm{t}) = \lambda_{base}(\mathrm{t}) f_{MOH}(t_{MOH})\beta_{x\_SF} \tag{5.13}$$

Reliability as an exponentially distributed probability density function:

Reliability $$R_{PT}(y) = e^{-\lambda(y)} \tag{5.14}$$

Unreliability $$Q_{PT}(y) = 1 - R_{PT}(y) \tag{5.15}$$

Where,

$\lambda_{PT_F}(\mathrm{t})$	**Power transformer failure rate that lead to interruption**
$\lambda_{PT_{SF}}(\mathrm{t})$	**Power transformer serious failure rate that leads to interruption**
$\lambda_{base}(\mathrm{t})$	**Power transformer incipient fault rate base line function**
$\rho_F(\mathrm{t})$	**Prevented failures rate with applied maintenance strategy**
$\rho_{SF}(\mathrm{t})$	**Prevented serious failure rate with applied maintenance strategy**
α_{F_x}	**Share of the forced outage failure with maintenance program** x
α_{SF_x}	**Share of the serious failures with maintenance program** x
β_{x_F}	**Share of the preventive maintenance for minor faults**

β_{x_SF}	**Share of the preventive maintenance for serious faults**
$f_{MOH}(t_{MOH})$	**Fault reduction factor after the major overhaul time** t_{MOH}
$R_{PT}(y)$	**Power transformer reliability in the operation year** y
$Q_{PT}(y)$	**Power transformer unreliability in the operation year** y

5.4 Loading Scenarios for Every Power Transformer

Future investments are highly related to load growth, especially new substation construction. There are various ways to construct a load prediction for a power transformer unit and in this thesis the model is based on planned city zoning, economic development, consumption characteristics and their development into the future. In this manner, a loading prediction is made for every existing and planned power transformer in Helsinki till the year 2030.

A transformer is a long-term investment and transformer losses are significant in the life-cycle costs. Transformer price and losses are related to each other: higher capital costs can reduce losses and vice versa. The lifetime cost for the loss kilowatt is usually calculated when the transformer is about to be purchased with the current or constant energy price. One way to develop the optimisation in this sense is to predict the long-term transformer load curve and loss energy price with different scenarios. The outcome predicts load for every power transformer until the year 2030 in the dynamic scenario assessment model.

a) b)

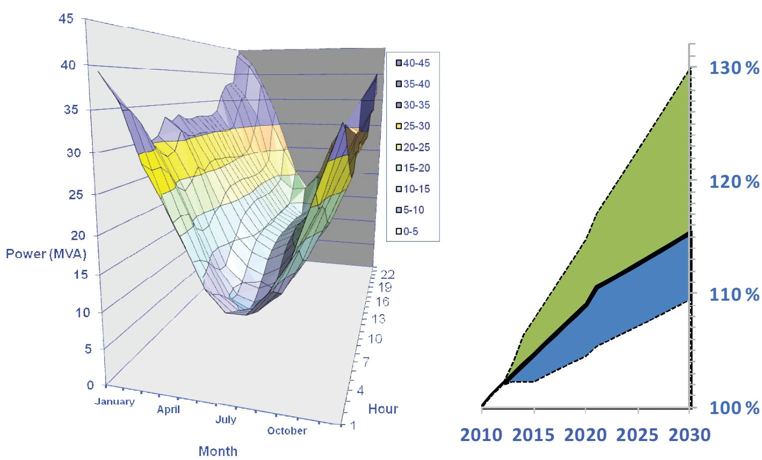


Figure 5-17 **Loading scenario information from Tapanila substation: a) 3D load characteristic figure and b) future peak load development scenarios till the year 2030.**

The year 2010 loading measurements are used as reference curves for every substation loading. This model combines the substation reference curve and peak load prediction together to give the default hourly load for every present and planned substation for the next 17 years.

5.5 Long-term Trend for Transformer Prices

Deepening the analysis of the relations between power transformer capital cost design and losses in different energy and material price scenarios provides new essential information in DSO investment decision-making. Besides a power transformer's essential technical characteristics, there are many choices in the planning table which have an effect throughout the unit's operational life-cycle. Manufacturers make these choices on the basis of the initial values given in the competitive bidding. Choices relate to usage of different materials and design solutions: one example is the choice of transformer core materials such as high permeability steels, and laser-etched steels which define the no-load loss characteristics in operation and initial capital costs. /32/

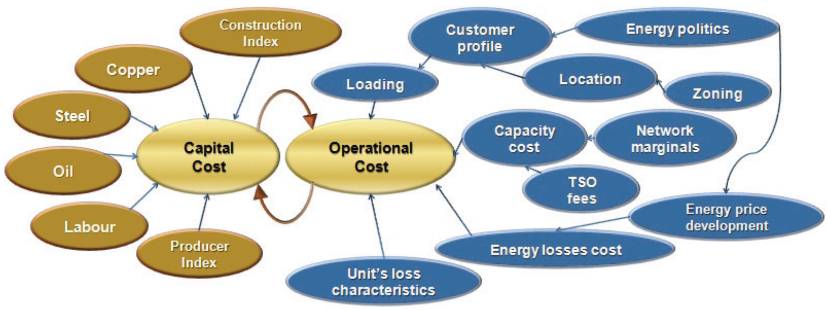


Figure 5-18 General variables when capital and operational cost relation is balanced. Transformer capital cost elements (materials, labour and producer costs) are reflected to future load profile of the unit and development of long-term energy prices.

As mentioned, the classical way to evaluate transformer life-cycle costs during purchase from the DSO point of view is to define a cost assessment for transformer losses. The transformer manufacturer uses customers' capitalised loss expense values as an initial value for designing the balance between capital and operational costs. This thesis integrates long-term power transformer capital and operational costs taking into account future price scenarios of materials, construction, work, energy and future loading development.

5.5.1 Transformer price development

Helen Electricity Network Ltd. has bought 35 power transformer units in the years 1977 to 2009. Between 1975 and 1990 transformer unit prices increased steadily, but after the nineties recession prices decreased approximately 20 percent within ten years until the early 2000s. In 2004 prices started to rapidly grow at a historical speed.

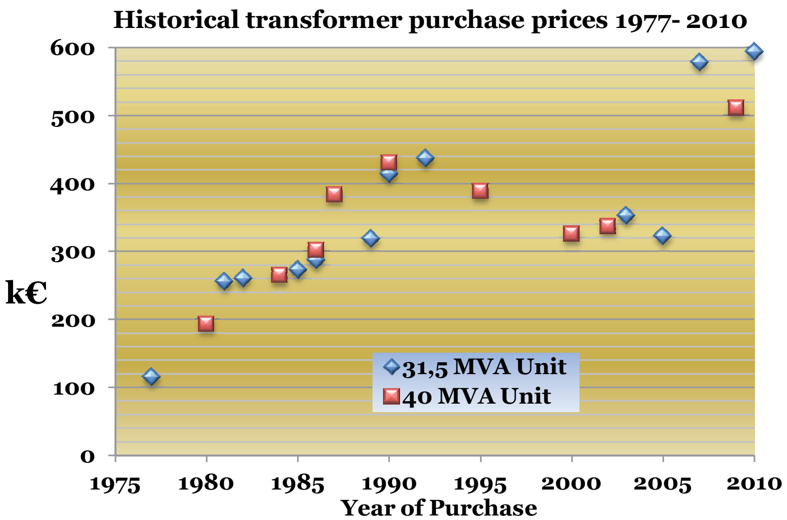


Figure 5-19 **Helen Electricity Network transformer price development between the years 1977 - 2010.**

In the figure above, the power transformer price almost doubled during the three years following 2005. The graph above shows that it is increasingly important to systemically follow the underlying price development factors. One practice is to follow the development of the general construction costs, as is done in construction related businesses. Statistics Finland follows and reports the real price development of construction costs and building works /89/. There are also private companies that are selling professional forecasting scenario services related to future building cost development. The following figure presents power transformer price development and the building index relation from 1985 to 2010.

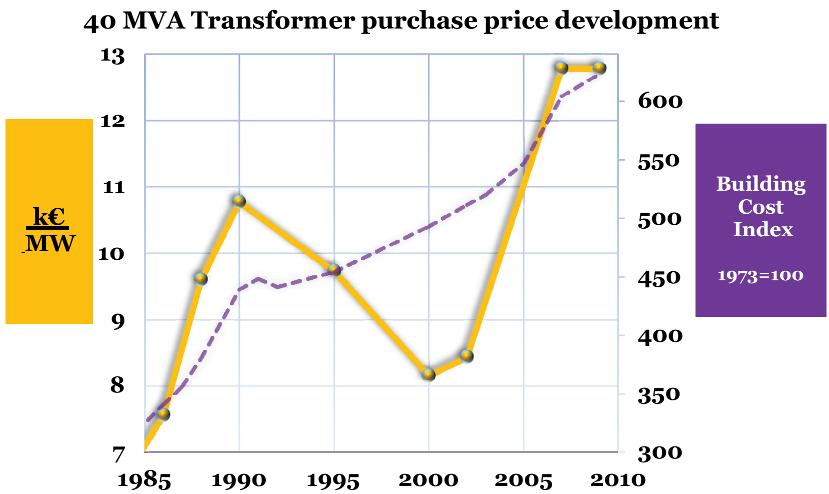


Figure 5-20 **Power transformer unit price (k€/MW) relation to the building cost index development between the years 1985 to 2010. /89/**

The previous figure shows that building cost index development generally reflects to some extent the long-term transformer pricing, but it is not nearly sufficient to reflect the short and medium term price development. The building cost index is an over-dominant index to use in power transformer investment price evaluation.

5.5.2 General Indices and Transformer Price Development

There is the need for a more responsive price development indicator than the building cost index. Power transformer manufacturers normally tie terms of sale to material price indices. There is also relatively large fixed rate representing labour costs and producer indices, which are easier to predict from the manufacturers stand point. The major part of the material costs for a power transformer normally relates to the steel, copper or aluminium and oil. The following figure presents the historical development of these indices.

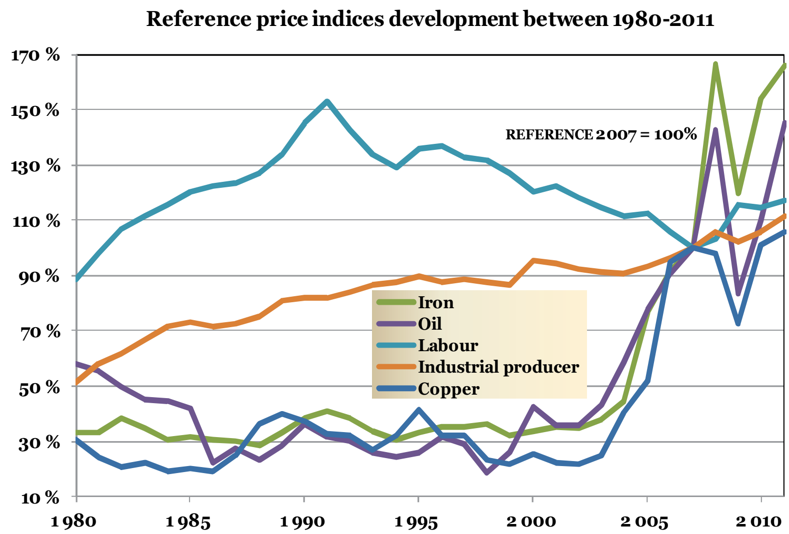


Figure 5-21 Historical price indices development for Iron, Oil, Labour, Industrial Producer and copper costs. These elements are related to power transformer purchase costs. /89/ /90/ /91/ /92/

Material price development has been quite stable in the eighties and nineties compared to the situation during commodities boom in the 2000s. The annual oil price index has almost quadrupled, with a 294 % increase during the years 2002 to 2008. The same increase levels apply to other materials as well. The labour cost in Finland decreased substantially after 1991 during the nineties economic depression and increasing global competition in the labour force. Almost all power transformers were purchased and manufactured in Finland before the 1990.

Power transformer price development is linked to the following indices and shares:

Carbon steel	**25 %**
Copper	**20 %**
Transformer Oil	**10 %**
Labour costs index	**40 %**
Producer Price index	**5 %**

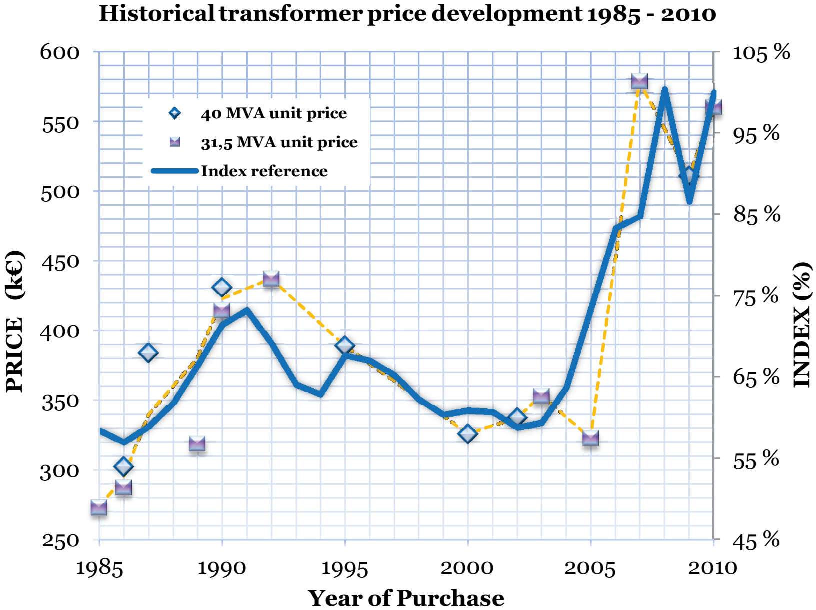


Figure 5-22 Power transformer real purchase prices and reference index development on the basis of the copper, iron, oil, labour and industrial producer indices presented in the previous figure.

The transformer price reference index curve above matches' real power transformer purchase prices very closely, much better than using only the building cost index. Industrial markets were more nation-centric in the last century compared to the current situation, where European Union public procurement legislation has opened trade barriers. It is important to notice that labour costs, which represent the largest share of power transformer costs, should be estimated from the European Union stand point and not the national reference in future scenarios. Transformer price reference index and future material price development scenarios are combined in the dynamic scenario modelling in the sixth chapter.

5.5.3 Loss Characteristics Development

Materials, electrical components and manufacturing processes develop continuously, pursuing ever more efficient use of resources to maximise benefit. Energy efficiency is an important factor in electricity transmission and distribution, especially when energy costs and efficiency requirements are increasing. Power transformer losses present a significant share of the total network losses and transformer energy efficiency has significantly increased from 1955, as The Cigre study for large power transformers shows. /62/

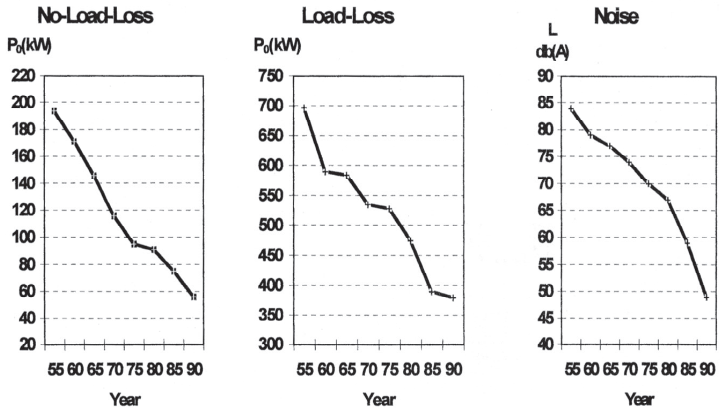


Figure 5-23 Example figures for the characteristic development for large 220 kV power transformers according Cigre studies. /62/

Long-term development has decreased the no-load loss characteristics 3,03 % and load losses 1,5 % per year. For example, core materials and manufacturing techniques have developed from applying a thick soft iron wire to very thin grain-oriented laser-scribed plate core materials. /62/

The sophisticated designing of power transformers means the power losses of new units are considerably lower than before. At the same time, the material and manufacturing costs have increased. The balance between operational and capital costs in the case of transformers concerns the balance between power losses and the amount of manufacturing materials. A simplified view of this matter is that the losses decrease when thicker conductors are used. Of course, this generalisation works only to some extent: there is a limit beyond which the enlargement of the winding construction only increases overall losses. Nevertheless, construction optimisation is left for the manufacturers on the basis of distribution network site specified capitalised loss expenses for load and no-load losses. Nominal transformer losses are measured in the factory acceptance tests which gives the data to calculate loss expenses.

5.6 Criticality Analysis for the Power Transformers

There are different demands related to electrical supply reliability from the customers and so there are significant differences in the criticalities of different power transformer units. Two factors are needed to define risk: the probability of failure and the consequences of failure. A customer criticality analysis for a transformer unit is covering up the latter one. Criticality is a function of substation customer profile and current load, and general load development in the area with the planned network investments. Currently in Helsinki there are 47 power transformers altogether, and nine new units are scheduled along with planned new substations. Research results for customer interruption cost are applied to assess the outage costs for each unit. The next example figure shows the customers profile distribution of one power transformer unit located in the downtown area. Based on the customer profile distribution, real loading data and estimated future loading scenario, the development of the one hour interruption cost for customers is calculated.

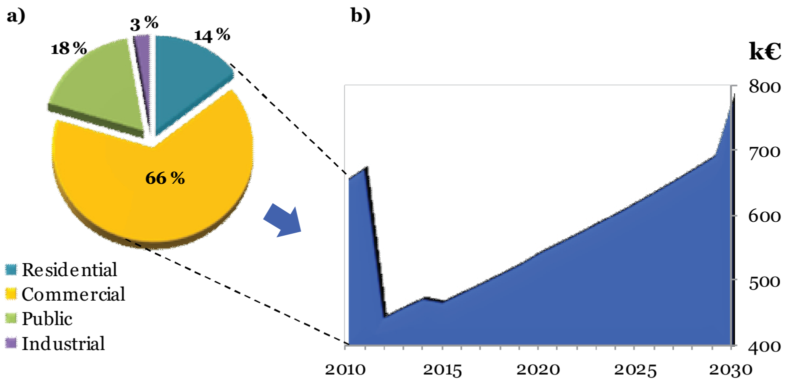


Figure 5-24 a) Customer distribution profile for a single power transformer unit T12 in the downtown area of Helsinki. b) Development of one hour interruption cost for the customers that T12-unit serves using Finnish base values for CIC.

The commercial sector is naturally tied to downtown and commercial consumers' outage cost values almost seven times higher than residential consumers. There is a logical reason for that; as when an interruption occurs in downtowns it may lead to closing large commercial centres during the busy business hours, whereas a residential customer will experience discomfort and indirect costs for the most part. Figure b) presents the development of one hour interruption costs and there is significant drop after 2011, which means that new neighbouring substation and power transformer units are lightening the loading and hence the overall criticality of the unit.

Power transformer loading criticality is calculated with the following formula for every current and coming unit:

$$\mathrm{X}_{PT}(y) = \left(c_r s_r + c_c s_c + c_i s_i + c_a s_a + c_p s_p\right) \frac{i_{cic}(y)}{i_{cic}(y_0)} \overline{p}_{daily_X} \frac{f_{eLoadPT}(y)}{f_{LoadPT}(y_0)}$$

Where, (5.16)

$\mathrm{X}_{PT}(y)$	**Power transformer's loading criticality valuation for one hour interruption in the year** y
c_x	**Cost of one hour interruption for customer type** x
s_x	**Share of the power demand for customer type** x
r, c, i, a, p	**Residential, commercial, industrial, agricultural and public**
$i_{cic}(y)$	**Cost of interruption development index in year** y
$i_{cic}(y_0)$	**Cost of interruption development index in first year**
$\overline{p}_{daily_X}$	**Annual average for daytime peak power for the power transformer**
$f_{eLoadST}(y)$	**Estimated load growth factor for the year** y **in the simulation**
$f_{LoadST}(y_0)$	**Load growth factor for the first simulation year**

The criticality is calculated for every power transformer unit and the following figure presents the criticality development for all current and newly planned units. Naturally, there are differences in the criticality in different unit locations; on the basis of information received from Finnish customers a unit's cost for interruptions can be more than sevenfold. This is valuable information, for example, when considering maintenance strategies and fleet asset management in general.

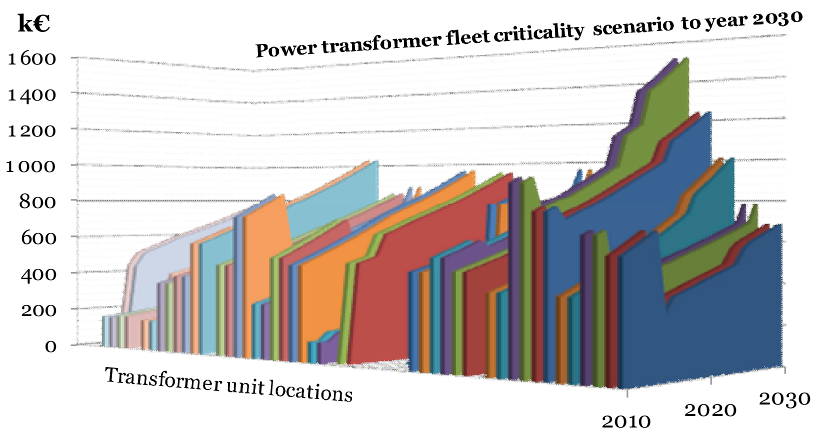


Figure 5-25 Base development scenarios for the consumption criticality which power transformer units serve.

Electricity consumption criticality is related to customers, cost of interruption valuations and consumption development. Consumption criticality measure is not dependent on unit reliability characteristics, because that is defining the other risk factor: meaning the probability of failure whereas criticality is defining consequence. Dynamic consumption criticality is implemented in the scenario modelling.

5.7 Including Expert Judgement

On top of heuristic system modelling there is the need to include expert judgement because the whole system cannot be meticulously modelled in a dynamic way. One clear phenomenon appeared from the historical diagnostic measurements concerning the power transformer fleet reliability modelling and the effect of cooling system adjustments /94/. Mainly, all units are either cooled with OFAF (oil forced air forced) or with ONAF (oil natural air forced) systems. Historically OFAF-cooled transformers have been operated at higher temperatures and therefore the paper insulation degree of polymerisation (DP) has decreased more rapidly compared to ONAF-cooled transformers, with reference to historical loading. A reason for this was systematically too high temperature threshold settings in forced air cooling, hence the cooling ability for an OFAF-system operated in OFAN-mode is too small and the temperature can rise to the threshold level even with very low loading /94/. As a result of the Helen Electricity power transformer fleet analysis the paper insulation DP-value has been decreased to approximately 600 inside OFAF-cooled transformers although the same value for ONAF-cooled transformer is only 900 after 25 years in operation.

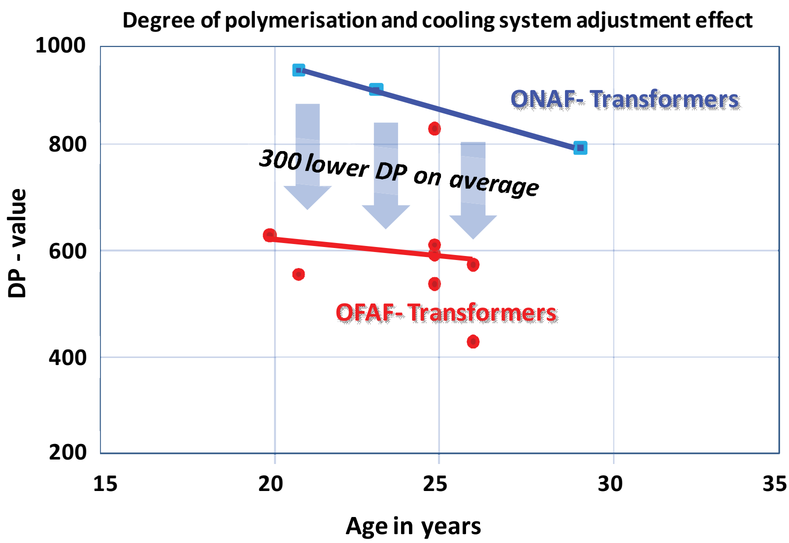


Figure 5-26 Helen Electricity power transformers fleet's paper insulation degree of polymerisation and operational age for eight OFAF and three ONAF cooled units.

The next step is to evaluate the effect of OFAF-cooled power transformer reliability when insulation paper characteristics have decreased faster than expected. In a normal distribution network operation environment, an ONAF- cooled power transformer DP value will decrease approximately 300 units after ten operational years. So this extra OFAF-cooling system 300 DP decrease amounts to a ten normal operational year DP decrease. Also, it is relevant to mention that this OFAF-cooling settings' deficiency was noticed in 2005 and during 2006 all settings were altered in the whole fleet. The period of an OFAF-unit's operation in adverse temperatures is dependent on the year of purchase and the year when the cooling system setting was altered. There are 19 units from the entire power transformer fleet (39 %) that have been affected by the OFAF-defect.

There is the need to adjust the power transformer fault rate function based on the information summarised earlier. In the following case, expert judgment is applied on the basis of available condition information. The OFAF-cooling system setting deficiency effect is derived from the ten normal operational year loss of life within 25 years in higher temperatures. If an OFAF-transformer is used for 25 years with the wrong cooling system setting then the fault rate is calculated by adding ten extra years in the evaluation $\lambda(t_{25}) = \lambda(25+10)$. In this case, the power transformer annual fault rate is 4,9 percent whereas in normal conditions it would be 2,9 percent. Hence the annual fault rate increase $c_{OFAF}(25)$ due to the wrong OFAF-settings is 2,0 percent.

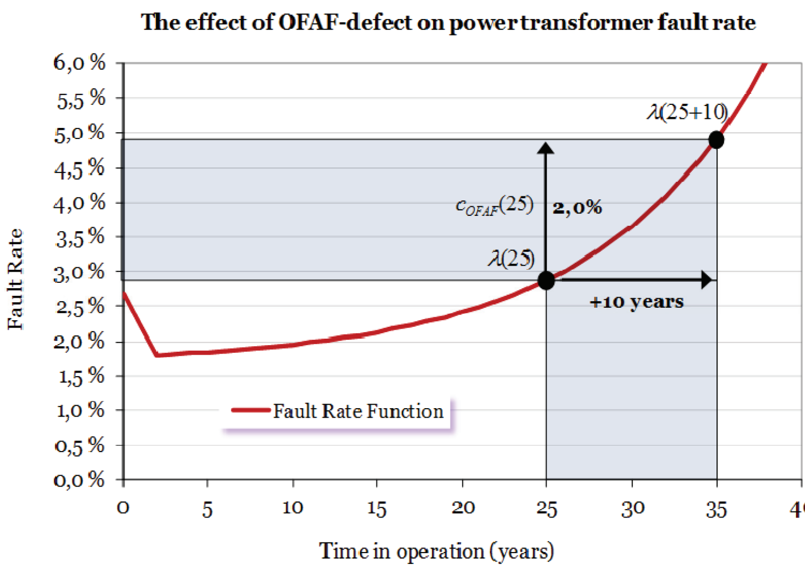


Figure 5-27 Maximum OFAF-cooling system setting defect on power transformer fault rate.

The increased OFAF power transformer ageing effect on fault-rate is calculated with a simple linear function:

$$c_{OFAF}\left(t_{H\_opeOFAF}\right) = \frac{\lambda(35) - \lambda(25)}{25} t_{H\_opeOFAF} = \frac{4{,}9\% - 2{,}9\%}{25} * t_{H\_opeOFAF} \qquad (5.17)$$

Where,

$c_{OFAF}(t_{Operation})$	**Fault rate increase due to the OFAF-defect as a function of time the transformer was operated with the wrong cooling system setting**
$\lambda(t)$	**Power transformer fault rate as a function of time (years)**
$t_{H\_opeOFAF}$	**Time in years when the power transformer was operated with the wrong OFAF-cooling setting**

The oldest OFAF-cooled power transformer in operation is the T18-unit, purchased in 1976, meaning that this specific unit has been operated for 30 years at higher temperature due to the wrong cooling system settings. The entire power transformer fleet has been operated for 355 unit years with the wrong OFAF-cooling setting, which has a significant effect on the power transformer fleet condition and hence on the operational reliability.

6 Dynamic Scenario Assessment: Case Power Transformers

The dynamic scenario modelling is applied to the DSO's power transformer fleet asset management. Specific analyses are made for assessing: investments in a turbulent economic environment, maintenance strategies, overall benefits of online diagnostics and major overhaul actions.

6.1 Power Transformer Scenario Assessment Output

As mentioned earlier, asset management aims to manage asset performance, risks and costs with a strategic target /39/. Although capital investments comprise the largest single cost in the portfolio of asset management transactions, a significant part of the overall asset management costs occurs through the life cycle operations of usage, performance and maintenance. There is therefore the need to evaluate and manage the future cost of the operations as well as the immediate investment costs. The basis for the evaluation is the earlier presented scenarios for economic environmental development and dynamic asset modelling; by combining these can overall asset dynamics can be assessed and managed.

Now it is time to apply the scenario modelling to a distribution Power transformer fleet, to evaluate the overall asset dynamics and then continue with the more specific cases. In order to present an assessment result, the analysis is made on a DSO's power transformer fleet with the detailed asset management plan and with the baseline scenario for economic environment. The example asset management plan, which states the timelines for unit renewal and unit specific maintenance intensity, is presented in Appendix 3.

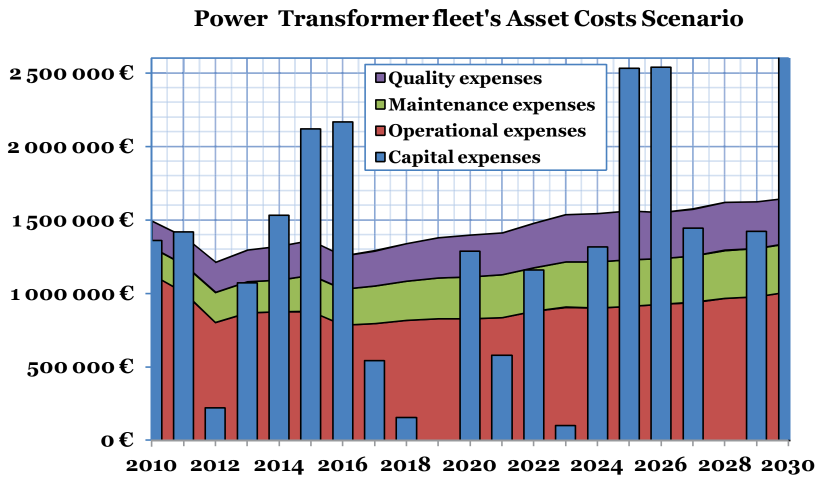


Figure 6-1 DSO power transformer fleet's comprehensive long-term asset cost scenario with economic baseline scenarios described in Appendix 4 and the asset management plan described in the Appendix 3.

Expected net present value[I] for the planned asset management program capital expenses between 2014-2030 is 13,9 million Euros in the base scenario, which comprises 32 new power transformer units, major overhauls and renewals of online diagnostic equipment. The net present value of all other expenditure categories sum to 15,9 million Euros in the base scenarios for the fleet. This specific example shows the scale to which a fleet's operational life-cycle expenses compare to capital investments, even when the time-period in the evaluation is only seventeen years. In the following we look more deeply into what these expenses are comprised of, starting from operational energy losses.

Operational Energy Loss Expenditures

Operative energy losses represent a significant asset cost in the power transformer fleet asset management and with the base scenario the net present value for energy losses is 9,7 million Euros for the next seventeen years 2014-2030. There are significant differences in the operational expenses between power transformer units based on their operational location and the units' technical energy loss characteristics. The economic environment base scenario expects that nominal energy prices will stay at a lower level than at the beginning of the current decade and so, with the DSO's power transformer fleet the energy loss costs remain almost at the same level till the year 2021, with the asset management plan described in Appendix 3. Different energy price and consumption

I Annual expenditures occur in the middle of the year in the evaluation and the net present value is calculated in the middle of the year 2013.

development scenarios give significantly different results and the results are presented later in the text, Chapter 6.1.1.

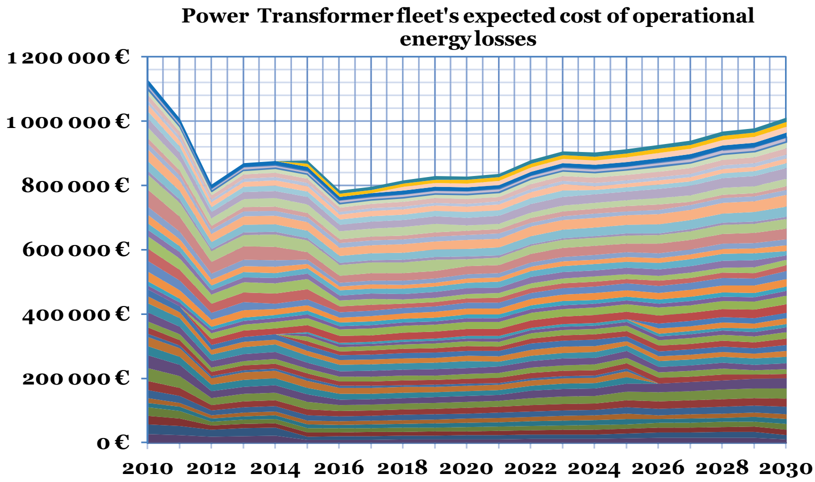


Figure 6-2 Expected DSO power transformer fleet nominal operational cost base scenario development for every unit with the maintenance plan described in Appendix 3.

The Figure 6-2 reveals the operational energy loss expenses for every unit in operation, both currently and planned within the period. The expected load loss expenditures are 54 percent of the overall operational costs in the scenario assessment. Operational loss evaluations are especially important when a power transformer purchase is planned and guideline specifications for the loss capitalisation are defined. These limit values determine the valuation balance between capital and operational expenditures. A secondary need for accurate energy loss evaluation is while optimising the purchase of the DSO's energy losses.

Maintenance Costs

In the assessment, the Distribution System Operator's asset management maintenance program presented in Figure 6-3 is built upon time-based maintenance actions, which are closely tied to the frequent condition assessment and operational age. The maintenance process also requires supportive functions in order to reserve essential spare parts for quick availability: so supporting costs are comprised from all the expenses per unit needed to provide essential spare parts, such as high voltage bushings, within hours. The most critical units and some other units are equipped with Online Diagnostic monitoring, which needs to be maintained as well. After these maintenance processes there are a certain amount of detected incipient faults that are corrected before failure. A maintenance program like this relies on some minor incipient fault preventive maintenance actions and costs. Finally, despite the maintenance process, some incipient faults are not detected and lead to operative failure and so require corrective maintenance. When this happens costs are higher, because of the time pressure and expected wider damage from the failure compared to preventive maintenance actions.

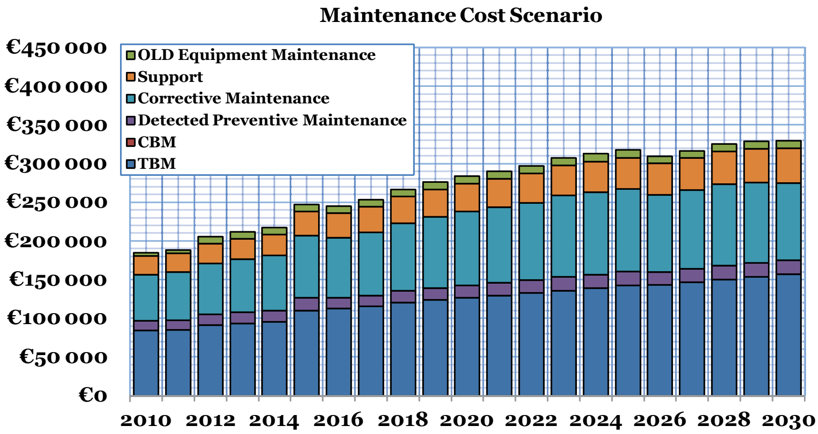


Figure 6-3 Expected DSO's power transformer fleet nominal maintenance cost base scenario for different expenditure categories with the maintenance plan described in Appendix 3.

The overall maintenance costs are 3,1 million Euros in net present value for the time period of 2014 to 2030 in the figure above. One important task for the asset manager in maintenance strategy planning is to find a reasonable balance between preventive and corrective maintenance actions and their associated quality costs. Basically all maintenance actions that are completed before actual failure are preventive maintenance actions. The cost balance between preventive and corrective maintenance is 67 % for preventive costs and 37 % for corrective maintenance costs.

Table 6-1 Expected net present value of the DSO's power transformer fleet maintenance program expense base scenario by maintenance categories, according to Figure 6-3 between 2014-2030.

	Base scenario
OLD Equipment Maintenance	104 472 €
Support	400 074 €
Corrective Maintenance	1 023 301 €
Detected Preventive Maintenance	177 477 €
Condition-Based Maintenance	0 €
Time-Based Maintenance	1 408 592 €
Maintenance Cost Summary	3 113 915 €

Expected Quality costs

Failures that cause interruption into the supply service need corrective maintenance or, if the failure is severe, this may also lead to accelerated renewal investments. Asset management planning and actions determine the fleet quality performance and the following evaluation presents the base level for the expected associated quality cost of the failures that require corrective maintenance.

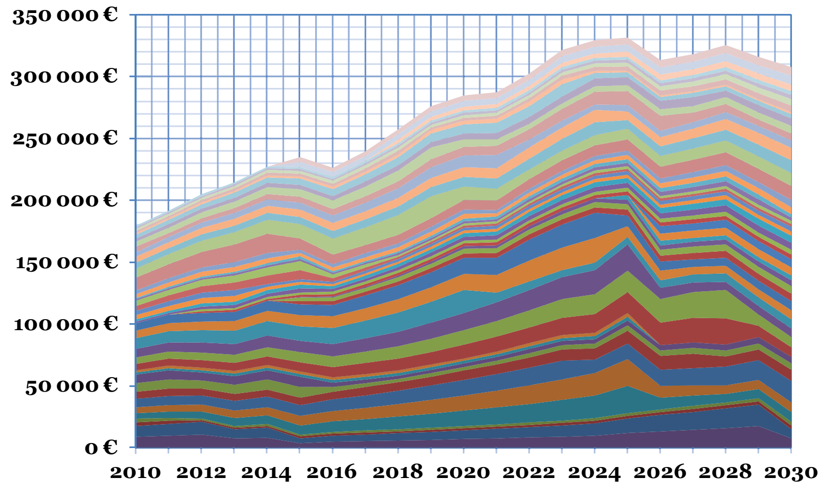


Figure 6-4 Expected quality costs from the customers' point of view for the DSO power transformer fleet with base scenario values and the asset management plan described in Appendix 3.

The expected net present value in the base scenario for the quality costs is 3.1 million Euros for the period 2014-2030. Its noticeable that the expected nominal quality costs in the scenario increase 60 percent within twelve years, between 2012-2024. The reason for that can be found from the asset management for the DSO fleet described in Appendix 3: this asset management plan has excluded condition-based maintenance from the portfolio and so there are no intensified maintenance actions for units at the end-period of their life-cycle. Expected quality costs decrease after 2028 because there are six renewed units and some major overhauls planned around 2029-2030. This particular asset management plan is made to show the basic output of the scenario modelling, which can be assessed for every single unit in the fleet. To make the scenario modelling more dynamic, the asset behaviour must be modelled in different economic environments.

6.1.1 Scenarios and Output Sensitivity Analysis

The previous chapter summarised the scenario modelling output with the base scenario values for the global economic environment and with a specific asset management plan for the whole fleet. Dynamic scenario modelling assesses fleet overall performance for decades to come and so a single base scenario evaluation cannot give a satisfactory output for the decision-analysis. Now different economic scenarios are applied to the

DSO's fleet asset management plan described in Appendix 3, starting with the capital expenses scenario.

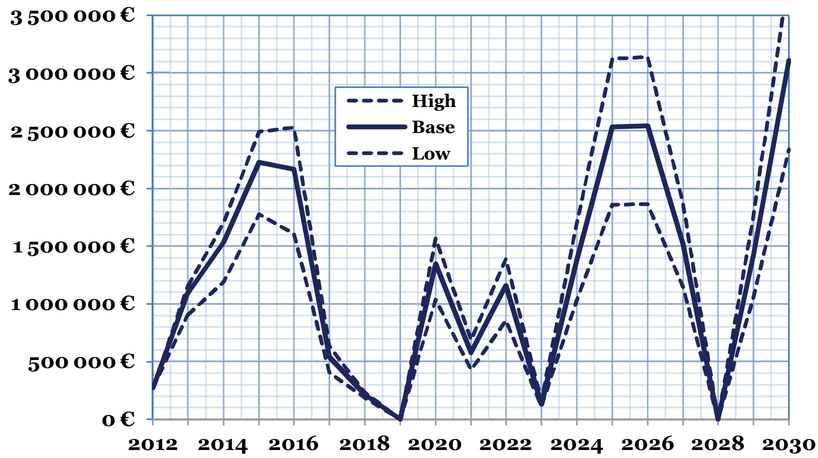


Figure 6-5 DSO's power transformer fleet asset management plan capital costs in different global economic environments. Asset Management plan is described in the Appendix 3.

Global demand for commodities has an effect on power transformer pricing and there can be significant changes within a year. The expected net present value for capital expenses in given circumstances can alter from 10,5 million Euros to 16,6 million Euros, between low and high scenarios for material pricing and labour costs. Capital expenses in the overall valuation of the asset management plan can alter remarkably in a turbulent economic environment, thus changing the balance between capital, operational, maintenance and quality expenses. Therefore, the balance which determines the justified expenditures in asset management for renewals, maintenance actions and operational quality is important, to reflect the different economic environments.

Operational Expenses Scenario

Capitalisation of the power transformer losses in the purchase process is the most relevant point where the balance between operational and capital expenses is determined for the units' life-cycle. The long-term energy price includes many uncertainties and this is visible in the price scenarios for operational energy loss expenses. The cost for loss transfer capacity is also important to take into account and it is paid in two separate ways: in transmission system operator fees and in network capital investments to uphold the network capacity during the operational years. In the base scenario the loss transfer capacity cost median value for a power transformer unit is 15 percent of the overall operational loss expenses and this share varies around ± 5 percent depending on the energy prices and construction cost development. If energy prices are higher, the share of loss capacity cost compared to overall loss expenses is lower, and vice versa.

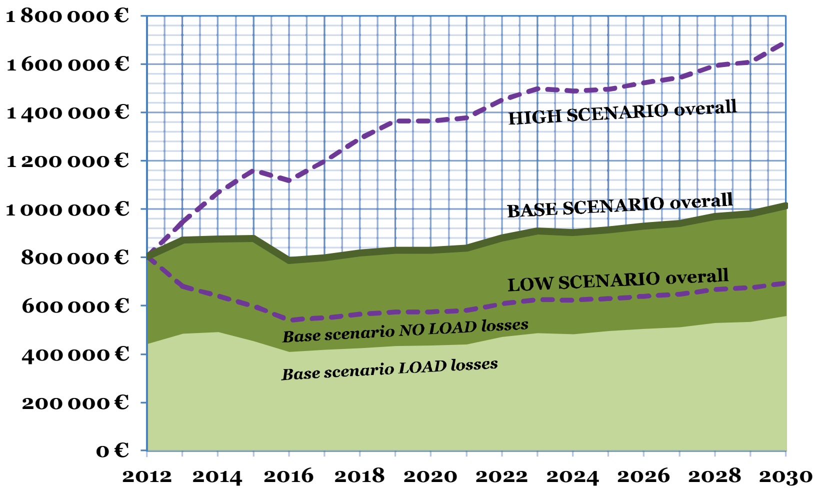


Figure 6-6 Operational cost scenarios for power transformer energy losses in different energy price scenarios. Base scenario costs are divided between load and no-load loss expenses.

The expected net present value for the operational loss expenses in the base scenario is 9,7 million Euros, and it varies significantly in the different energy price scenarios. In the high energy price scenario the expected net present value is 15,0 million Euros, and 6,7 million Euros in the low energy price scenario. In these scenarios the expected NPV for fleet operational losses varies 8,3 million Euros, just based on today's professional assumptions regarding future energy price development. In many practical cases, the evaluation of the operational losses is made with one energy price over the whole unit's life-cycle, but these results point out that it is reasonable to explore the balance with a scenario analysis.

Maintenance and Quality Expense Scenarios

Sensible maintenance strategy is determined in the balance between renewal investments, maintenance and quality expenditures. Maintenance unit expenses vary mainly on the basis of labour costs, and overall costs on the basis of maintenance intensity. The essential thing is to find a reasonable balance between preventive and corrective maintenance actions.

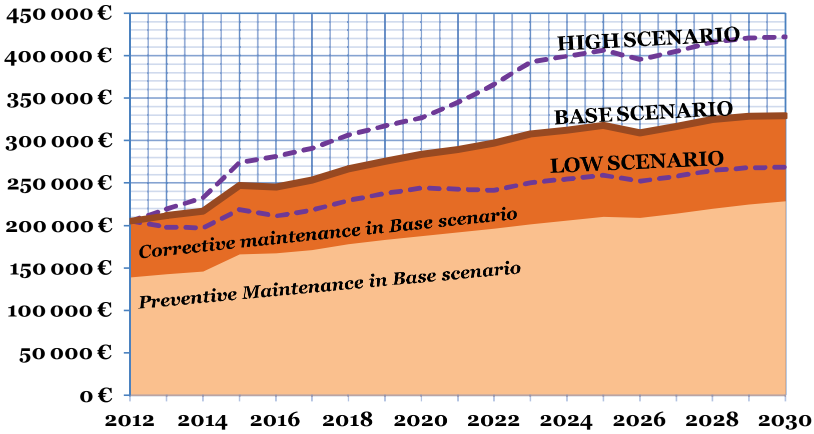


Figure 6-7 Expected overall maintenance expenditure scenarios in different economic environments, where labour costs vary due to changes in global general demand. Base scenario expenditures are divided into corrective and preventive maintenance costs.

The expected net present value of maintenance expenses in the evaluation period and in the base scenario is 3,1 million Euros and 67 percent of overall maintenance costs are comprised of preventive actions. If the higher labour cost scenario is realised then the expected NPV rises to 3,7 million Euros. The lower labour cost scenario the expected NPV is 2,6 million Euros. The applied lower and higher labour unit cost scenarios lead to a -16 % or +20 % difference in the expected NPV when compared to base scenario result.

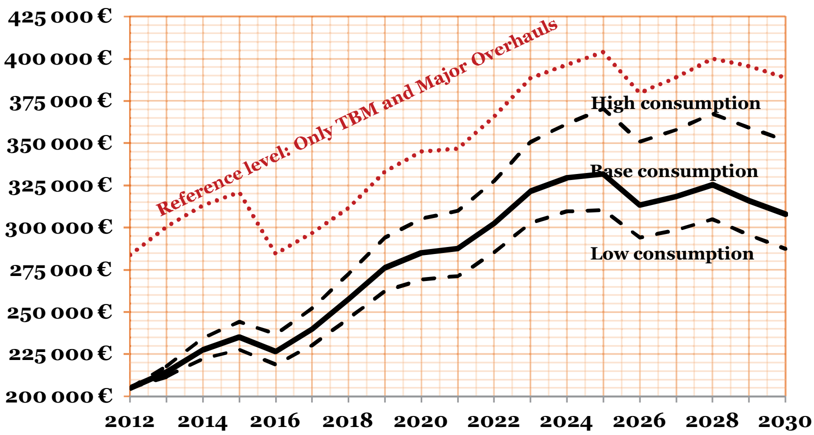


Figure 6-8 Expected quality cost development with different energy consumption scenarios and with the asset management plan described in the Appendix 3. The reference level for the quality cost is evaluated in the situation where there would be no online diagnostics equipment in critical units.

Clearly, maintenance and quality expenditure scenarios are linked together and the expected quality cost NPV with the applied asset management program and base scenario values is 3,1 million Euros. Quality expenses vary also along with consumption development and Figure 6-8 presents the lower and higher scenarios for the expected quality expenses with different consumption development scenarios. The applied lower and higher scenarios lead to a -5 % or +8 % difference in expected NPV when compared to the base scenario result. Figure 6-8 also presents the reference expected quality expense level if no online diagnostics equipment would be in use in the most critical power transformer units, the expected NPV would be in that case 3,85 million Euros in the same evaluation period. The most important factor behind quality expenses is the valuation of cost of interruptions to customers. For example, the quality expenses are 2,7 times higher when Helsinki specific customer interruption cost valuation presented in the Table 3-4 are applied and compared to base case with national values. Although, Helsinki CIC-value researchers stated that the amount of data behind city specific CIC-valuation is limited in this study case, especially compared to nationwide research, and so applicability is limited /36/. Basically CIC-valuation is also societal question and it is more justified to use national CIC-values as a base reference because the statistical data set behind the valuation is much larger.

Sensitivity Analysis for the Overall expenses

One essential aspect of dynamic scenario modelling is to recognise overall expenditure effects for different cost factor changes. The following sensitivity analysis is from the scenarios applied to the DSO's power transformer fleet asset management described in this chapter.

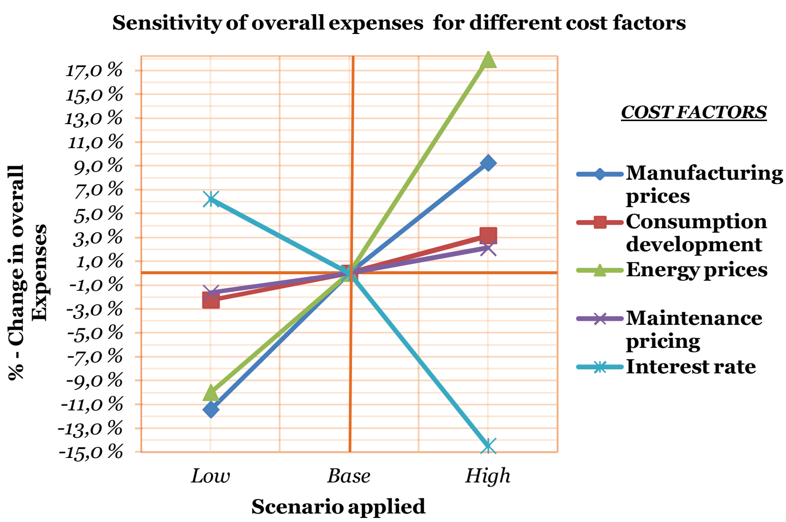


Figure 6-9 Overall sensitivity for different cost factors on the overall expected net present value (eNPV) of the asset management costs described in Appendix 3. /20 visualisation applied/

In this sensitivity evaluation, the high scenario for the energy price increase in overall asset management expenses is 18 percent higher in the period from 2014 to 2030. Changes in the material prices and interest rates also change the overall output significantly. These sensitivity levels are always on the move, and are affected by changes in the global and local economic situation. The sensitivity analysis is made by changing the above mentioned cost factors by one at a time. In the real world, these factors are moving continuously, but still this evaluation shows the cost factor's significance in asset management planning.

6.2 Major Overhaul Assessment

The asset manager needs to find a reasonable balance between maintaining the current asset base and renewing. One real case example is a power transformer major overhaul assessment, concerning whether to maintain the unit longer or renew faster, what the most reasonable solution is, how it is linked to global economy and what are the limit values when applying a major overhaul. A major overhaul is beneficial if the positive gains outweigh the expenses associated with the negative outcomes.

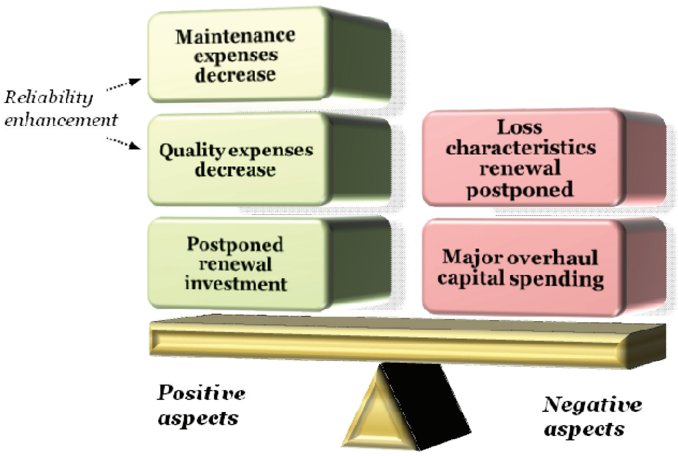
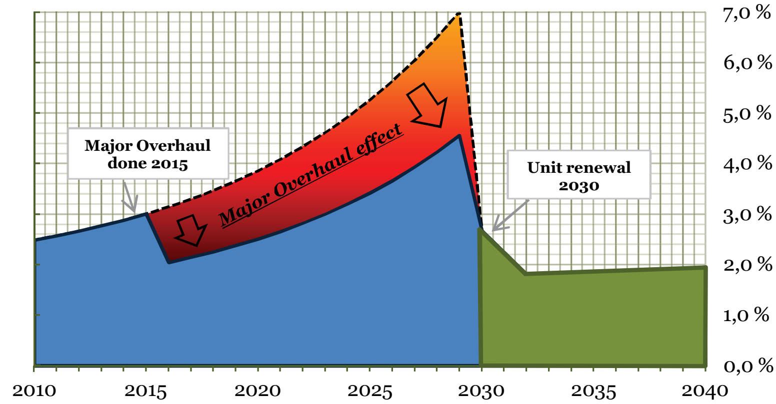


Figure 6-10 Positive and negative aspects of a power transformer major overhaul on an overall scale which is affected by the general economy and unit criticality.

The positive and negative effects are determined by the unit criticality, the applied asset management plan and the global economic situation, and can be divided into the elements in Figure 6-10. One part of the overall analysis is to evaluate the expected economic benefits of the reliability enhancement due to the major overhaul. This partial evaluation is made for the DSO's power transformer T44 unit, which is approaching its major overhauls year 2015 according to a deterministic asset management plan. Major overhauls are scheduled for the T43 and T44 – units, which will have been 24 years in operation by the year 2015. As described in Chapter 5.3.4 a major overhaul decreases the power transformer fault rate by 35 percent with one year latency. The unit is scheduled for renewal after 40 years in operation and so a major overhaul will enhance the unit's reliability between 2016-2030. The following figure presents the fault rate decrease and its economical effect on quality and maintenance expenses.

a) **Major overhaul effect on T43 power transformer fault rate**



b) **Fault rate decrease effect on quality and maintenance expenses**

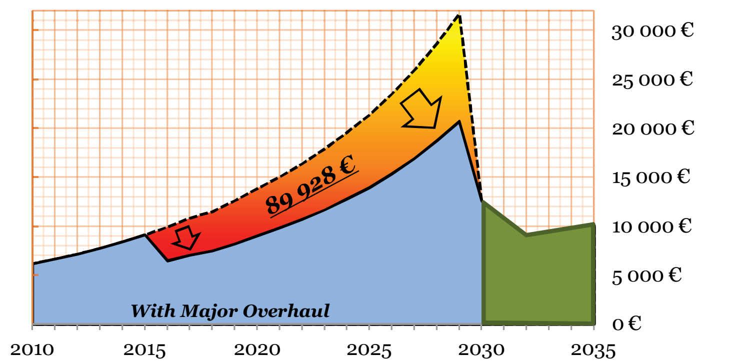


Figure 6-11 a) Major overhaul effect on power transformer fault rate and b) fault rate decrease effects on the expected annual sum of quality and maintenance expenses. This single reference assessment is made with base scenario values and without any other preventive maintenance.

The benefit sum for reliability enhancement in this partial analysis is 89 928 € and the NPV is 58 136 €. 71 % is due to expected quality expense reduction, and 29 % from reduced corrective maintenance expenses. It is clear to say, that reliability improvement is significant, but all other aspects, such as capital and operational expenses, need to be taken into account as well, for a comprehensive assessment.

6.2.1 Major overhaul versus Renewal

This assessment deals with the question of whether to do the major overhaul after the mid-point of the operational life-cycle and thus prolong the operational life-time or whether it is more beneficial to perform only light maintenance and make the renewal power transformer investment earlier. The reference assessment is made for a single power transformer with base scenario values, then continuing with a sensitivity analysis using lower and higher scenario development. Unit T43 is located in the same substation as unit T44, both of which are planned for major overhaul in 2015, according a current asset management plan.

The first option is to perform a major overhaul on power transformer unit T43 after 25 years in operation, in 2015. After the major overhaul, the units are expected to last 15 years more in operation until renewal in year 2030. The second option is to apply only lighter maintenance and renew the power transformer unit when the expected fault rate reaches the same level as in the first option's renewal year, as described in the following figure.

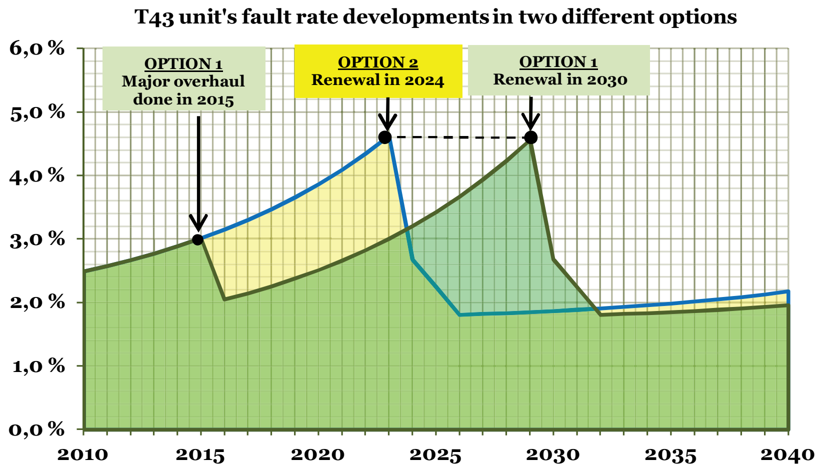


Figure 6-12 Fault rate developments in two different options. Option 1: major overhaul in 2015 and renewal in 2030 and Option 2: without major overhaul and renewal in 2024, when fault reaches the renewal point of option 1.

The fault rate decreases from three to two percent after major overhaul in the year 2016 and gradually rises with power transformer ageing to the renewal point in 2030, which is 4,6 % in this evaluation. If a major overhaul is not performed then the unit reaches the renewal point six years earlier, in 2024. The first option includes capital investments for major overhaul in 2015 and renewal in 2030, and the expected net present value in 2015 for these investments is 412 k€ according the base scenario values. The second option includes capital investments for renewal in 2024, and the expected present value is 359 k€. The second option seems to be more promising solution when considering only capital expenses, but let us see how expected annual expenses are affected in this case.

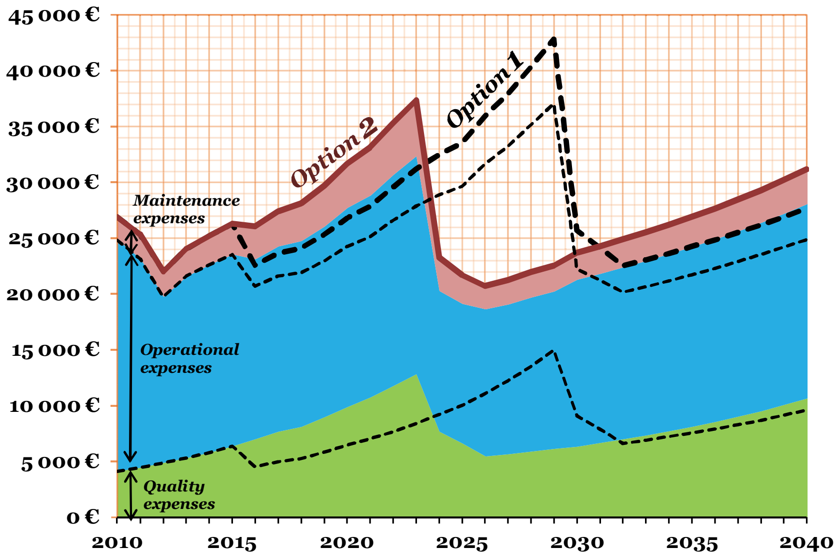


Figure 6-13 Expected annual expenses for power transformer T43 in two different asset management options with base scenario values. The expected annual expenses are the summary of operational, maintenance and quality expenses, and their shares are represented by dotted lines for option 1 and with colored areas for option 2.

The expected annual expenses differ after a major overhaul in 2015, where quality and maintenance expenses decrease in the first option while operational expenses are equal between the two options. The second step change is due to the scheduled renewal in the second option, which decreases all the annual expenses as well: quality and maintenance expenses due the higher reliability of the renewed unit and also the operational expenses, because of the lower characteristic losses. The third step is when power transformer is renewed in 2030 in the first option.

Table 6-2 Expected net present values in the beginning of the year 2015 for the two different asset management options for power transformer T43. Time period for net present value calculation is 2015-2040.

(eNPV)	**Option 1**	**Option 2**
Capital expenses	384 535 €	358 786 €
Operational expenses	254 367 €	237 142 €
Maintenance expenses	44 405 €	45 875 €
Quality expenses	116 889 €	119 968 €
SUMMARY	**800 196 €**	**761 771 €**

The assessment of these two fixed options with the base scenario values indicates that the second option is 38 400 € cheaper overall. The major overhaul enhances the unit's reliability and decreases the expected quality and yearly maintenance expenses, but in this case these enhancements are overrun by higher capital costs and operational expenses. An evaluation with only one scenario reflects only a single point from the possible outcomes, and in turbulent economic environment is not sufficient. Asset management scenarios include many future valuations with uncertainty and therefore analysis with other economic scenarios gives information about the sensitivities for the cost factors behind the overall expenses.

6.2.2 Sensitivity Analysis for Major Overhaul

The major overhaul assessment with the base scenario values for the T43 unit indicated that the second option of earlier renewal is more cost efficient. A sensitivity analysis is now made to analyse how strong this conclusion is in the different economic environments described in the scenarios in Chapter 4. The central cost factors in this case are the expected power transformer and energy pricing, long-term interest rates and maintenance expense development. The sensitivity analysis is presented for one cost factor at a time. For example, the first option of maintaining the power transformer unit longer in operation actually lead to 7 percent higher expected operational expenses compared to the second renewal option.

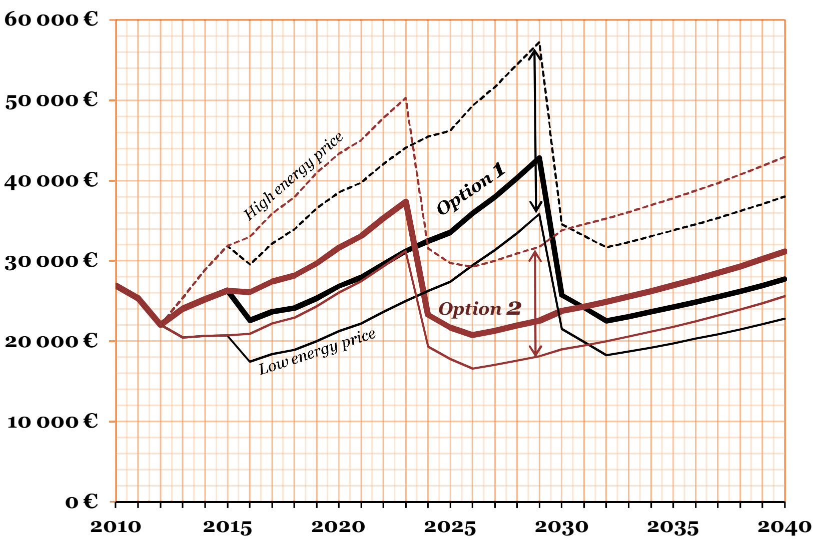


Figure 6-14 Expected annual expenses with the different energy price scenarios presented in Chapter 4.2.4 for power transformer unit T43 with alternative asset management options.

Different energy price scenarios clearly have a significant effect on expected overall expenses and also on the relative cost difference between the two options. The expected operational expense net present value for both options varies from -32 % to +61 % with the lower and higher energy price scenario. The more interesting part in the sensitivity analysis is to see how the relative expense difference between the options changes. The analysis shows that with lower energy prices, the difference between the two options narrows 14 percent and with higher values the difference grows 29 percent. Lower energy prices narrow significantly the cost difference between the options, but according to this there is still no need to change the conclusion in the assessment. Cost factor sensitivities are assessed for all the factors, e.g. the effect of interest rates, manufacturing and maintenance expenses in the table below.

Table 6-3 a) Cost factor sensitivity analysis for the expected overall net present valuation of the two options, maintaining or renewing power transformer unit T43. b) The expense difference between the two options and the relative change compared to the cost difference with the base evaluation.

a)	Option 1		Option 2	
	low	*high*	*low*	*high*
Manufacturing prices	740 371 €	874 248 €	693 546 €	846 635 €
Consumption and energy price development	693 533 €	1 055 726 €	661 159 €	1 000 818 €
Energy prices	719 575 €	955 597 €	686 623 €	906 051 €
Maintenance expenses	783 873 €	831 358 €	754 213 €	771 806 €
Interest rate	868 234 €	648 630 €	815 796 €	637 202 €
Reliability information	735 940 €	895 936 €	695 716 €	860 160 €

b)	Difference		Sensitivity	
	low	*high*	*low*	*high*
Manufacturing prices	46 824 €	27 614 €	**22 %**	**-28 %**
Consumption and energy price development	32 373 €	54 909 €	**-16 %**	**43 %**
Energy prices	32 951 €	49 545 €	**-14 %**	**29 %**
Maintenance expenses	29 661 €	59 551 €	**-23 %**	**55 %**
Interest rate	52 439 €	11 428 €	**36 %**	**-70 %**
Reliability information	40 224 €	35 776 €	**5 %**	**-7 %**

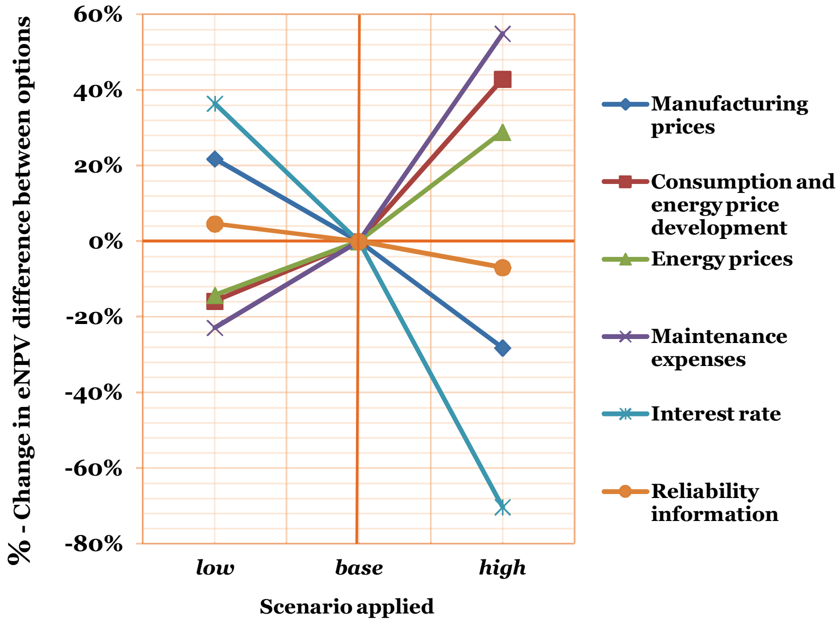


Figure 6-15 **Sensitivity of the overall conclusion between the two asset management options for power transformer T43. The Y-axis change percentage is calculated from the difference in expected net present values for options one and two, with low, base and high economic scenarios.**

Cost factor changes that narrow the cost difference between the two options are essential, regarding the main conclusion of the assessment. It is important to recognise the factors that may cause the overall conclusion to change and in which way that might happen. In this evaluation, the economic interest rate is one of the key parameters in the evaluation because the key difference between the options is related to the time value of money; hence intensive power transformer unit maintenance postpones renewal investments. Secondly, the development of power transformer manufacturing prices also dictates whether is it reasonable to renew or to maintain, and if manufacturing prices rise then it becomes more economical to maintain current units longer. Vice versa, if manufacturing prices decreases it is not sensible to spend lot of effort on maintenance, especially if labour costs associated with maintenance are not lowered in the same time frame. Thirdly, maintenance expenses and in particular the cost of major overhaul, change the balance between the two options significantly. A key reason is that major overhaul expenses occur in the first year of the assessment and therefore the value of money is a lot higher than in the renewal investment in the following decade.

Besides the economic parameters, there is also the need to analyse the technical factors behind the conclusion. One of the central technical factors is power transformer reliability information in the modelling. Inferior and superior fault rates were determined based on the RTE statistics described in Figure 5-9. The central target in the first option is to increase the power transformer's reliability with major overhaul and a sensitivity analysis was performed to reveal whether varying the fault rate level would significantly affect the conclusion. If the fault rates changes to the superior rate in both options, the expense difference between the options decrease mildly by seven percent and almost same happens the other way around with inferior fault rates. Nevertheless these results do not point to other conclusions in this matter. Only in the situation where the lower inferior fault rate is used for the first major overhaul option and the higher base fault rate for the second renewal option, then the overall result points to a conclusion that favours the first option. The situation where a 25 years old power transformer unit has significantly better reliability than the newly renewed power transformer unit is possible, but the probability is very low. The more likely situation is that the major overhaul reliability enhancement is more significant than expected. A sensitivity analysis shows that if the major overhaul is expected to reduce the power transformer fault rate by 55 % instead of the applied 35 % reduction, the expected maintenance and quality costs would decrease by 24 k€ in the first option, but still the overall conclusion favours the second option.

The second important technical factor in the option assessment is the applied preventive maintenance intensity. Both options were analysed that only the asset management plan which included only expected corrective maintenance actions besides the major overhaul in the first option. The following assessment presents the maximum monetary effects achieved by the major overhaul when the reliability enhancements are valued higher in order to avoid interruptions and expensive corrective maintenance actions. The DSO's current asset management plan includes time-based maintenance for every unit and condition-based maintenance for older or critical units. So the sensitivity analysis for the maintenance intensity effect is made with TBM and CBM applied to the T43-unit for both options. In both cases preventive maintenance noticeably reduces overall costs by seven to eight percent, 57 k€ in the first option and 59 k€ in the second option, but the difference in the overall expenses increases mildly. The main conclusion still holds that the second option is better overall.

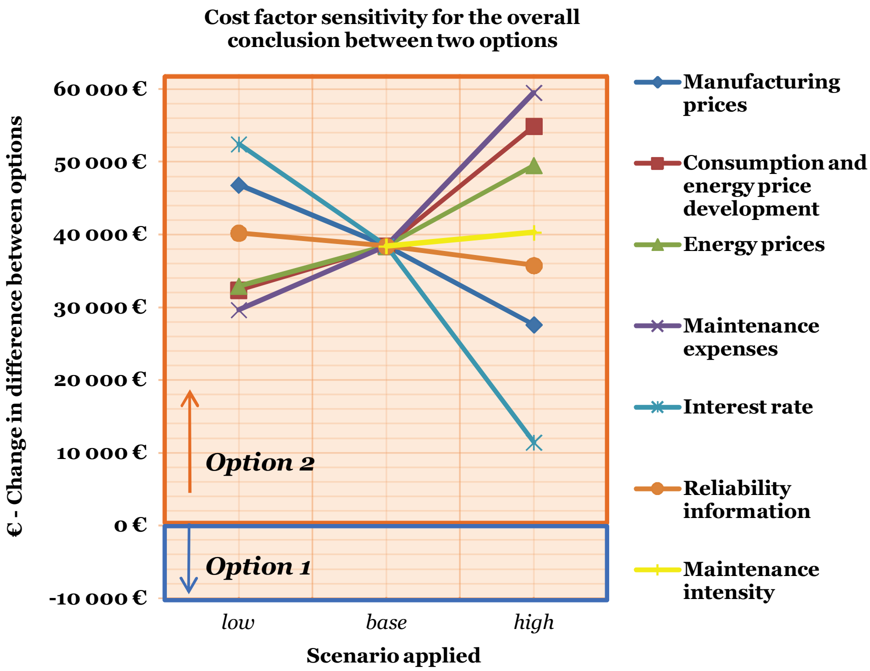


Figure 6-16 Sensitivity analysis and limit values for the base conclusion of whether to maintain or renew the power transformer unit T43.

The assessment shows that the choice of whether to maintain and renew is highly related to the economic situation and general interest rates which dictate the current valuation of expenses over time. The interest in the base evaluation was 5,25 percent due to the low general interest rates during the global economic downturn. The preceding DSO analysis of whether to apply major overhaul or not, was performed during the higher general interest rates, and if the evaluation would be performed again applying the same interest rate as high as 8 %, then the major overhaul option would be better. A higher interest rate would not concentrate the evaluation on the expenses occurring later on, and so the actions which postpone large individual investments become more tempting when capital is expensive.

In addition, if major overhaul expenses could be lowered by performing only the very essential actions that enhance reliability with a high expectancy and limiting other actions that have lower expectancy for reliability enhancement. If major overhaul expenses would be then around 33 k€, it would then be sensible to overhaul the T-43 unit. Otherwise, in the current economic situation, it seems reasonable not to perform a major overhaul but the renew unit earlier, around the year 2024. Also assessments with upper and lower CIC-valuations mentioned in the Equation 3.23, do not change the conclusion. These conclusions apply to the other power transformer unit T44 in the same substation as well.

6.2.3 Summarising another reference case

One single rule of thumb for the entire asset base can form a functional solution for a distribution system operator, but it cannot be considered economically pertinent decision-making when the essential cost factors are on the move all the time. Concerning major overhaul necessity, one analysis cannot determine what the right balance for the whole fleet is. In the DSO's asset management plan there is also a major overhaul scheduled in 2015 for units T37 and T38 in the same substation. The same analysis of whether to maintain or renew shows that in this case the difference between the two options is smaller.

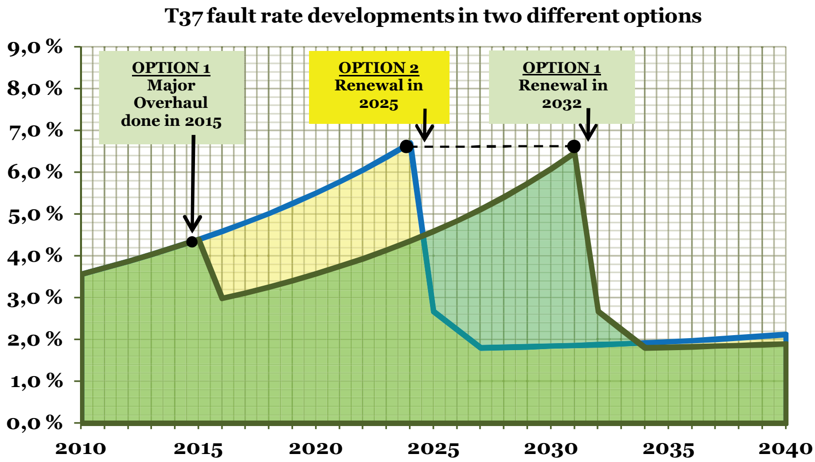


Figure 6-17 Expected fault rate development scenarios with to asset management options for power transformer unit T37.

Power transformer unit T37 was manufactured in 1992, but still it has higher expected fault rate than unit T43. The reason for that is in the T37-unit's suboptimal OFAF-cooling settings from 1992 to 2006, whereas ONAF-cooled unit T43 had no cooling system defects. The OFAF-cooling defect for power transformer fault rates was presented in Chapter 5.7. A reference asset management plan for unit T37 is formed with deterministic principles, but due to the OFAF-cooling defect major overhaul is scheduled two years earlier compared to unit T43. Dynamic scenario assessment detailed results are presented in Appendix 5.1 and the overall conclusion in the following figure.

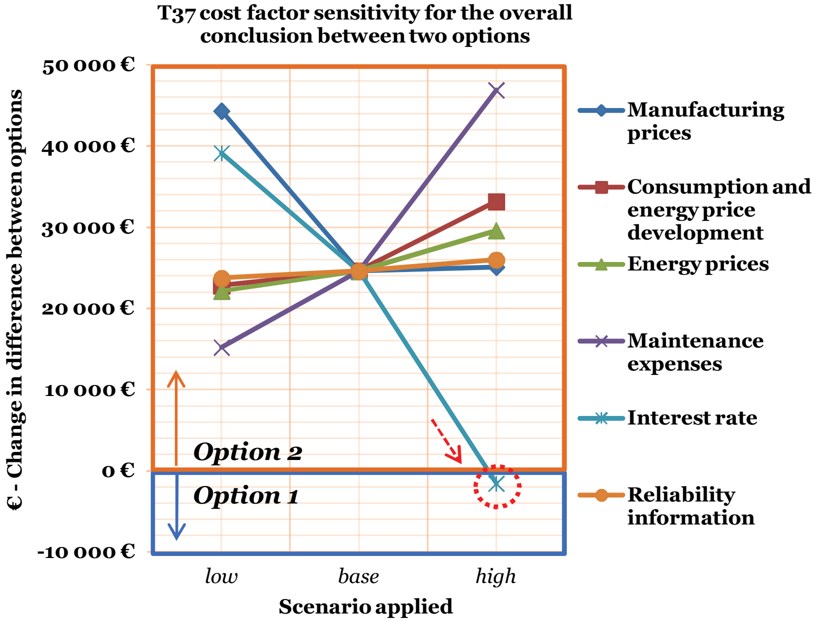


Figure 6-18 Sensitivity analysis and limit values for the base conclusion of whether to maintain or renew power transformer unit T37. Detailed results are described in Appendix 5.1.

As the overall expense difference between the options of maintaining or renewing a power transformer unit approaches the same cost level, the sensitivity analysis with different scenarios becomes more important. The figure above shows the situation where a change in one cost factor can shift the overall conclusion the other way around, when the increased general interest rate leads to value major overhaul as the more suitable solution. Dynamic scenario modelling is needed more when the global economic situation varies. It is not so unbelievable that the DSO's overall interest rate for capital investments could rise to 7,4 percent. This is the reason why an asset manager needs to follow global economic long-term trends and to be aware of the dependencies around the distribution system asset management.

6.3 Dynamic Risk Matrix for Asset Management

The asset manager is targeting for a certain balance between investments, operational spending and risks within a changing environment. One basic tool in analysing asset performance related risks is to use a criticality-condition matrix. The risk amplitude is determined by the probability of failure and its consequence, whereas the risk matrix is a summary view for risks associated in the evaluated subject, such as in the transformer condition matrix in Figure 2-11. Dynamic scenario modelling can assess risk development dynamically by combining the necessary information of failure probability and consequence development over time for different power transformer units.

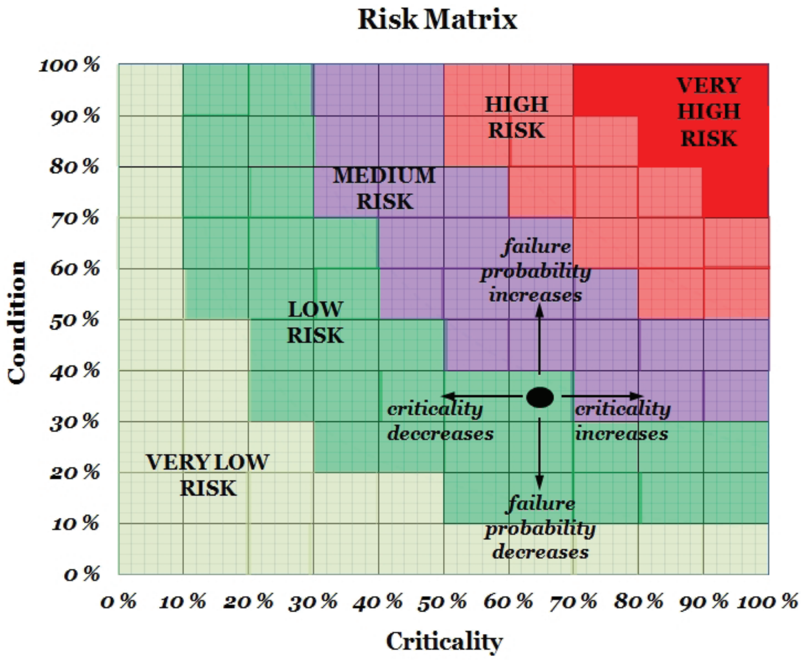


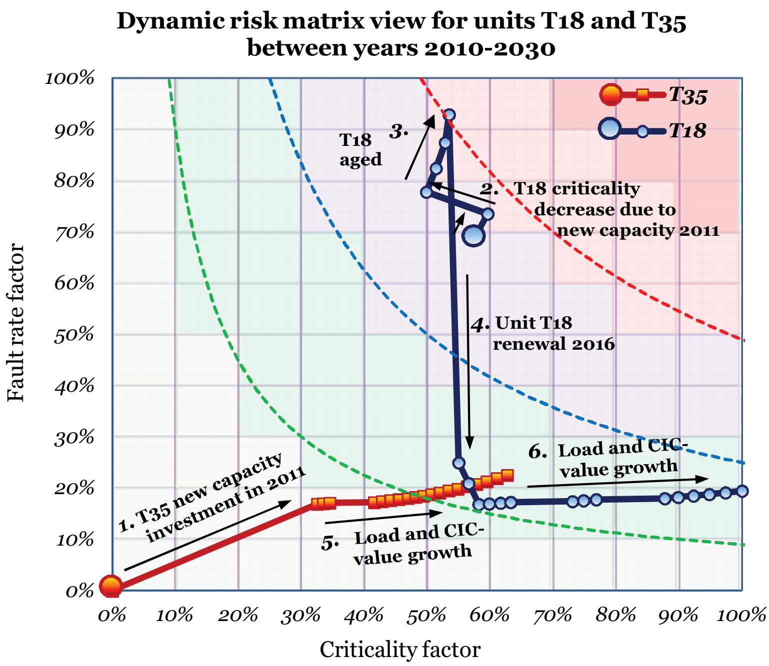
Figure 6-19 Risk matrix, which is applied for the power transformer fleet with different economic scenarios to describe different asset management environments and making it dynamic over time and for different actions.

The reason for risk modelling is in categorising information to plan targeted actions to reduce failure probability and to mitigate failure consequences. A risk matrix can be extended to expected future development with dynamic scenario modelling. Dynamic scenario modelling is now applied to form a power transformer unit's risk matrix to gain an overview about the risk development with a certain asset management plan.

Table 6-4 Factors that define a power transformer unit's position and its movements in the risk matrix above.

Criticality	Failure probability
Characteristic consumption development	*Ageing*
New consumption	*Operational history*
New capacity investments	*Preventive maintenance intensity*
CIC-value development	*Diagnostic intensity*
Customer profile changes	*Renewal investments*

A dynamic risk matrix takes the earlier described factors into account that define the power transformer unit's movements in the risk matrix over time. Two power transformer units are chosen to demonstrate a dynamic risk matrix in Figure 6-20 below. The first unit T18 is nearing the end of its operational life with 37 years in operation and the second unit T35 was newly invested in 2011 to add new capacity to a new neighbouring substation. The new T35 unit is taking (1.) the load from the other neighbouring substation power transformers, e.g. the T18 unit, which is visible in the figure below (2.). Unit T18 is aged and the fault rate increases rapidly and reaches a high risk level (3.), which leads to unit renewal (4.). Movements in periods (5.) for unit T35 and (6.) for renewed unit T18 are caused by load growth, increased CIC-values and mild ageing process.



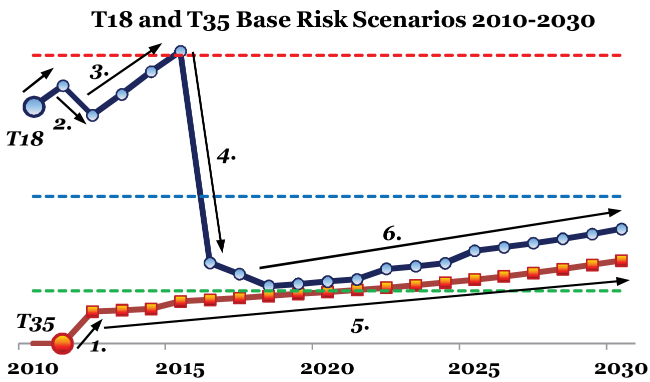


Figure 6-20 **Dynamic risk matrix and risk development from 2010 to 2030 for the power transformer units T18 and T35 with base scenario values.**

6.3.1 Risk ranking development

An essential usage for a risk matrix scenario is to evaluate unit risks to the entire fleet's risks. A dynamic risk matrix can reflect the risk ranking developments over time in order to target preventive maintenance and renewal actions where they have the largest effect on risk reduction.

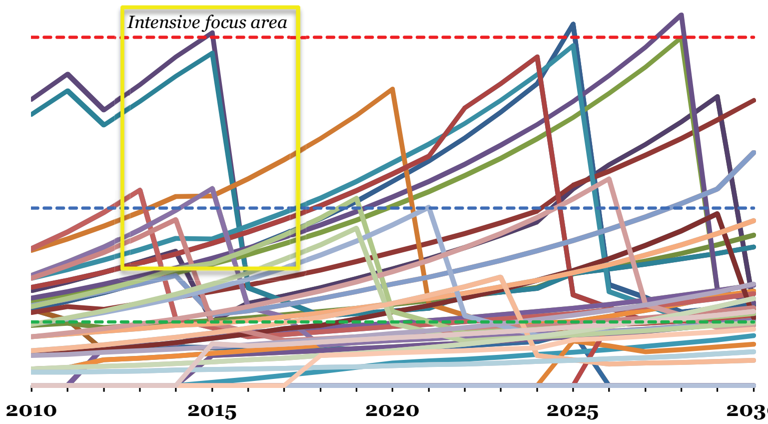


Figure 6-21 Power transformer fleet base fault risk scenarios and intensive focus area in reducing overall risks in asset management.

Table 6-5 Eight highest ranking risk units in the DSO's power transformer fleet and the unit with the lowest risk and risk average for the whole fleet between 2013-2014.

Highest	2013	2014	2015	2016
1.	*T18* 85 %	*T18* 92 %	*T18* 99 %	*T26* 58 %
2.	*T19* 80 %	*T19* 87 %	*T19* 93 %	*T25* 45 %
3.	*T39* 55 %	*T26* 53 %	*T41* 55 %	*T27* 43 %
4.	*T40* 55 %	*T41* 49 %	*T42* 55 %	*T28* 43 %
5.	*T26* 49 %	*T42* 49 %	*T26* 53 %	*T24* 39 %
6.	*T41* 44 %	*T47* 47 %	*T25* 41 %	*T14* 39 %
7.	*T42* 44 %	*T25* 41 %	*T27* 40 %	*T15* 39 %
8.	*T47* 42 %	*T11* 38 %	*T28* 40 %	*T48* 38 %
Lowest	*T62* 4 %	*T62* 4 %	*T31* 1 %	*T31* 2 %
Fleet average	23 %	24 %	24 %	21 %

Figure 6-21 illustrates the power transformer fleet risk scenario development and Table 6-5 also shows that the associated power transformer unit risk can be from 20 to even 99 times higher when a high risk unit is compared to the low risk unit. This real difference is a significant reason to follow risk development and intensify maintenance actions in high risk units, and decrease maintenance activities where costs exceed overall benefits. The overall power transformer risk ranking scenario for the whole fleet is described in Appendix 6, and is used in the maintenance assessment.

6.4 Maintenance Assessment

Simply expressed, a preventive maintenance action is beneficial when the maintenance expense is less than the achieved benefit in terms of quality expenses and in avoiding expensive corrective maintenance. The balance in this matter with power transformers is related to several unit characteristics: location, customers, labour cost level, expected maintenance effects and diagnostic expenses. Power transformer risk ranking development is an applicable tool in determining preventive maintenance levels for different units. Expected effects for different maintenance intensities are described in the fifth Chapter in the Figure 5-16 event tree.

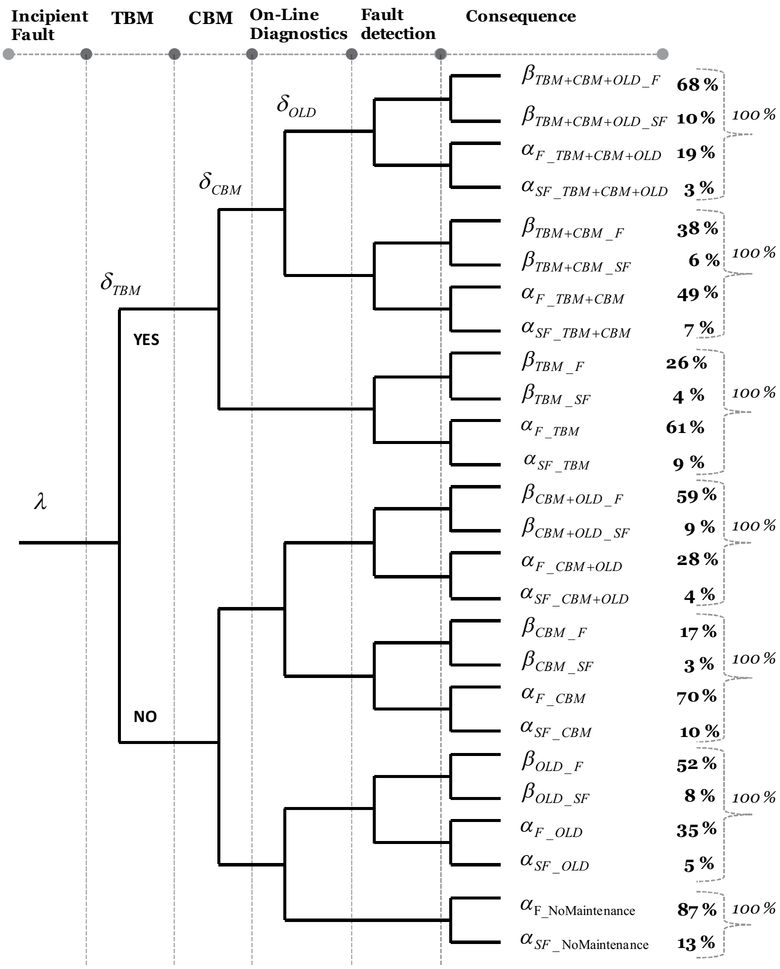


Figure 6-22 Event tree analysis for power transformer faults with different preventive maintenance intensities. Percentage values for alpha factors denote the share of failures which lead to interruptions and beta factors denote the share prevented by maintenance.

The Power transformer fault rate is the same as the failure rate when no preventive maintenance is applied. 87 % of faults lead to interruption and 13 % to serious failure with longer interruption and higher repairing expenses. On the other hand, when the preventive maintenance intensity is very high, with time-based, condition-based and online diagnostics, then 78 % from the incipient faults can be detected and corrected before interruption and only 21 % lead to interruption. It is also clear that intensive maintenance is costly, so it is reasonable to balance intensity based on the risk ranking. Maintenance expense modelling values applied in the maintenance assessment are described in Appendix 6.2.

6.4.1 Benefit scenarios and maintenance intensity

Benefits and costs for different maintenance intensities are evaluated with dynamic scenario modelling in order to recognise limit values for where to apply preventive maintenance and with which intensity. Time-based maintenance, where certain basic maintenance actions are performed frequently, is common practice in power transformer asset management.

Time-based Maintenance

In the focus DSO's asset management, power transformer TBM includes basic maintenance every second year and tap-changer maintenance every sixth year. TBM effects are described below for the unit T55, which has a relatively low risk level compared to the whole fleet.

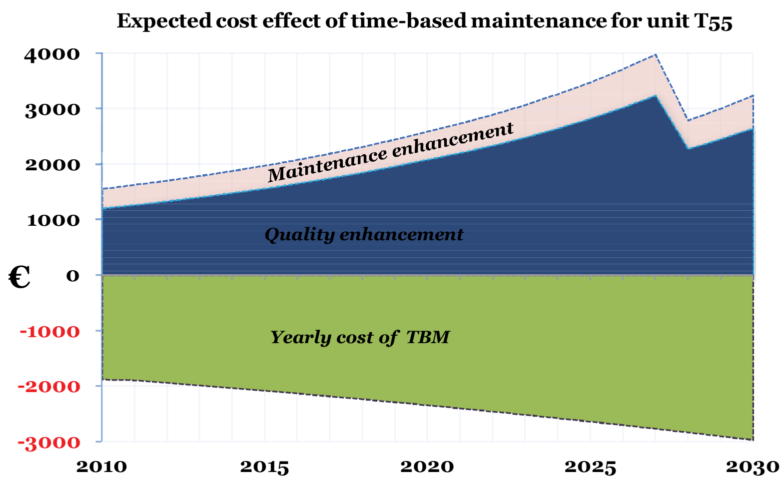


Figure 6-23 Benefits and costs related to time-based maintenance implementation for power transformer unit T55.

Benefits and costs for the reference power transformer unit are assessed with base scenarios values. In the evaluation, time-based maintenance and related condition measurements are expected to detect 30 percent of the incipient faults, hence 26 percent of the faults lead to normal level preventive fault maintenance and 4 percent of the cases correct serious incipient faults. The net present value in the year 2013 for expected overall benefits, comprising of quality enhancements and avoided corrective maintenance, are 29 600 Euros, and the overall costs for TBM are 26 500 Euros.

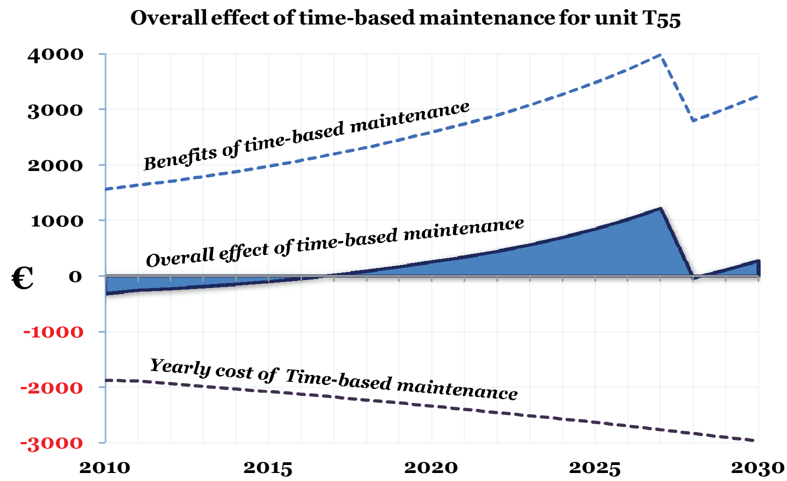


Figure 6-24 Development of time-based maintenance expenses and their benefits summarised in terms of overall effect with the base scenario conditions for power transformer unit T55.

According to base scenario valuation time-based maintenance the yearly costs currently exceed associated benefits; hence the overall cost effect is negative until the year 2017 along with the criticality increase and especially with the ageing of the unit. Unit was renewed in 2004 and is located in a sub-urban area supplying mainly residential consumption. The sudden decrease in the maintenance benefits is due to the currently scheduled major overhaul and subsequent expected reliability enhancement.

Condition-based Maintenance

Time-based maintenance is intensified with condition-based maintenance when a power transformer is aged or for other reason the expected incipient fault rate is higher than normal in the fleet. If the power transformer unit is supplying very critical consumption, intensified maintenance can also be applied to assure continuous supply. Condition-based maintenance will reduce interruptions when the CBM expected detection rate is 20 percent of the incipient faults before actual failure.

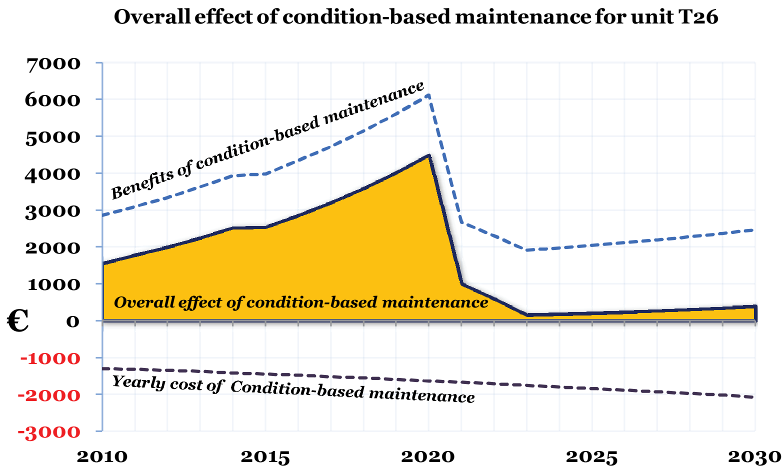


Figure 6-25 Base scenarios for condition-based maintenance costs, benefits and overall effect development for power transformer unit T26.

Unit T26 is located closer to the city centre compared to the unit in the TBM example and most of the consumption is from the public sector with higher criticality. In this case, reliability enhancements are valued high and maintenance benefits clearly exceed CBM costs. Net present value in the year 2013 for expected overall benefits, comprised from quality enhancements and avoided corrective maintenance, is 39 100 Euros and overall costs for CBM are 17 700 Euros from 2014 to 2030. Condition-based maintenance is lighter than time-based maintenance from the expense point of view and it is usually applied along with TBM. If CBM is performed without TBM, the overall result is a lighter TBM and a lower detection rate.

Online Diagnostics

Online diagnostics technology has developed significantly in the recent years and prices have also decreased from the DSO's point of view into reasonable levels. The Cigre guide on the economics of transformer management expects online monitoring to detect 60 percent of the incipient faults and this estimation is used in the scenario modelling as well /59/. Online diagnostic equipment pricing is expected to decrease along with its wider deployment in electrical network asset management, although the installation expenses and costs of continuous equipment operation and maintenance are expected to slightly increase. Online equipment costs are expressed in fixed capital annuity with 10 years of operational-time and with 5 % yearly costs of the investment price. Online diagnostic equipment base price with installation in this evaluation is 16 900 Euros in the year 2010 and the expected price development is described in Appendix 6.2.

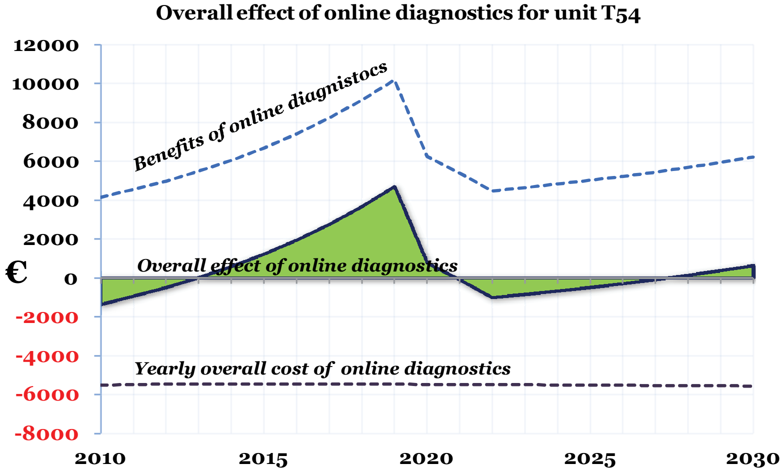


Figure 6-26 Base scenario for the overall effects of online diagnostics applied to power transformer unit T54.

The net present value in the year 2013 for expected overall benefits, comprised from quality enhancements and avoided corrective maintenance, is 71 600 Euros and the overall costs for continuous online diagnostics are 60 700 Euros between 2014 and 2030. Figure 6-26 shows that there are periods in the unit life-cycle when online diagnostics can bring clear benefits and these periods are located at the end of the operational time or one option is when the unit is nearing the major-overhaul. Power transformer unit T54 was installed in 1980, and so before the unit reaches its renewal point, the benefits of online diagnostics are at their best.

Intensive Maintenance

There are power transformers units which are supplying critical consumption and intensive maintenance may benefit even the maintenance costs are many times higher than TBM and CBM. The risk ranking result for the DSO fleet in Table 6-5 indicates that unit T18 has the highest risk in the fleet. In the following assessment, time-based maintenance, condition-based maintenance and online diagnostics are applied to the unit T18. While yearly costs for such extensive maintenance are reaching 10 000 Euros, the benefits can still be significantly larger.

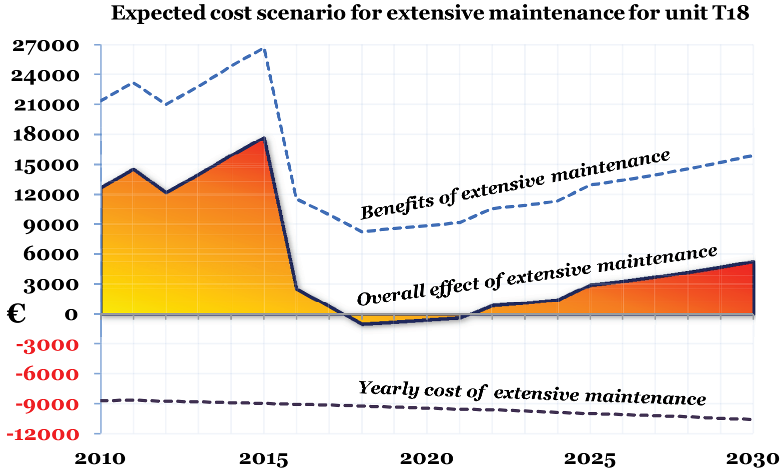


Figure 6-27 **Overall effects of extensive maintenance applied to the highest risk ranking power transformer unit T18.**

The expected annual benefits for extensive maintenance from combined TBM, CBM and online diagnostics reach 26 700 Euros in the year 2015. The net present value in the year 2013 for expected overall benefits, comprised from quality enhancements and avoided corrective maintenance, is 151 000 Euros and the overall costs for continuous extensive maintenance are 105 000 Euros between 2014 and 2030. Unit T18 is located in the city centre and is supplying commercial consumption for the most part 71 % and with such high criticality and ageing unit extensive maintenance is beneficial. It is also important to recognise when maintenance efforts are not useful, due to the expected low benefits, as in the following case for unit T61.

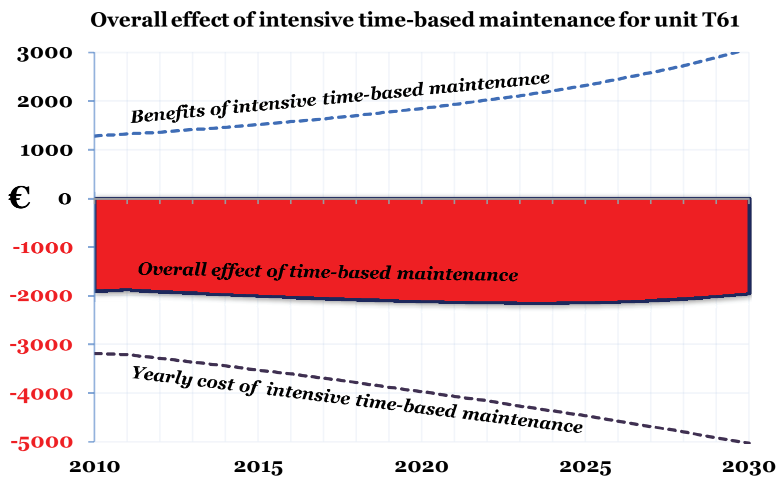


Figure 6-28 **Overall effects of TBM and CBM applied to unit T61.**

It is quite possible, to perform maintenance deterministically with only technical considerations, regardless of the overall benefits of the actions. Figure 6-28 presents an example assessment of the case where TBM and CBM are applied to a newly invested unit T61, where the consumption is mainly residential. The net present value in the year 2013 for expected overall benefits, comprised from quality enhancements and avoided corrective maintenance, is 22 000 Euros and overall costs for continuous intensive maintenance are 44 300 Euros between 2014 and 2030. Intensive maintenance for unit T61 would only increase overall costs applied without balancing the effort and benefits together.

6.4.2 Risk Development and Maintenance Strategy

Physical electrical network asset management should reflect risk development and plan actions that balance overall expenses. Maintenance strategy should be chosen on the basis of the evaluated risk. The following assessment summarises the maintenance effects on the risk matrix in order to find reasonable maintenance intensities based on expected risk development.

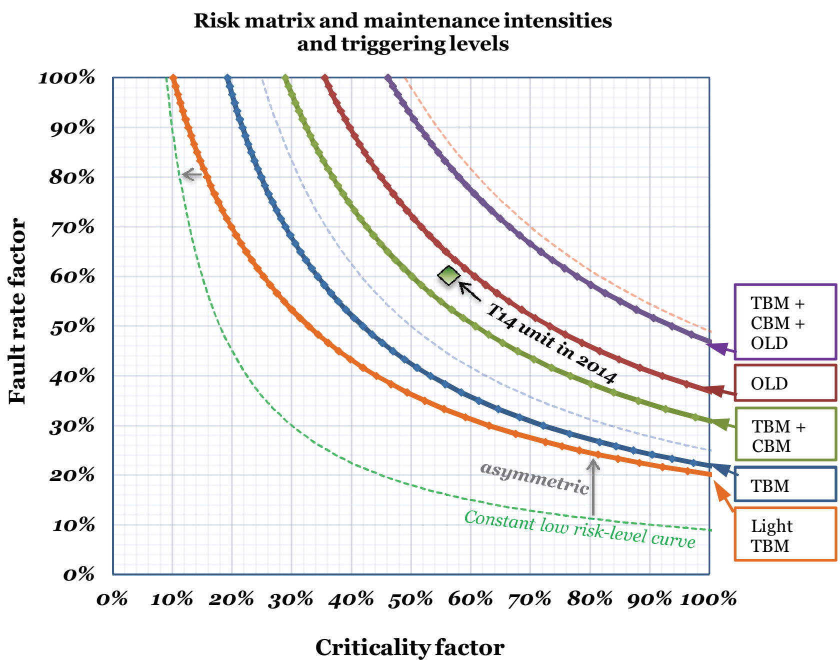


Figure 6-29 Risk matrix presented in Chapter 6.3, where maintenance intensities presented earlier are plotted with triggering levels. The expected T14 unit risk level in 2014 is also described in the figure.

The figure above shows the risk level limits where it is reasonable to apply a certain maintenance intensity to reduce the overall associated risks and expected costs. It is noticeable that the maintenance intensity limit curves are asymmetric compared to the constant risk level curves in the risk matrix. In other words, the maintenance intensity limit curve is not at a constant risk level. This is due to the fact that maintenance reduces the actual failure rate in numerical values more when initial fault rate is higher. This means that when a transformer fault rate is at a high level, e.g., with old units, maintenance can reduce the initial fault rate value more than in a new transformer that already has a low fault rate. As a result, overall expenses decrease due to maintenance more with the older units than new ones.

According to Figure 6-29, the T14 unit risk has exceeded the level needed to implement intensified time-based maintenance (TBM + CBM). It also seems that unit T14 is approaching and is about to exceed the required limit level for online diagnostics in the near future. The same assessment is made for the entire power transformer fleet in order to balance reasonable maintenance intensities with respect to the risk development.

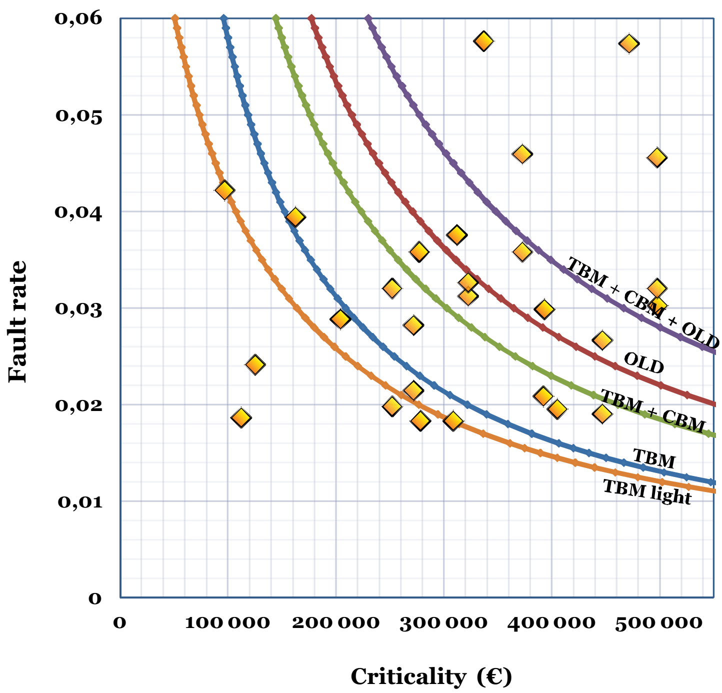


Figure 6-30 Risk matrix plot for the year 2014 for the DSO's entire power transformer fleet risks and reasonable maintenance intensity levels.

The figure above presents a risk-centered maintenance plan for different power transformer units in the year 2014. The x-axis criticality values describe the expected summary of quality and maintenance expenses when the power transformer annual failure probability would be 100 percent, and the y-axis describes the expected power transformer fault rate during the year. Power transformer unit risk levels are continuously changing with the changes in reliability and in criticality. Maintenance intensity limit levels are also changing with the price development of maintenance labour costs and diagnostic equipment.

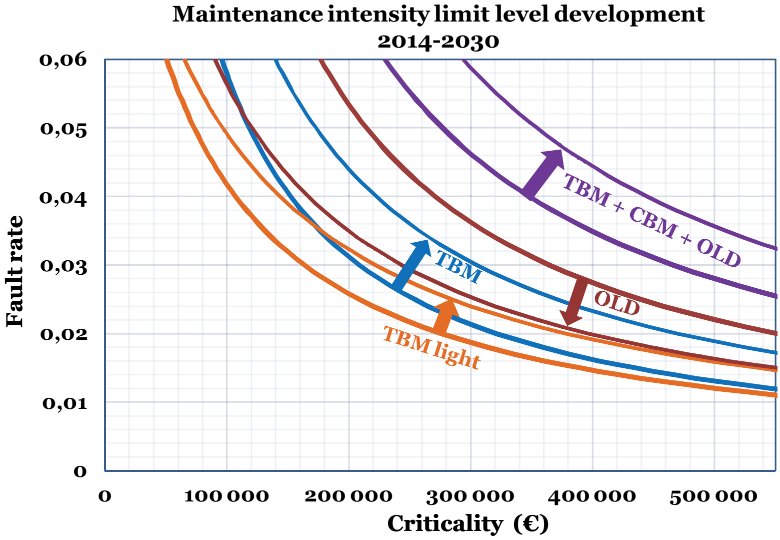
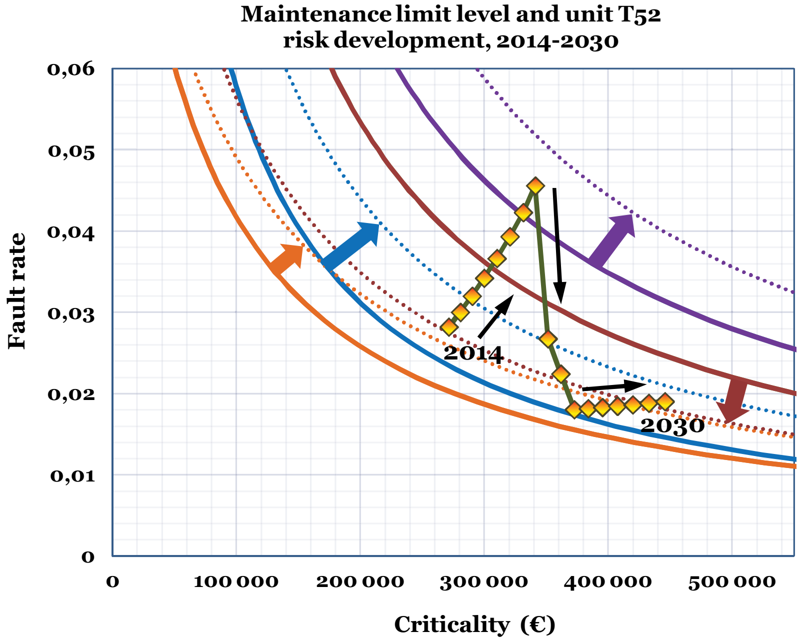


Figure 6-31 Maintenance limit level development between 2014-2030 along with changes in labour costs and in online diagnostic equipment pricing in the base scenario.

Maintenance risk limit levels increase in time-based and condition-based maintenance actions due to the expected slowly increasing cost of labour. Expenses in online diagnostics are not increasing significantly, although diagnostic equipment requires installation and operation, but still the share is only fifteen percents of the OLD capital costs, while the OLD equipment cost is expected to reduce in the long-term. These cost developments seem to lead to a situation where online diagnostics become more beneficial than current time-based maintenance procedures. This development is naturally related to overall labour cost development and diagnostic equipment pricing, but it is still highly probable that online diagnostics will replace some part of the time-based maintenance labour procedures. Of course, if labour cost development is lower, then this change may be delayed but not avoided. The applied maintenance expenses are described in Appendix 6.2.

Dynamic scenario modelling takes these developments of power transformer unit risk position changes and maintenance risk limit variations with time into account. An example assessment result is presented in Fig. 6-32 for power transformer unit T52, which is located in an industrial sub-urban area, has been 31 years in operation by the year 2013 and had a major overhaul in 2000. Currently, renewal is planned around 2022.



	2014		2016		2018		2020		2022		2024		2026		2028		2030
T52	TBM	T+C	T+C	O	O	O	O	O	O	TBM	light	light	light	light	O	O	O

Figure 6-32 Maintenance limit values and unit T52 risk development with a reasonable maintenance intensity programme: T+C= TBM + CBM, O=online diagnostics, light= light TBM.

The maintenance assessment indicates that the T52 unit risk level is optimally reduced with time-based maintenance in 2014, and as the risk level increases with ageing the limit for combined TBM and CBM is reached. Currently the T52 unit is relatively old, and so the incipient fault rate is expected to increase quite rapidly compared to a new unit, meaning that online diagnostics become the optimal maintenance intensity around the year 2017 until the unit is renewed in 2022 according to the planned schedule. After renewal, the unit risk is reduced significantly and time-based maintenance is enough for the first year, and can even be reduced to lighter TBM for the following four years before the online diagnostic level is reached. Of course, before the unit renewal time it would be reasonable to update the relevant information, to see whether is reasonable to include OLD equipment in the unit purchase, which it probably will be. Nevertheless, the assessment results for the near future are the most relevant, and the dynamic assessment should be updated at least yearly. Maintenance assessment is made in the dynamic scenario analysis in a similar manner for the entire DSO's fleet, and the optimal maintenance program with the base scenario conditions is described in Appendix 6.3. The investment schedule in the maintenance assessment is described in Appendix 3.

6.5 Investment Assessment

An essential task for the asset manager is to achieve an overall balance of investments, annual expenses and system performance. Investments are one of the most important single decisions in asset management; hence investment decision effects last for many future decades for central electrical distribution subsystem elements such as power transformers. This assessment is looking forward at power transformer price development and lower and higher projections based on the asset management environmental scenarios presented in Chapter 5. The projected base scenario is also applied when assessing reasonable renewal timing with dynamic scenario modelling. Thirdly, the dynamic scenario modelling is applied to find suitable values for loss capitalisation in the power transformer purchases.

There are benefits in following projections for the price development of commodities that affect power transformer pricing, because rapid movements in commodities market can alter the balance between capital and annual spending in asset management more than changes in technical details. The future price scenarios applied here are generated from publicly available information for the most part. World Bank annual economic prospects can serve in rough estimations, which can then be improved by utilising more detailed information from the investment banking sector, for example.

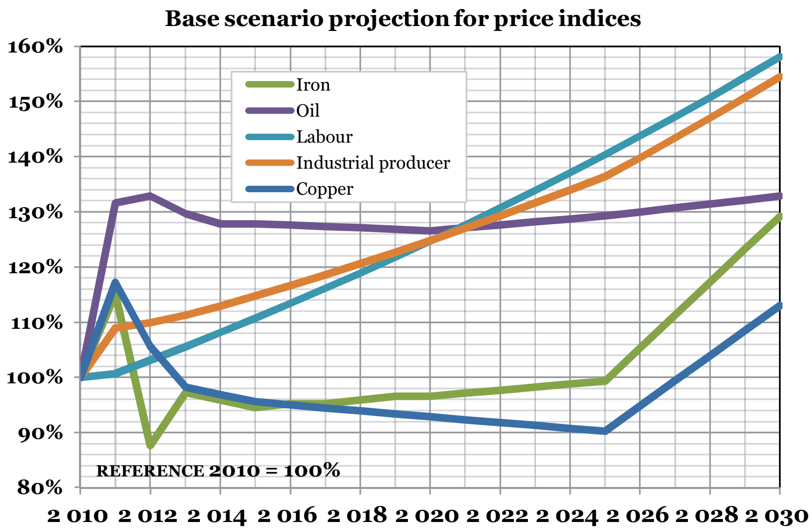


Figure 6-33 Base scenarios for projected future price indices development. Background for the applied projections is described in Chapter 5 and based on values from Appendix 4.

The World Bank commodities development projection in June 2013 evaluate that the commodities boom is fading and prices are not expected to rapidly increase in the near future because of the sluggish general economic situation. Nevertheless, the projection in 2013 is a little more positive than the WB projection in June 2012, which is described in Appendix 7. After the 2000's commodity boom new production capacity was introduced in the markets, which was projected in the Deutsche Bank presentation in Figure 4-5 in Chapter 5. Also, the projection for oil pricing has decreased in the past year, maybe due to the recognised alternatives in traffic over the coming decades and the peak effect of shale gas reserve exploitation in the USA. The purpose here is not to evaluate commodity market development, but to implement fundamental information to assess power transformer price development roughly in the investment analysis, which an asset manager needs to do anyway, whether assuming that price will be stable for the coming decades or applying more detailed estimation. The upper and lower boundaries provide information in the sense of economic turbulence and the commodities boom: upper and lower projections are calculated from the base scenario with average analyst forecasting errors during the commodities boom recorded by Deutsche Bank /28/.

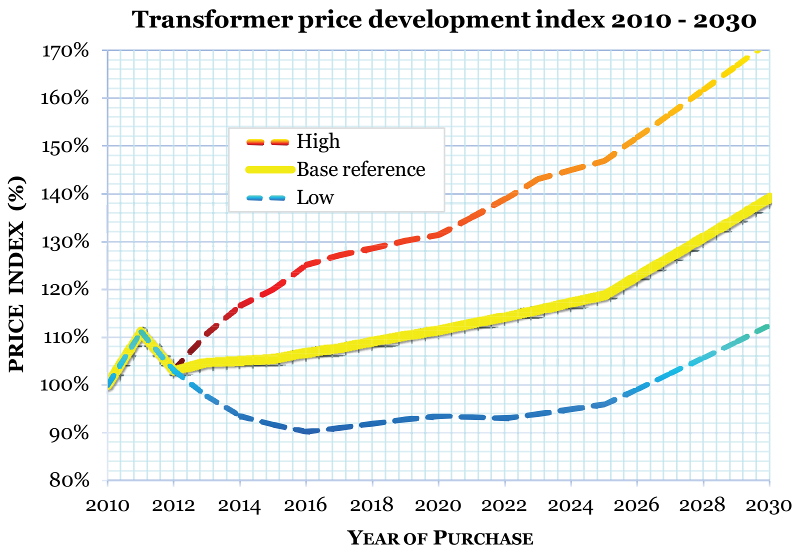


Figure 6-34 Long-term power transformer price index development view in June 2013. The base estimation is constructed applying the Word Bank's base estimations published in June 2013 and average developments for labour and industrial producer costs presented in Chapter 5 and Appendix 4. /67/

The base scenario expectation is quite stable, with a slight price increase in the near future and slowly increasing development in the latter part of this decade. The essential factor behind the commodities development is the amount of global consumption and construction, which has slowed from the last decade pace due to the financial crisis in the western countries. As always with the dynamic scenario assessment, the information for the near future is the most relevant, because these estimations are more accurate and are actually applied in decision-making.

6.5.1 Investment Timing

Simply put, the suitable time for power transformer renewal investment is when the overall expenses of capital, operational, maintenance and quality decrease following the renewal investment. The essential elements in the evaluation of investment timing are power transformer pricing, energy prices, general interest rates, and maintenance and quality expenses. Unit pricing is the central element, but also energy prices can make a real difference when thirty-forty year old units consume much more loss energy. The consumption criticality is also an important factor, which drives earlier renewal investments when high. Interest rates naturally dictate the time value of money and therefore have a significant effect on long-term capital investment.

The presentation of the investment timing assessment is started here with the oldest power transformer unit currently in the DSO's fleet. The unit was purchased in 1972 and has been 40 full years in operation. Major overhaul was performed in 1993 and, with a 40 year deterministic scheduling; the renewal investment time is now in 2013. The unit is located in a suburban area and is supplying residential consumption for the most part. The transformer's overall expenses are a sum of operational, maintenance and quality expenses and renewal investment is timely when the newly renewed unit's overall expenses are lower than the current unit expenses.

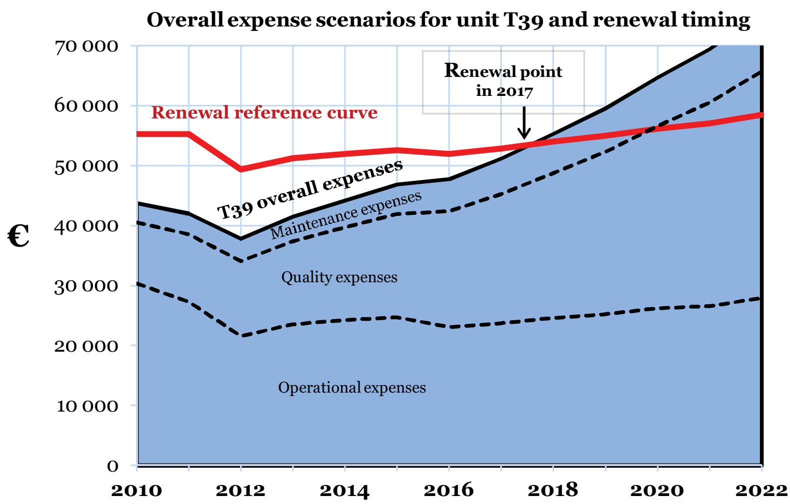


Figure 6-35 Overall expense development for unit T39 without renewal and with time-based maintenance. The red colored renewal reference curve illustrates overall annual expenses if the T39 unit would be renewed in that year.

Figure 6-35 presents the development of overall expenses for the current T39 unit with TMB maintenance and a reference curve for the unit renewal limit. Operational expenses vary with consumption and energy pricing, and there is no dramatic change with the current unit. The central reason for renewal is expected rising in the quality and maintenance expenses due to power transformer ageing. The renewal reference curve describes the overall annual expenses for the newly renewed unit and so when the overall expenses of the current unit rise the same level, it is time to renew. The assessment indicates that the current T39 unit with TBM maintenance should be renewed in the year 2017 in base scenario circumstances. After that point keeping the current unit in operation would gradually cost more due to reliability decrease and operational deficiency compared to the newly renewed unit.

Rise in quality expenses is the main reason for renewal. As in many cases, intensive maintenance can reduce the risks and slow down the process of expected overall expenses rising above renewed unit overall expenses. The maintenance intensity assessment presented in Chapter 6.4.2 for the T39 unit indicates the maintenance program shown in Table 6-6.

Table 6-6 Intensive maintenance program for ageing unit T39 to reduce risks and to postpone the renewal point. T=TBM, O=OLD, C=CBM

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
T39	T+O	T+O	T+C+O	T+C+O	T+C+O	T+C+O	T+C+O	T+C+O	T+C+O	T+C+O	T+C+O

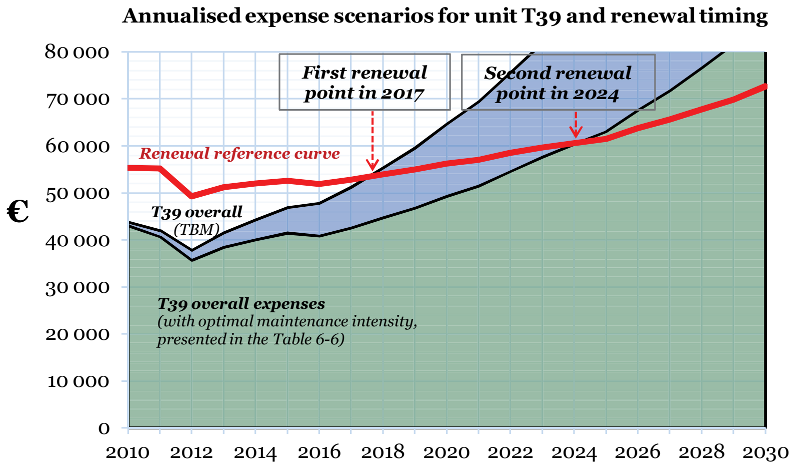


Figure 6-36 Renewal investment timing reference level with two maintenance intensity options. An assessment is made with base scenario values.

If the presented maintenance strategy is applied to unit T39, it would postpone the renewal time point for seven years in the base scenario environment compared to the situation when only time-based maintenance is applied. If the T39 unit is renewed in 2017, the unit's operational time would be 45 years and with a second renewal point, the operational time would rise to 52 years. The difference between the first and second renewal point options are in the shares of capital, operational, maintenance and quality expenses; when renewal is made at the earlier point, capital expenses rise and others decrease while in second renewal point option operational, maintenance and quality expenses are high.

The asset management balance between expenses changes as global economic situations develop. For example, changes in financial interest rates change the annualised capital expenses of a renewal investment. High interest rates increase capital expenses and thus the balanced renewal time are postponed, and vice versa with lower interest rates.

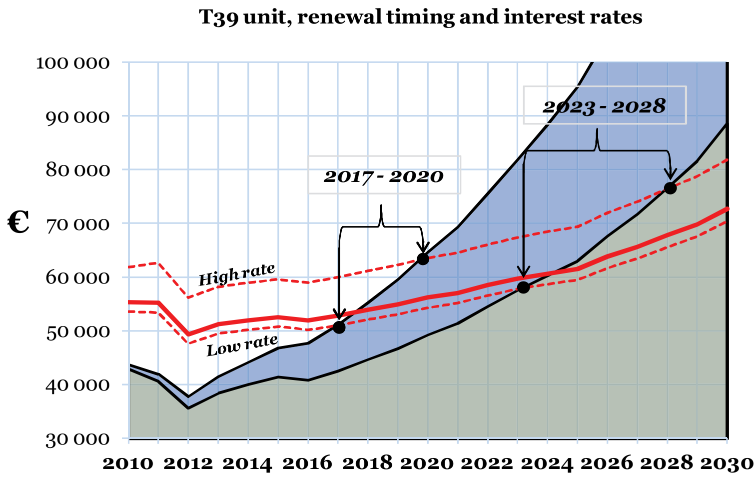


Figure 6-37 Real interest rate scenarios and effects on power transformer unit T39 renewal timing with changes in annualised renewal investment expense changes.

Global interest rates are currently at a relatively low level and when there is some relevant change in the interest rates it will be when interest rates increase. The applied real weighted average cost of capital scenarios presented in Table 4-2 results in a three to five year change in renewal timing in the case of the upper figure above. Basically, the same phenomena goes for changes in consumption, labour costs, energy prices and power transformer prices as well, but still there is the need to simplify any assessment to one conclusion. Currently it would be safer to choose the renewal point by comparing renewal option expenses to the current unit with normal time-based maintenance. This way the renewal time emphasises the known capital expenses over the other future expenses from operation, maintenance and quality, which are more volatile, especially when it comes to quality expenses. Annual operational expenses are also decreased with earlier investment scheduling.

The previous assessment is performed for every power transformer unit in the dynamic scenario modelling. Renewal points vary according to the condition and criticality of the unit. For example, the highly critical OFAF-cooled power transformer units T18 and T19 reach their renewal point six operational years earlier than the ONAF-cooled units T39 and T40, which are situated in an industrial suburban area. An illustration summarising the fleet renewal timing is constructed by subtracting overall expenses for renewed units in the same location from the overall expenses of the current unit in service. When the result is negative, it is time for the renewal investment in the given overall circumstances.

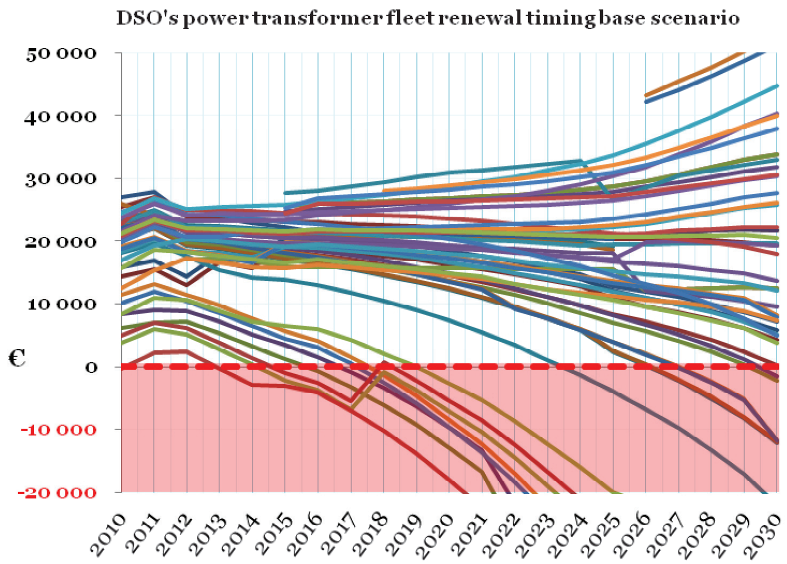


Figure 6-37 Renewal timing assessment for the entire power transformer fleet with the TBM maintenance intensity. The assessment is made using base scenario values. Detailed unit renewal years are listed in Appendix 8.1.

Every line represents a single power transformer and the more positive the values are, the better condition the unit is in. When the curve is approaching the zero value and gaining negative values the more beneficial it is to renew the unit in question. Seventeen power transformers will reach negative values in the period from 2013 to 2030. Detailed results for the renewal timing assessment are presented in Appendix 8.1.

6.5.2 Dynamic Capitalisation of Losses

The balance between capital and operational expenses depends on location, consumption development, energy prices, capacity expenses, TSO fees, characteristic consumption changes, commodity pricing and, especially, power transformer pricing. Location related design solutions such as special cooling systems also make a difference in loss capitalisation. An assessment is made for every unit with the different scenarios for energy pricing and consumption.

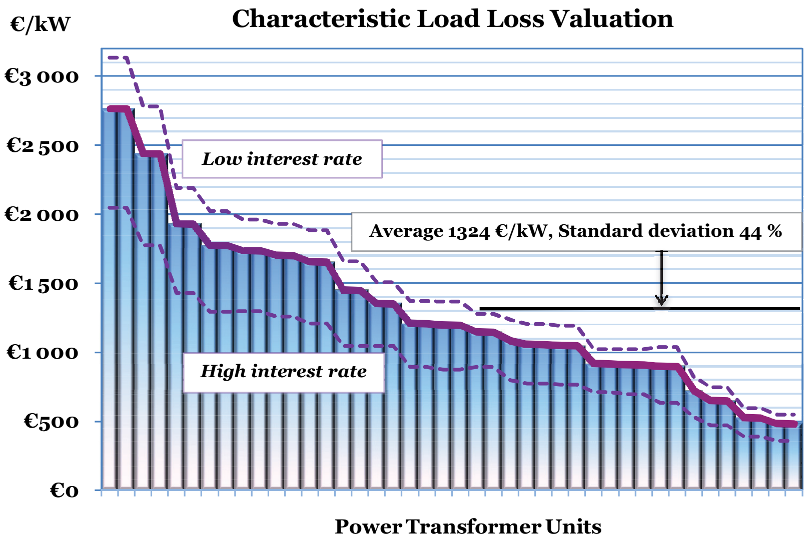


Figure 6-38 Capitalised losses for different units in the fleet with 40 year economic lifetime and base scenario values for consumption development and energy pricing.

Load loss valuation for different units can vary highly depending on expected consumption development and energy prices. The above figure presents load loss valuations for 42 different power transformer units. The average value for capitalised load losses are 1324 € per kilowatt, but there is high deviation of 44 percent between the values. The different scenarios for interest rates are also visible in the figure and when interest rate is high, future loss expenses become less relevant. With a low interest rate the opposite happens. The highest load loss valuation for the T47 unit with base scenario conditions is 2766 €/kW, because this unit has relatively high loading for many hours per day. The lowest load loss valuation is 485 €/kW for unit T61, which is located in a new substation, meaning that loading is relatively low for many years until the consumption increases around the new substation.

These variations clearly show why there are benefits in assessing load loss valuation near the purchase time, with different energy pricing, consumption development and interest rate scenarios.

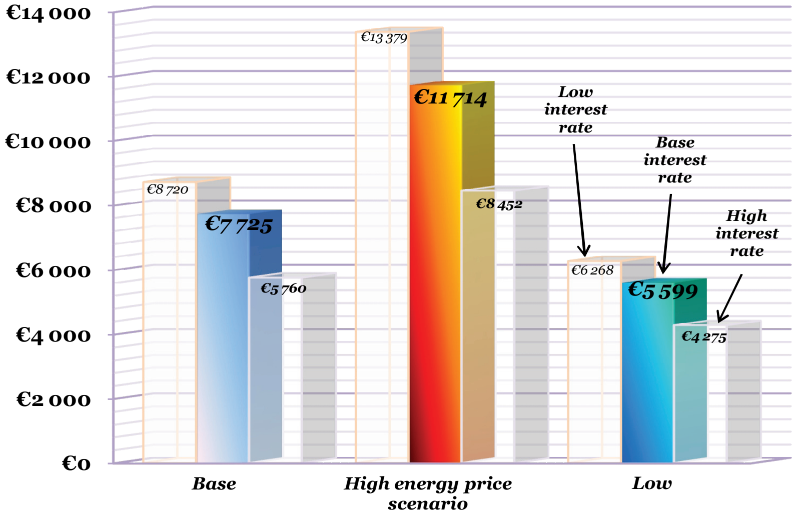


Figure 6-39 No-Load loss capitalisations with the different energy price scenarios and interest rates presented in Chapter 5.

No-load loss valuation does not vary between units; hence the loss energy profile is naturally the same, unless the unit is in abnormal, for example, as a reserve unit. Energy price scenarios and general interest rates dictate that the valuation of no-load losses and also economic lifetime differences will also have an effect. The no-load loss valuation is 7 725 €/kW with the base scenarios for energy pricing and interest rates. The lowest no-load loss valuation is 4 275 €/kW for the low energy price scenario when the high interest rate is applied. The highest valuation is 13 379 €/kW, when energy prices are high and interest rates are low. There is large variation and it is necessary to update loss valuation assessments with the most current information during power transformer purchase.

6.6 Discussion of the Assessment

Dynamic scenario assessment presents techno-economical dependencies taking different economic environments into consideration. Many distribution system elements have a long operational lifetime of over several decades and changes in the global economy can alter the asset manager's techno-economical balance in a much shorter period of time. Asset managers are not able to state one unambiguous conclusion that will be a guaranteed optimum over such a long period of time, but merely provide guidance though different possible paths according to the company strategy. Choosing the expected future economic environment development that should form the basis in decision-making is the task of the business core, and is therefore the responsibility of corporate management and ultimately the owners. This challenge remains the same, whether a simple single constant is used to evaluate future economic development or whether more detailed future economic scenario developments are applied. Continuous dynamic scenario modelling can still shorten the reaction time in asset management decision-making to different economic situations. The normally suggested frequency for updating economic environment scenarios in distribution system asset management is twice a year, based on the current global scenario updating by global financial institutions. In a turbulent economic environment, the scenario updating frequency should be naturally be increased.

Future research topics from this point might be to apply real option theory on top of the dynamic scenario modelling. Real option analysis could aid in narrowing down the distribution of the expected net present valuations in asset management. The dynamic scenario modelling could also be deepened towards macroeconomic theory. Economic environment scenario building could be enhanced by linking the interdependencies of economic attributes, such as the various material prices, construction activities and cost of labour.

7 Conclusions

Revealing the dynamics of power transformer asset management with scenarios is relevant in a turbulent global environment. The thesis has presented a method to assess techno-economical dependencies in the electricity distribution system to aid asset management decision-making.

Dynamic scenario modelling reveals the dependencies between the global economic situation and electrical distribution system asset management. Economic transients and even slower changes proportionally alter the overall balance in network asset management from a technical asset manager's point of view. The benefits of revealing asset dynamics with scenario modelling can be used for many purposes, depending on the owner's interests. It may be used to increase the quality of supply, to decrease capital expenses, and to minimise operational and maintenance expenses. Nevertheless, it is a tool that links investments, maintenance, operational expenses and quality aspects to the overall assessment of any given economic environment scenario.

Figure 7-1 Dynamic scenario modelling reveals the dependencies between global and local economics, and the asset management overall expenses of capital, operational, maintenance and quality.

Deterministic rules of thumb can lead to operational success when a substantial and sufficient amount of capital is guaranteed, even without a quantitative understanding of the overall balance between spending and expected performance. Dynamic scenario modelling gives the asset manager the possibility to make strategically transparent decisions regarding spending and quality within a changing environment. The comprehensive associated expenses in asset management with different scenarios are relevant to analyse and to quantitatively link with the technical and economic factors. Of course, a dynamic scenario model includes many uncertainties, but it is better to analyse possible scenarios beforehand than to analyse future economics with the expectation that price levels will stay the same. Dynamic scenario modelling is intended to evaluate the future environment in asset management, and so there is the need to update the scenario data and dynamics at least annually.

As a case example, dynamic scenario modelling was applied to a DSO's power transformer assets and, as a result, a balanced asset management plan was introduced. The presented result takes global economic prospects and technical power transformer factors into account in the same assessment. The case for a power transformer major overhaul was analysed taking into account the sensitivities to central economic and technical attributes. This analysis revealed new information for asset management decision-making concerning power transformer assets. A dynamic risk matrix was also introduced to enhance asset management long-term planning with scenario views. These are examples of what dynamic scenario modelling can achieve, but there are more possibilities from utilising this method. Basically, this approach could be applied to any distribution system asset with any given economic environment scenario, by modelling the asset specific dynamics, as was illustrated in Chapter five for power transformer assets.

A systematic approach increases the accuracy of asset management, and can be used at many levels of asset management. Corporate level quality targets can be quantitatively linked to overall economics and to asset portfolio management. Maintenance can be planned more accurately, so that actions are taken at the most optimal time, taking into account changes in the asset management environment. The chosen scenarios reflect the possible asset management environments for the distribution system operator and dynamic modelling enables the overall assessment of different asset management plans. There are several future application areas for dynamic scenario modelling in electricity distribution system asset management:

- **DSO's strategic long-term planning**
- **Asset portfolio management**
- **Asset investment, renewal and maintenance planning**

Current network information systems include the main information needed for dynamic scenario assessment. Operationally, electrical system analysis is highly automated and in daily usage. Integrating dynamic scenario modelling in electricity distribution system asset management would require the possibility to feed different scenarios for the economic environment in the time dimension as, currently, asset management economic environmental development factors are described with a single constant value or stable growth rate. One of the recent developments seen in practice due to the financial crisis, is the increased interest by capital investors in owning DSO business. In these circumstances, dynamic scenario modelling offers a tool to interpret technical asset management in terms of finance and vice versa, from financial parameterisation to technical asset performance.

Understanding the dynamic balance between asset management and overall expenses is becoming increasingly important, while seeking economic efficiency and return on investments.

REFERENCES

1. Hallberg Per, ***Europe's 2020 Electricity Grid: The Challenges of Reinventing the Grid to Meet the Needs of 2020 and Beyond***, Eurelectric Smart Grid Chairman presentation in Finnish Energy Industries R&D seminar 1.10.2009 in Helsinki, Downloaded on 12.10.2009 http://www.energia.fi/fi/sahko/sahkoverkko/st-pooli/seminaarit/2009

2. OECD Discussion Paper (Organisation for Economic Co-operation and Development), ***Green Growth: Overcoming the Crisis and Beyond***, downloaded 29.06.2009 from OECD 2009. http://www.oecd.org/dataoecd/4/40/43176103.pdf

3. Kotler Philip, Caslione John A., ***Chaotics: The Business of Managing and Marketing in The Age of Turbulence***, Amacom 2009.

4. Palola Jussi, Hyvärinen Markku, Haveri Petteri, Lehtonen Matti, ***Investment Portfolio Tool Specification for an Electrical Network Asset Manager***, 9th International Conference on Probabilistic Methods Applied to Power Systems, KTH Stockholm, Sweden – June 2006.

5. McCloskey D. N., ***The Rhetoric of Economics***, The University of Iowa, Journal of Economic Literature Vol. XXI, June, 481-517, 1983.

6. ***Electricity Market Act* 386/1995; amendments up to 1172/2004 included**, Ministry of Trade and Industry, Finland 2004.

7. The Finnish Energy Market Authority, ***Annual Report 2008***, Downloaded 12.11.2009. http://www.emvi.fi/files/Annual_report_2008.pdf

8. Edgar E. P., ***Fractal Market Analysis, Applying Chaos Theory to Investment and Economics***, Printed in the United States of America, John Wiley & Sons inc. 1994.

9. Willis H. Lee, ***Power Distribution Planning Reference Book***, second edition – revised and expanded, Marcel Dekker Inc., New York 2004.

10. Yingxu Wang, Dong Liu, Guenther Ruhe, ***Formal Description of The Cognitive Process of Decision Making***, University of Calgary, IEEE International Conference on Cognitive Informatics ICCI, 2004

11. Anders G. J., Endrenyi J., Yung C., ***Risk-Based Planner for Asset Management***, IEEE Computer Applications in Power, 20-26, IEEE 2001.

12. Honkapuro Samuli, ***Performance Benchmarking and Incentive Regulation – Considerations of Directing Signals for Electricity Distribution Companies***, Doctoral Dissertation, Lappeenranta University of Technology, 2008.

13. Yin Robert K., ***Case Study Research: Design and Methods***, Fourth Edition, Applied Social Research Methods Series Volume 5, SAGE Publications 2009.

14. Arbnor Ingeman, Bjerke Bjrön, ***Methodology for Creating Business Knowledge***, Third Edition, SAGE Publications 2009.

15. Brown Richard E., Humbrey Bruce G., ***Asset Management for Transmission and Distribution – Balancing Performance, Cost and Risk***, Power & Energy Society, May/June, 39-45, IEEE 2005.

16. Allan Ron, Billington Roy, ***Probabilistic Assessment of Power Systems***, Proceedings of the IEEE, VOL. 88, NO. 2, 140-162, February 2000.

17. Rimell John, ***The Importance of Asset Data to Support an effective Asset Management Policy***, The Institution of Electrical Engineers, printed and published by the IEE, London, UK 1999.

18. Balzer G., Neumann C., Gaul A., Schorn C., ***The General Asset Management Process of Power Systems***, Cigre publication 212, Osaka 2007.

19. OECD/IEA, International Energy Agency, ***Electricity Information 2008,*** IEA Publications, Printed in France by STEDI, August 2008.

20. Eranti Esa, ***Sustainable Development or the Will to Power? The European Union and Finland Pursuing Environmental Policy,*** 108-110, Helsinki University of Technology 2008.

21. Balzer G., Asgarieh L., Neumann C., Gaul A., Bakic K., Schorn C., ***Planning of Long Term Transmission Investment of Power Systems***, Cigre publication C1-113, Paris 2008.

22. Sheng Su, Li K. K., Chan W.L., Zeng X. J., Xianzhong Duan, ***A Practical Circuit Breaker Monitoring System***, Changsha University of Science and Technology, The HongKong Polytenic University, Huazhong University of Science and Technology, 867-872, IEEE 2005.

23. The IEEE Standards Committee on Power Switchgear C37 reaffirmed 2008, ***IEEE Guide for Diagnostics and Failure Investigation of Power Circuit Breakers***, Switchgear Committee of the IEEE Power & Engineering Society 2008.

24. Endrenyi J., Anders G., ***Aging, Maintenance and Reliability: Approaches to Preserving Equipment Health and Extending Equipment Life***, Power & Energy Society, May/June, 59-67, IEEE 2006.

25. Martin A., Bamford P., ***Improving Business Performance Through Risk Based Asset Management***, International Conference on Railway Engineering - Challenges for Railway Transportation in Information Age, ICRE 2008.

26. Lehtonen Matti, ***On the Optimal Strategies of Condition Monitoring and Maintenance Allocation in Distribution Systems***, 9th International Conference on Probabilistic Methods Applied to Power Systems, KTH Stockholm, Sweden June 2006.

27. Santala Mika, ***Life Assessment: Ranking of Aged GSU and Industry Transformers from a Technical Point of View***, written in Finnish, Master of Science Thesis, Lappeenranta University of Technology, Vaasa, Finland 1999.

28. Lee Amanda, Brhanavan Jude, Lewis Michael, Willis Tama, MacKinnon John, Sieminski Adam, Crane Joel, ***Global Market Research: Commondities Quartely***, Deutsche Bank, September, 2007.

29. Shahid Alam M., ***A Short History of the Global Economy Since 1800***, Northeastern University, Boston, MPRA Paper No. 1263, June 2003.

30. European Central Bank, ***The Monetary Policy of The European Central Bank 2011***, 7-12, ECB 2011.

31. Samper Mauricio E., Vargas Alberto, ***Investment Decisions in Distribution Networks Under Uncertainty With Distributed Generation —Part I: Model Formulation***, Transactions on Power Systems, 1-10, IEEE 2013.

32. Heathcote Martin J., ***The J & P Transformer Book: A Practical Technology of the Power Transformer***, 12th edition, Newnes, Elsevier Science Ltd., Oxford 2003.

33. Schijndel Arjan, Wetzer Jos M., Wouters P.A.A.F., ***Forecasting Transformer Reliability***, 2006 Annual Report Conference on Electrical Insulation and Dielectric Phenomena, 577-582, IEEE 2006.

34. The London Metal Exchange Limited, ***London Metals Exchange Market Data, The Centre for Non-Ferrous Metal Trading***, London, UK http://www.lme.com

35. CIGRE working group 12.09, ***Thermal Aspects of Transformers – Aspect Thermiques des Transformateurs***, working group report, August 1995.

36. Silvast Antti, Heine Pirjo, Lehtonen Matti, Kivikko Kimmo, Mäkinen Antti, Järventausta Pertti, ***Cost of Interruption for The Electricity Network Customers in Finland***, (in Finnish) Helsinki and Tampere Universities of Technology, December 2005.

37. The Research Institute of the Finnish Economy – ETLA, ***World Commodity Prices 2009-2010***, in Finnish: "Raaka-aineiden maailmanmarkkinahinnat v. 2009-2010", Print 84, May 2009.

38. Doman Linda, ***International Energy Outlook May 2007: Electricity Chapter***, Energy Information Administration, Office of Integrated Analysis and Forecasting, U.S. Department of Energy, Washington, DC 2007.

39. Publicly Available Specification (PAS), ***PAS 55-1:2008 Asset Management: Part 1: Specification for the Optimized Management of Physical Assets***, British Standards September 2008.

40. Publicly Available Specification (PAS), ***PAS 55-2:2008 Asset Management: Part 2: Guidelines for the Application of PAS 55-1***, British Standards September 2008.

41. Taylor Frederick Winslow, ***The Principles of the Scientific Management***, Harper & Brothers Publishers, New York and London 1911, Replica edition by Elibron Classics, Adamant Media Corporation 2005.

42. Haddad Gilbert, Sandborn Peter, Pecht Michael, ***Using Real Options to Manage Condition-Based Maintenance Enabled by PHM***, Center for Advanced Life Cycle Engineering, Department of Mechanical Engineering University of Maryland, 1-7, IEEE 2011.

43. Kronström Kai et al., ***Electric Vehicles in Finland – Investigation***, ordered by The Finnish Ministry of Employment and the Economy, written in finnish: "Sähköajoneuvot Suomessa – selvitys", August, Finland 2009.

44. Cobb Barry R., Charnes John M., ***Real Options Valuation***, Proceedings of the 2007 Winter Simulation Conference, 173-182, IEEE 2007.

45. Energy Market Authority of Finland, ***Regulation Methods for the Assessment of Reasonableness in Pricing of Electricity Distribution Network Operations and High-voltage Distribution Network Operations in the Third Regulatory Period Starting on 1st of January 2012 and Ending on 31st of December 2015***, Finland 2011.

46. European Commission – Eurostat, ***European Statistics for All-items Harmonised Index of Consumer Prices in the European Union 1997-2013***, Eurostat ID: prc_hicp_manr, referred 9.7.2013, Access method: http://epp.eurostat.ec.europa.eu/portal/page/portal/eurostat/home/

47. Schwan Michael, Schilling Klaus, Zickler Uwe, Schnettler Armin, ***Component Reliability Prognosis in Asset Management Methods***, 9th International Conference on Probabilistic Methods Applied to Power Systems KTH, Stockholm, Sweden – June 11-15, 2006.

48. Koponen Pekka, VTT Technical Research Centre of Finland, Joel Seppälä, Helen Electricity Network Ltd, ***Comparison of Price Control Methods for Electrical Heating, Simulation Study***, 14-15, Finland 2010.

49. CIRED Working Group on Smart Grid, ***Smart Grids on the Distribution Level – Hype or Vision?*** CIRED's Point of View, Report 18.3.2013.

50. Jongen Rogier, Morshuis Peter, Smit Johan, Janssen Anton, Gulski Edward, ***A Statistical Approach to Processing power Transformer Failure***, CIRED 19th International Conference on Electricity Distribution, Vienna, May 2007.

51. Bossi A., Dind J.E., Frisson J.M., Khoudiakov U., Light H.F., Narke D.V., Tournier Y., Verdon J., ***An International Survey of Failures in Large Power Transformers in Service***, Final Report of the CIGRE Working Group 12.05, Electra, No. 88, 21-48, 1983.

52. International Electrotechnical Comission IEC International Standard, ***Power Transformers: Part 7: Loading Guide for Oil-immersed Power Transformers***, IEC 60076-7 Edition 1.0, Geneva, Switzerland 2005.

53. Lundgaard Lars E., Hansen Walter, Linhjell Dag, Painter Terence J., ***Aging of Oil-Impregnated Paper in Power Transformers***, IEEE Transactions on Power Delivery, Vol. 19 No. 1, 230-239, January 2004.

54. Allan D. M., ***A Practical Life Assessment Technique for Aged Oil Paper Systems***, Queensland Electricity Commission Australia, Sixth International Conference on Dielectric Materials, Measurements and Applications, 221-224, Manchester 1992.

55. Bérubé Jean-Noël, Aubin Jacques, McDermid W., ***Transformer Winding Hot Spot Temperature Determination***, Neoptix Inc. – Manitoba Hydro, Electric Energy Online Magazine, Downloaded on 28.2.2010 from http://www.electricenergyonline.com/?page=show_article&mag=41&article=311

56. Reddy Ankireddypalli S., Vijaykumar M., ***Hottest Spot and Life Evaluation of Power Transformer Design Using Finite Element Method***, JNT University India, Journal of Theoretical and Applied Information Technology, 238-243, 2008.

57. Institute of Electrical and Electronics Engineers, ***IEEE Database Xplore – Advanced Searching Tool*** http://ieeexplore.ieee.org.libproxy.tkk.fi/Xplore/dynhome.jsp

58. Bush Rick, Stiegemeier Craig, Cobb Geoff, Woodcock David, ***When Will Your Transformer Die?***, Transmission & Distribution World Web Seminar Presentation, June 21, 2007.

59. CIGRE Working Group A2.20, ***Guide on Economics of Transformer Management***, June 2004.

60. IBM Global Business Services, ***The Evolution of Asset Management - Finding the Right Best Practice is Not All Theory***, United States of America, 2007.

61. Sparling Brian D., Aubin Jacques, ***Power Transformer Life Extension Through Better Monitoring***, GE Energy Hydran Product Study in Power-Grid Europe Conference, Spain, 2007.

62. Baehr R., ***Trasnformer Technology State-of-the Art and Trends of Future Development***, No. 198 – October, Electra, 13-19, 2001.

63. Kivikko Kimmo, Järventausta Pentti, Mäkinen Antti, Silvast Antti, Heine Pirjo, Lehtonen Matti, ***Research and Analysis Method Comparison in Finnish Reliability Worth Study***, CIRED 19th International Conference on Electricity Distribution paper 0542, Vienna 2007.

64. Rausand Marvin, Høyland Arnljot, ***System Reliability Theory – Models, Statistical Methods and Applications***, John Wiley & Sons, Inc, 2nd edition, 2004.

65. Blanc R., Buffiere G., Taisne J-P., Tanguy A., Guuinic P., Long P., Moutin E., Devaux F., ***Transformer Refurbishment Policy at RTE Conditioned by the Residual Lifetime Assessment***, A2-204, Cigre 2008.

66. Economy Watch, ***Economy, Investments & Finance Report, Commodities Price Statistics***, downloaded on 9.11.2010. http://www.economywatch.com/economic-statistics /price-index-indicators/

67. The World Bank, The International Bank for Reconstruction and Development, ***Global Economic Prospects: Commodities at the Crossroads***, The World Bank, Washington, USA 2009. Prospects updated from ***Global Economic Prospects June 2012 and June 2013: Prospects for Commodity Markets***.

68. Koreneff Göran, Ruska Maija, Kiviluoma Juha, Shemeikka Jari, Lemström Bettina, Alanen Raili, Koljonen Tiina, **Future Development Trends in Electricity Demand**, Research Notes 2470, VTT Technical Research Centre of Finland, Espoo 2009.

69. Jalovaara Veli-Matti, Laatikainen Tuula, Laitala Marko, Leino Raili, Lukkari Jukka, Pihlava Minna, Raunio Helena, Repo Harri, Törmänen Eeva, ***Finnish Industry Growth in Fluctuation,*** Report in Finnish: "Teollisuus nousuun vaihtelevasti", Tekniikka & Talous Survey 14.1.2011.

70. Commission of The European Communities, ***Communication from The Commission, Action Plan for Energy Efficiency: Realising the Potential***, COM(2006) 545 final, Brussels 2006.

71. Finland Ministry of Economy and Employment, ***Long-term Climate and Energy Strategy,*** in Finnish: "Pitkän aikavälin ilmasto- ja energiastrategia", Government Report to Parliament, 6 November 2008.

72. Tenbohlen S., Stirl T., Bastos G., Baldauf J., Mayer P., Stach M., Breitenbauch B., Huber R., ***Experienced-based Evaluation of Economic Benefits of On-line Monitoring Systems for Power Transformers***, CIGRE 12-110, session 2002.

73. Ruska Maija, Kiviluoma Juha, Koreneff Göran, ***Scenarios of Large-scale Deployment of Electric Vehicles and Their Power System Impacts***, in Finnish: "Sähköautojen laajan käyttöönoton skenaarioita ja vaikutuksia sähköjärjestelmään", VTT Technical Research Centre of Finland, 2010.

74. Hyvärinen Markku, ***Electrical Networks and Economies of Load Density***, Doctoral dissertation, Department of Electrical Engineering, Helsinki University of Technology, Espoo, Finland 2008.

75. Hyvärinen Markku, ***Spatio-Temporal Load Forecasting***, Spatial Load Forecasting Post Graduate Seminar Report, Helsinki University of Technology, 2006.

76. Finnish Business and Policy Forum EVA, Capful , ***EVA's Global Scenarios - Playing Fields of the Future***, Helsinki, Finland 2009. http://www.eva.fi/julkaisut/english-global-scenarios-2/1563/

77. Wigren Rune, Wilhelmsson Mats, ***Construction Investments and Economic Growth in Western Europe***, Journal of Policy Modeling, 2006.

78. World Steel Association, ***Fact Sheet: Steel and Raw Materials***, May 2011. Access method: http://www.worldsteel.org/publications/fact-sheets.html

79. Ernst & Young's Global Mining & Metals Center, ***Global Steel — 2011 Trends 2012 Outlook, Competing for Growth in the Steel Sector***, 2012. Access method: http://www.ey.com/Publication/vwLUAssets/Global_steel_2011_trends_2012_outlook/$FILE/Global_Steel_Jan_2012.pdf

80. Government of Canada, Natural Resources Canada, ***Long Term Outlook: Crude Oil Prices to 2030***, October 2010. Access method: http://www.nrcan.gc.ca/energy/publications/sources/crude/issues-prices/1329, Downloaded 30.7.2012.

81. Taleb Nassim Nicholas, ***The Black Swan: The Impact of the Highly Improbable***, Penguin Books Ltd, revised edition 2010.

82. Maluf David A., Gawdiak Yuri O., National Aeronautics and Space Administration, Bell David G., Research Institute for Advanced Computer Science, ***On Space Exploration and Human Error: A Paper on Reliability and Safety***, HICSS Proceedings of the Proceedings of the 38th Annual Hawaii International Conference on System Sciences, Track 3, Volume 3, IEEE Computer Society Washington, DC, USA 2005.

83. Maijala Aino, ***The Life Cycle Cost Study for the Pavement Alternatives of Road Traffic Routes***, (in Finnish), Helsinki University of Technology Construction Economics and Management Papers 55, Ramboll Finland Oy, Espoo 2005.

84. Siefert William T., Boeing Company, Smith Eric D., University of Texas, ***Cognitive Biases in Engineering Decision Making***, 1-10, IEEE 2011.

85. Donnell Michael L., Lehner Paul E., ***Uncertainty Handling and Cognitive Biases in Knowledge Engineering***, Transactions on Systems, Man, and Cybernetics, vol. 23, no. 2, 563-570, IEEE 1993.

86. Schoemaker Paul J. H., ***Scenario Planning: A Tool for Strategic Thinking***, The Wharton School, University of Pennsylvania, Sloan Management Review Winter, 25-40, 1995.

87. Takala Otso, ***Maintenance Effects on 110-400 kV Power Transformer's Reliability in Finland***, Customer Survey Report, (in Finnish), Fortum Service 2005.

88. Bank of Finland, ***Euro & Economy: Economic Prospects 5/12***, in Finnish: Euro & Talous: Talouden näkymät, December 2012.

89. Official Statistics of Finland (OSF): ***Building Cost Index and Construction Activity***, e-publication, Helsinki: Statistics Finland, Access method: http://www.stat.fi/til/rki/index_en.html.

90. OECD Statistics, ***Consumer Price Indices, Unit Labour Costs and Labour Productivity for Construction Industry, Manufacturing Industry and Total Economy***, Organisation for Economic Co-operation and Development, referred 31.7.2012, Access method: http://stats.oecd.org/.

91. Official Statistics of Finland (OSF), ***Labour Cost Index*** e-publication, Helsinki: Statistics Finland, referred: 12.7.2012, Access method: http://www.stat.fi/til /tvki/index_en.html.

92. Economy Watch Statistics Database Service, ***Indices for Commodity Prices: Oil, Iron and Copper***, July, Economy Watch 2012. Access method http://www.economywatch.com/economic-statistics/price-index-indicators/

93. Myötyri E., Pulkkinen Urho, Simola K., ***Application of Stochastic Filtering for Lifetime Prediction***, Technical Research Centre of Finland, Reliability Engineering and System Safety 91, Science Direct, Finland 2003.

94. Susa Dejan, Palola Jussi, Lehtonen Matti, Hyvärinen Markku, ***Temperature Rises in an OFAF Transformer at OFAN Cooling Mode in Service***, Transactions on Power Delivery, Vol. 20, nro 4, 2517-2525, IEEE 2005.

95. Virtanen Seppo, ***Failure Rate Function for Reliability Assessment***, in Finnish: "Vikataajuusfunktion käyttö vika-taipumuksen arvioinnissa", Course KSU-4310 Material of Tampere University of Technology, Introduction to Reliability Engineering and Maintenance.

APPENDIX 1

Example DSO´s current power transformer fleet information

	Manufacturing (year)	Rated Power (MVA)	Cooling system	Nominal no load losses (kW)	Nominal load losses (kW)	Residential	Commercial	Public	Industrial
T10	1990	31,5	OFAF	15	167	28 %	47 %	12 %	13 %
T11	1990	31,5	OFAF	16	173	28 %	47 %	12 %	13 %
T12	1971	30	OFAF	23	138	14 %	66 %	18 %	3 %
T13	1971	30	OFAF	23	138	14 %	66 %	18 %	3 %
T14	1986	40	OFAF	15	177	17 %	46 %	19 %	17 %
T15	1986	40	OFAF	15	176	17 %	46 %	19 %	17 %
T16	2003	31,5	OFAF	14	120	14 %	60 %	23 %	4 %
T17	2007	31,5	OFAF	21	115	14 %	60 %	23 %	4 %
T18	1976	31,5	OFAF	21	158	10 %	71 %	16 %	3 %
T19	1977	31,5	OFAF	21	151	10 %	71 %	16 %	3 %
T20	2005	31,5	ONAF	17	141	26 %	36 %	30 %	9 %
T21	2005	31,5	ONAF	17	148	26 %	36 %	30 %	9 %
T22	1987	31,5	ONAF	17	129	26 %	36 %	30 %	9 %
T23	1989	31,5	OFAF	16	148	10 %	35 %	38 %	17 %
T24	1988	31,5	OFAF	16	148	10 %	35 %	38 %	17 %
T25	1986	31,5	OFAF	17	151	24 %	25 %	50 %	1 %
T26	1981	31,5	OFAF	21	154	24 %	25 %	50 %	1 %
T27	1985	31,5	OFAF	15	161	26 %	43 %	30 %	1 %
T28	1985	31,5	OFAF	15	161	26 %	43 %	30 %	1 %
T29	2013	31,5	OFAF	20	131	38 %	37 %	12 %	13 %
T30	2013	31,5	OFAF	20	131	38 %	37 %	12 %	13 %
T35	2011	40	OFWF	20	133	14 %	66 %	18 %	3 %
T36	2011	40	OFWF	20	133	14 %	66 %	18 %	3 %
T37	1992	31,5	OFAF	18	139	62 %	15 %	20 %	3 %
T38	1992	31,5	OFAF	18	139	62 %	15 %	20 %	3 %
T39	1972	40	ONAF	25	192	35 %	25 %	17 %	24 %
T40	1972	40	ONAF	24	216	35 %	25 %	17 %	24 %
T41	1976	40	ONAF	30	208	48 %	32 %	17 %	4 %
T42	1976	40	ONAF	31	208	48 %	32 %	17 %	4 %
T43	1990	40	ONAF	23	164	52 %	17 %	17 %	15 %
T44	1990	40	ONAF	21	164	52 %	17 %	17 %	15 %
T45	2000	40	OFAF	20	150	12 %	43 %	37 %	8 %
T46	2000	40	OFAF	21	150	12 %	43 %	37 %	8 %
T47	1975	40	ONAF	27	220	33 %	14 %	47 %	5 %
T48	1980	40	ONAF	31	176	33 %	14 %	47 %	5 %
T49	1982	31,5	ONAF	20	132	33 %	14 %	47 %	5 %
T50	2001	40	ONAF	24	168	31 %	29 %	23 %	17 %
T51	2001	40	ONAF	24	208	31 %	29 %	23 %	17 %
T52	1982	31,5	ONAF	20	132	10 %	39 %	11 %	40 %
T53	1987	40	ONAF	16	204	10 %	39 %	11 %	40 %
T54	1980	40	ONAF	30	176	54 %	22 %	14 %	10 %
T55	2004	40	ONAF	21	180	54 %	22 %	14 %	10 %
T56	1984	40	OFAF	19	192	64 %	19 %	11 %	6 %
T57	1984	40	OFAF	19	192	64 %	19 %	11 %	6 %
T58	1991	40	OFAF	24	164	64 %	19 %	11 %	6 %
T59	1995	40	ONAF	23	168	56 %	16 %	14 %	14 %
T60	1995	40	ONAF	22	168	56 %	16 %	14 %	14 %
T61	2009	40	ONAF	20	142	64 %	19 %	11 %	6 %
T62	2009	40	ONAF	20	142	64 %	19 %	11 %	6 %

APPENDIX 2

Planned Power Transformer Fleet Information

	Purchase (year)	Rated Power (MVA)	Cooling system	Estimated nominal no load losses (kW)	Nominal load losses (kW)	Residential	Commercial	Public	Industrial
T31	2014	30	OFAF	18	121	26 %	36 %	30 %	9 %
T32	2026	31,5	OFAF	13	106	26 %	36 %	30 %	9 %
T33	2025	31,5	OFAF	13	108	26 %	36 %	30 %	9 %
T34	2025	31,5	OFAF	13	108	26 %	36 %	30 %	9 %
T63	2017	40	ONAF	16	128	52 %	17 %	17 %	15 %
T64	2015	40	OFAF	17	132	12 %	43 %	37 %	8 %
T65	2015	40	OFAF	17	132	12 %	43 %	37 %	8 %

APPENDIX 3

Example Power Transformer Asset Management Plan

UNIT INFORMATION			RENEVAL TIME		MAINTENANCE INTENSITY					
	Manufac-turing (year)	Cooling system	Reneval / planned reneval (year)	Planned Reneval age	TBM	CBM	Major overhaul or not	Online diagnos-tics	Major overhaul year	OLD instal-lation year
T10	1990	OFAF	2030	40	X		X		2012	
T11	1990	OFAF	2030	40	X		X		2012	
T12	1971	OFAF	2010	39	X		X	X	1996	2007
T13	1971	OFAF	2010	39	X		X	X	1996	2007
T14	1986	OFAF	2026	40	X		X		2008	
T15	1986	OFAF	2026	40	X		X		2008	
T16	2003	OFAF	2043	40	X		X		2023	
T17	2007	OFAF	2047	40	X		X		2027	
T18	1976	OFAF	2016	40	X		X	X	2002	2012
T19	1977	OFAF	2016	39	X		X	X	2002	2012
T20	2005	ONAF	2045	40	X		X	X	2030	2005
T21	2005	ONAF	2045	40	X		X	X	2030	2005
T22	1987	ONAF	2027	40	X		X		2010	
T23	1989	OFAF	2029	40	X		X		2009	
T24	1988	OFAF	2029	41	X		X		2009	
T25	1986	OFAF	2026	40	X		X		2006	
T26	1981	OFAF	2021	40	X		X		2006	
T27	1985	OFAF	2025	40	X		X		2007	
T28	1985	OFAF	2025	40	X		X		2007	
T29	2013	OFAF	2053	40	X		X		2038	
T30	2013	OFAF	2053	40	X		X		2038	
T31	2014	OFAF	2054	40	X		X		2039	
T32	2026	OFAF	2066	40	X		X		2051	
T33	2025	OFAF	2065	40	X		X		2050	
T34	2025	OFAF	2065	40	X		X		2050	
T35	2011	OFWF	2051	40	X		X	X	2036	2011
T36	2011	OFWF	2051	40	X		X	X	2036	2012
T37	1992	OFAF	2032	40	X		X		2015	
T38	1992	OFAF	2032	40	X		X		2015	
T39	1972	ONAF	2014	42	X		X	X	1993	2012
T40	1972	ONAF	2014	42	X		X	X	1994	2012
T41	1976	ONAF	2016	40	X			X	0	2010
T42	1976	ONAF	2016	40	X			X	0	2010
T43	1990	ONAF	2030	40	X		X		2015	
T44	1990	ONAF	2030	40	X		X		2015	
T45	2000	OFAF	2040	40	X		X	X	2020	2012
T46	2000	OFAF	2040	40	X		X	X	2020	2012
T47	1975	ONAF	2015	40	X		X		2004	
T48	1980	ONAF	2020	40	X		X		2003	
T49	1982	ONAF	2022	40	X		X		2000	
T50	2001	ONAF	2041	40	X		X		2024	
T51	2001	ONAF	2041	40	X		X		2024	
T52	1982	ONAF	2022	40	X		X		2000	
T53	1987	ONAF	2027	40	X		X		2010	
T54	1980	ONAF	2020	40	X		X		2003	
T55	2004	ONAF	2044	40	X		X		2027	
T56	1984	OFAF	2024	40	X		X		2005	
T57	1984	OFAF	2024	40	X		X	X	2005	2006
T58	1991	OFAF	2031	40	X		X		2013	
T59	1995	ONAF	2035	40	X		X		2018	
T60	1995	ONAF	2035	40	X		X		2018	
T61	2009	ONAF	2049	40	X		X		2033	
T62	2009	ONAF	2049	40	X		X		2033	
T63	2017	ONAF	2057	40	X		X		2040	
T64	2015	OFAF	2055	40	X		X		2039	
T65	2015	OFAF	2055	40	X		X		2039	

X = YES **"Empty" = NO**

APPENDIX 4

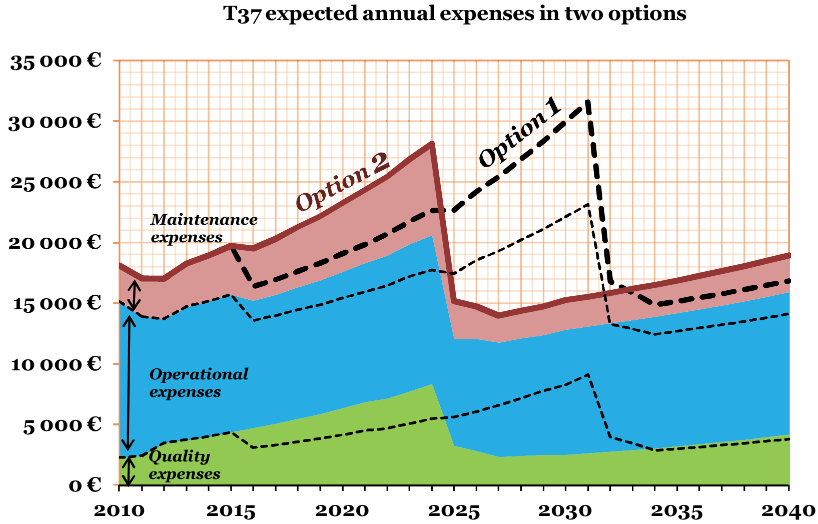
Price Scenario View 2013 Applied in the Scenario Analysis

Economic Scenarios Applied in the Analysis (in nominal prices)

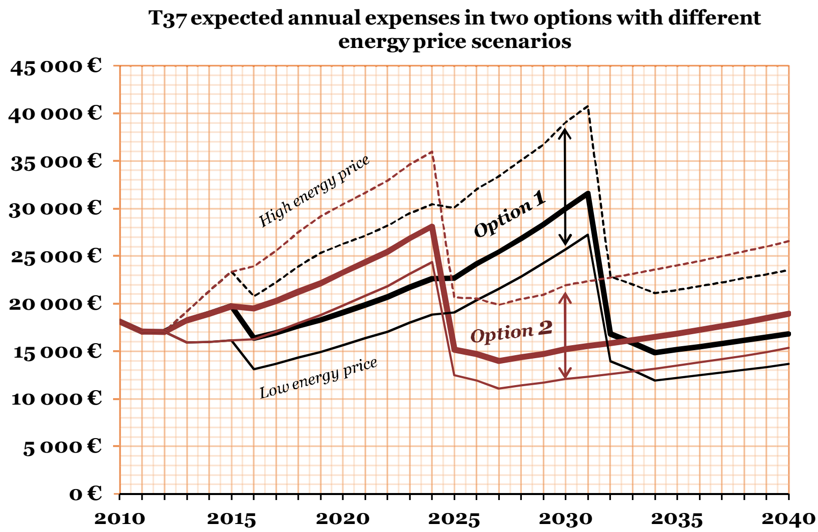
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
COPPER																					
Index																					
Base	1,00	1,17	1,06	0,98	0,97	0,96	0,95	0,94	0,94	0,93	0,93	0,92	0,92	0,91	0,91	0,90	0,95	0,99	1,04	1,08	1,13
High	1,00	1,17	1,06	1,04	1,08	1,11	1,16	1,15	1,15	1,14	1,13	1,13	1,12	1,11	1,11	1,10	1,16	1,21	1,27	1,32	1,38
Low	1,00	1,17	1,06	0,92	0,86	0,81	0,74	0,74	0,73	0,73	0,72	0,72	0,72	0,71	0,71	0,70	0,74	0,77	0,81	0,85	0,88
IRON																					
Index																					
Base	1,00	1,15	0,88	0,97	0,96	0,95	0,95	0,95	0,96	0,97	0,97	0,97	0,98	0,98	0,99	0,99	1,05	1,11	1,17	1,23	1,29
High	1,00	1,15	0,88	1,07	1,15	1,13	1,14	1,14	1,15	1,16	1,16	1,17	1,17	1,18	1,19	1,19	1,26	1,34	1,41	1,48	1,55
Low	1,00	1,15	0,88	0,88	0,77	0,76	0,76	0,76	0,77	0,77	0,77	0,78	0,78	0,79	0,79	0,79	0,84	0,89	0,94	0,99	1,03
OIL																					
Index																					
Base	1,00	1,32	1,33	1,30	1,28	1,28	1,28	1,27	1,27	1,27	1,27	1,27	1,28	1,28	1,29	1,29	1,30	1,31	1,31	1,32	1,33
High	1,00	1,32	1,33	1,39	1,43	1,48	1,55	1,63	1,63	1,62	1,62	1,63	1,63	1,64	1,65	1,65	1,66	1,67	1,68	1,69	1,70
Low	1,00	1,32	1,33	1,23	1,21	1,17	1,15	1,14	1,11	1,09	1,05	1,03	1,01	0,99	0,97	0,95	0,95	0,96	0,97	0,98	0,99
CONSTRUCTION																					
Index																					
Base	1,00	1,03	1,06	1,10	1,13	1,16	1,19	1,24	1,29	1,32	1,34	1,37	1,39	1,42	1,45	1,47	1,50	1,53	1,56	1,59	1,62
High	1,00	1,03	1,06	1,14	1,20	1,25	1,31	1,37	1,42	1,45	1,47	1,50	1,53	1,56	1,59	1,62	1,65	1,68	1,71	1,75	1,78
Low	1,00	1,03	1,06	1,07	1,07	1,07	1,07	1,12	1,16	1,18	1,21	1,23	1,25	1,28	1,30	1,33	1,35	1,38	1,40	1,43	1,46
ENERGY																					
€/MWh																					
Base	57	49	37	39	40	39	36	36	36	37	38	38	40	41	41	41	43	44	46	46	49
High	57	49	37	43	50	55	54	58	62	66	67	68	72	74	74	73	77	79	81	83	89
Low	57	49	37	29	27	24	22	22	23	23	23	24	25	26	26	26	27	27	28	29	31

APPENDIX 5

Major overhaul analysis results for unit T37

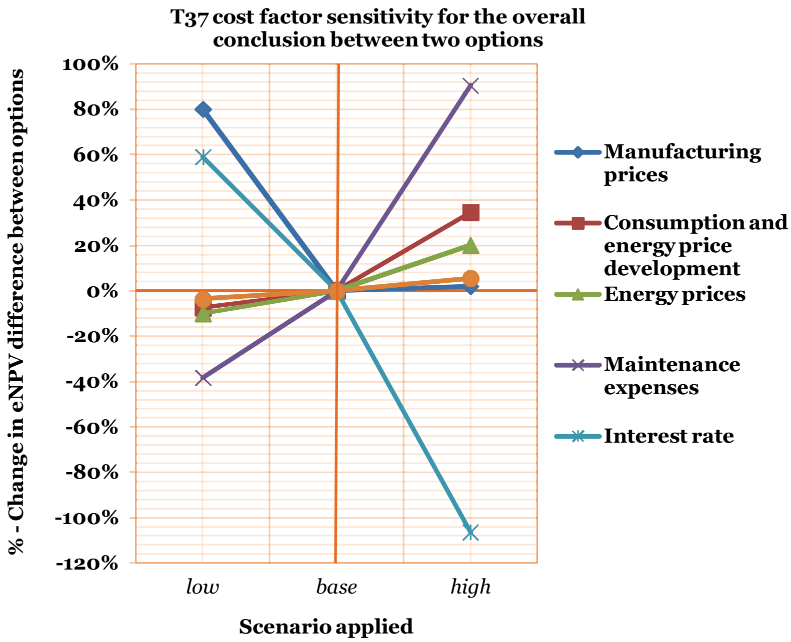


Appendix Figure 5-1 **Expected annual expenses for power transformer T37 in two different asset management options with the base scenario values. Expected annual expenses are the sum of operational, maintenance and quality expenses and their shares are described with dotted lines for option 1 and colored areas for option 2.**



Appendix Figure 5-2 **Expected annual expenses with the different energy price scenarios presented in Chapter 4.2.4 for power transformer unit T37 with alternative asset management options.**

APPENDIX 5



Appendix Figure 5-3 Sensitivity of the overall conclusion between the two asset management options for power transformer T37. The percentage change in the Y-axis is calculated from the difference between the expected net present values for options one and two, with low, base and high economic scenarios.

Appendix Table 5-1 a) Cost factor sensitivity analysis for the expected overall net present valuation of the two options: maintaining or renewing power transformer unit T37. b) The expense difference between the two options and relative change compared to the cost difference in the base evaluation.

a)

	Option 1		Option 2	
	low	*high*	*low*	*high*
Manufacturing prices	623 693 €	757 571 €	579 371 €	732 459 €
Consumption and energy price development	583 753 €	773 095 €	560 951 €	739 955 €
Energy prices	607 260 €	758 007 €	585 095 €	728 415 €
Maintenance expenses	639 423 €	693 952 €	624 226 €	647 061 €
Interest rate	719 506 €	525 463 €	680 354 €	527 029 €
Reliability information	606 343 €	736 736 €	582 634 €	710 752 €

b)

	Difference		Sensitivity	
	low	*high*	*low*	*high*
Manufacturing prices	44 322 €	25 111 €	80 %	2 %
Consumption and energy price development	22 802 €	33 139 €	-7 %	35 %
Energy prices	22 165 €	29 593 €	-10 %	20 %
Maintenance expenses	15 197 €	46 892 €	-38 %	91 %
Interest rate	39 152 €	-1 566 €	59 %	-106 %
Reliability information	23 709 €	25 983 €	-4 %	6 %

APPENDIX 6.1

DSO’s Power Transformer fleet Risk Ranking Scenario

2013		2014		2015		2016		2017		2018		2019		2020	
T18	85 %	**T18**	92 %	**T18**	99 %	**T26**	58 %	**T26**	64 %	**T26**	69 %	**T26**	76 %	**T26**	83 %
T19	80 %	**T19**	87 %	**T19**	93 %	**T25**	45 %	**T25**	49 %	**T25**	53 %	**T25**	57 %	**T25**	63 %
T39	55 %	**T26**	53 %	**T41**	55 %	**T27**	43 %	**T27**	47 %	**T27**	51 %	**T27**	55 %	**T27**	60 %
T40	55 %	**T41**	49 %	**T42**	55 %	**T28**	43 %	**T28**	47 %	**T28**	51 %	**T28**	55 %	**T28**	60 %
T26	49 %	**T42**	49 %	**T26**	53 %	**T24**	39 %	**T14**	43 %	**T48**	47 %	**T48**	53 %	**T14**	57 %
T41	44 %	**T47**	47 %	**T25**	41 %	**T14**	39 %	**T15**	43 %	**T14**	47 %	**T14**	52 %	**T15**	57 %
T42	44 %	**T25**	41 %	**T27**	40 %	**T15**	39 %	**T48**	42 %	**T15**	47 %	**T15**	52 %	**T24**	53 %
T47	42 %	**T11**	38 %	**T28**	40 %	**T48**	38 %	**T24**	42 %	**T24**	45 %	**T24**	49 %	**T23**	50 %
T25	38 %	**T10**	38 %	**T24**	36 %	**T23**	37 %	**T23**	40 %	**T23**	43 %	**T23**	47 %	**T52**	45 %
T11	35 %	**T27**	37 %	**T14**	35 %	**T54**	32 %	**T54**	35 %	**T54**	40 %	**T54**	44 %	**T16**	37 %
T10	35 %	**T28**	37 %	**T15**	35 %	**T52**	30 %	**T52**	33 %	**T52**	37 %	**T52**	41 %	**T11**	33 %
T27	34 %	**T24**	33 %	**T48**	34 %	**T16**	28 %	**T16**	30 %	**T16**	33 %	**T16**	35 %	**T10**	33 %
T28	34 %	**T48**	33 %	**T23**	34 %	**T18**	27 %	**T11**	25 %	**T11**	28 %	**T11**	30 %	**T53**	32 %
T24	31 %	**T14**	32 %	**T54**	29 %	**T19**	27 %	**T10**	25 %	**T10**	28 %	**T10**	30 %	**T45**	29 %
T48	30 %	**T15**	32 %	**T52**	27 %	**T11**	23 %	**T53**	24 %	**T53**	27 %	**T53**	29 %	**T46**	29 %
T23	29 %	**T23**	32 %	**T16**	26 %	**T10**	23 %	**T18**	24 %	**T45**	25 %	**T45**	26 %	**T50**	23 %
T14	29 %	**T45**	31 %	**T53**	20 %	**T53**	22 %	**T19**	24 %	**T46**	25 %	**T46**	26 %	**T51**	23 %
T15	29 %	**T46**	31 %	**T45**	20 %	**T41**	22 %	**T45**	23 %	**T17**	21 %	**T17**	22 %	**T56**	23 %
T45	29 %	**T54**	26 %	**T46**	20 %	**T42**	22 %	**T46**	23 %	**T50**	20 %	**T50**	22 %	**T57**	23 %
T46	29 %	**T16**	25 %	**T17**	18 %	**T45**	21 %	**T17**	20 %	**T51**	20 %	**T51**	22 %	**T17**	23 %
T54	23 %	**T52**	25 %	**T11**	18 %	**T46**	21 %	**T41**	19 %	**T18**	20 %	**T56**	21 %	**T18**	21 %
T16	23 %	**T53**	19 %	**T10**	18 %	**T17**	19 %	**T42**	19 %	**T19**	20 %	**T57**	21 %	**T19**	21 %
T52	23 %	**T39**	19 %	**T47**	18 %	**T50**	18 %	**T50**	19 %	**T56**	19 %	**T18**	20 %	**T48**	21 %
T53	17 %	**T40**	19 %	**T50**	17 %	**T51**	18 %	**T51**	19 %	**T57**	19 %	**T19**	20 %	**T43**	21 %
T17	17 %	**T17**	18 %	**T51**	17 %	**T56**	16 %	**T56**	18 %	**T43**	17 %	**T43**	19 %	**T44**	21 %
T50	16 %	**T50**	17 %	**T39**	16 %	**T57**	16 %	**T57**	18 %	**T44**	17 %	**T44**	19 %	**T54**	18 %
T51	16 %	**T51**	17 %	**T40**	16 %	**T47**	15 %	**T43**	16 %	**T35**	16 %	**T35**	17 %	**T35**	18 %
T56	13 %	**T56**	14 %	**T56**	15 %	**T35**	15 %	**T44**	16 %	**T36**	16 %	**T36**	17 %	**T36**	18 %
T57	13 %	**T57**	14 %	**T57**	15 %	**T36**	15 %	**T35**	16 %	**T39**	15 %	**T39**	16 %	**T39**	17 %
T35	11 %	**T43**	12 %	**T35**	14 %	**T43**	15 %	**T36**	16 %	**T40**	15 %	**T40**	16 %	**T40**	17 %
T36	11 %	**T44**	12 %	**T36**	14 %	**T44**	15 %	**T39**	14 %	**T47**	13 %	**T47**	14 %	**T55**	15 %
T43	11 %	**T35**	12 %	**T43**	13 %	**T39**	14 %	**T40**	14 %	**T55**	13 %	**T55**	14 %	**T47**	14 %
T44	11 %	**T36**	12 %	**T44**	13 %	**T40**	14 %	**T47**	13 %	**T64**	12 %	**T64**	13 %	**T64**	13 %
T20	10 %	**T20**	11 %	**T64**	12 %	**T55**	12 %	**T55**	12 %	**T65**	12 %	**T65**	13 %	**T65**	13 %
T21	10 %	**T21**	11 %	**T65**	12 %	**T64**	11 %	**T64**	12 %	**T12**	12 %	**T12**	12 %	**T37**	13 %
T12	10 %	**T12**	11 %	**T55**	11 %	**T65**	11 %	**T65**	12 %	**T13**	12 %	**T13**	12 %	**T38**	13 %
T13	10 %	**T13**	11 %	**T20**	11 %	**T12**	11 %	**T12**	11 %	**T37**	11 %	**T37**	12 %	**T12**	13 %
T55	10 %	**T55**	10 %	**T21**	11 %	**T13**	11 %	**T13**	11 %	**T38**	11 %	**T38**	12 %	**T13**	13 %
T37	8 %	**T37**	8 %	**T12**	11 %	**T20**	11 %	**T37**	11 %	**T41**	11 %	**T41**	12 %	**T41**	13 %
T38	8 %	**T38**	8 %	**T13**	11 %	**T21**	11 %	**T38**	11 %	**T42**	11 %	**T42**	12 %	**T42**	13 %
T59	6 %	**T59**	6 %	**T37**	9 %	**T37**	10 %	**T20**	11 %	**T20**	10 %	**T29**	10 %	**T29**	11 %
T60	6 %	**T60**	6 %	**T38**	9 %	**T38**	10 %	**T21**	11 %	**T21**	10 %	**T30**	10 %	**T30**	11 %
T61	4 %	**T61**	4 %	**T29**	9 %	**T29**	9 %	**T29**	9 %	**T29**	10 %	**T20**	10 %	**T20**	10 %
T62	4 %	**T62**	4 %	**T30**	9 %	**T30**	9 %	**T30**	9 %	**T30**	10 %	**T21**	10 %	**T21**	10 %
				T59	7 %	**T59**	7 %	**T59**	8 %	**T63**	8 %	**T59**	9 %	**T59**	10 %
				T60	7 %	**T60**	7 %	**T60**	8 %	**T59**	8 %	**T60**	9 %	**T60**	10 %
				T61	5 %	**T61**	5 %	**T61**	5 %	**T60**	8 %	**T63**	9 %	**T63**	9 %
				T62	5 %	**T62**	5 %	**T62**	5 %	**T61**	5 %	**T61**	5 %	**T31**	6 %
				T31	1 %	**T31**	2 %	**T31**	3 %	**T62**	5 %	**T62**	5 %	**T61**	6 %
										T31	4 %	**T31**	5 %	**T62**	6 %

APPENDIX 6.2 MAINTENANCE EXPENSES (1/2)

	BASE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Costs for TBM per unit												
Frequency of TBM in basic maintenance **(in years)**	2											
Cost of transformer unit basic maintanance (€)		967	974	997	1021	1045	1071	1096	1123	1150	1177	1205
Frequency of tap-changer maintenance **(in years)**	6											
Cost of tap-changer unit basic maintanance (€)		1863	1876	1921	1967	2014	2062	2112	2163	2215	2268	2322
25 % share of yearly general substation TBM per unit (€)		1084	1091	1117	1144	1172	1200	1229	1258	1288	1319	1351
Costs for CBM per unit (€)		1252	1260	1291	1322	1353	1386	1419	1453	1488	1524	1560
Costs for on-line diagnostics per unit												
Cost of equipment and installation per unit (€)		16934	16797	16695	16596	16500	16406	16315	16226	16140	16057	15977
Time in operation for on-line diagnostic equipment	10											
OLD yearly mainentance cost, capex 5% (€)		750	748	758	768	779	790	800	812	823	834	846
Costs of support per unit (yearly)												
Support, spare part and warehouse costs (€)		533	537	550	563	577	590	605	619	634	649	665
Costs for corrective maintenance												
Interruption time in forced outage , norm **(Hour)**	0,5											
Cost for serious failure clearing in substation (€)	100000											
Capex increase due the serious failure, 5 years	17 %											
Cost for forced outage failures corrective maint. (€)		68160	68623	70271	71959	73687	75457	77269	79125	81025	82971	84963
Cost for forced outage serious failure corrective maint. (€)		182035	191806	187657	191473	194266	197289	200927	204512	208330	212238	216100
Costs of Preventive maintenance												
Cost of taking unit to Workshop and back (€)	16400											
Cost for Preventive maintenance work, 3 days (€)	7680											
Preventive maintenance in workshop, 3 days (€)	24080											
Costs for repairing parts (€)	10000											
Cost of fault preventive maintenance (€)		17680	17800	18228	18665	19114	19573	20043	20524	21017	21522	22039
Cost of serious fault preventive maintenance (€)		34080	34312	35136	35980	36844	37728	38634	39562	40512	41485	42482

Nominal (€)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Costs for TBM per unit										
Cost of transformer unit basic maintanance **(€)**	1234	1264	1294	1325	1357	1390	1423	1457	1492	1528
Cost of tap-changer unit basic maintanance **(€)**	2378	2435	2494	2554	2615	2678	2742	2808	2875	2944
25 % share of yearly general substation TBM per unit **(€)**	1383	1417	1451	1486	1521	1558	1595	1633	1673	1713
Costs for CBM per unit (€)	1670	1710	1751	1793	1836	1880	1925	1972	2019	2067
Costs for on-line diagnostics per unit										
Cost of equipment and installation per unit **(€)**	15899	15824	15751	15682	15615	15552	15491	15433	15377	15325
OLD yearly mainentance cost, capex 5% **(€)**	857	869	881	893	905	918	930	943	956	969
Costs of support per unit (yearly)										
Support, spare part and warehouse costs **(€)**	681	697	714	731	749	767	785	804	823	843
Costs for corrective maintenance										
Cost for forced outage failures corrective maint. **(€)**	87003	89093	91232	93423	95667	97964	100317	102726	105193	107719
Cost for forced outage serious failure corrective maint. **(€)**	220237	224471	228805	233242	237783	244432	251192	258065	265056	272165
Costs of Preventive maintenance										
Cost for fault preventive maintenance **(€)**	22568	23110	23665	24233	24815	25411	26021	26646	27286	27941
Cost for serious fault preventive maintenance **(€)**	43502	44546	45616	46712	47834	48982	50159	51363	52597	53860

APPENDIX 6.3

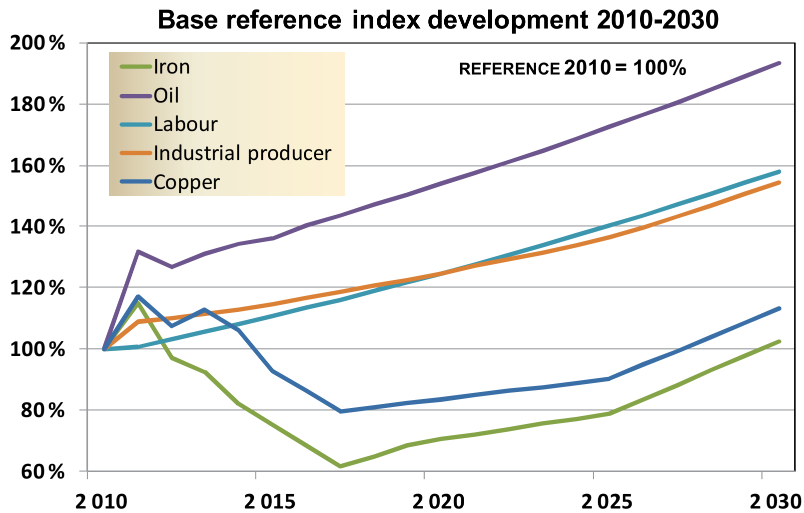
Power transformer fleet's maintenance program

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
T10	T+C	O	T	T	T	O	O	O	O	O	O
T11	T+C	O	T	T	T	O	O	O	O	O	O
T12	lite	lite	lite	lite	lite	lite	lite	lite	lite	T	T
T13	lite	lite	lite	lite	lite	lite	lite	lite	lite	T	T
T14	T+C	T+C	O	O	O	O	T+O	T+O	T+O	T+O	T+O
T15	T+C	T+C	O	O	O	O	T+O	T+O	T+O	T+O	T+O
T16	T+C	O	O	O	O	O	T+O	T+O	T+O	T+O	T+O
T17	T	T+C	T+C	T+C	T+C	O	O	O	O	O	O
T18	T+C+O	T+C+O	O	O	T	T+C	O	O	O	O	O
T19	T+C+O	T+C+O	T+C+O	O	O	T+C	O	O	O	O	O
T20	T	T	T	T	T	T	T	T	T	T	O
T21	T	T	T	T	T	T	T	T	T	T	O
T22	T	T	T	T	T	T	T	T	T	T	T
T23	T+C	T+C	O	O	O	O	O	O	T+O	T+O	T+O
T24	T+C	T+C	O	O	O	O	O	T+O	T+O	T+O	T+O
T25	O	O	O	O	T+O	T+O	T+O	T+O	T+O	T+O	T+C+O
T26	T+O	T+O	T+O	T+O	T+O	T+O	T+C+O	T+C+O	T+C+O	T+C+O	O
T27	T+C	O	O	O	O	T+O	T+O	T+O	T+O	T+O	T+C+O
T28	T+C	O	O	O	O	T+O	T+O	T+O	T+O	T+O	T+C+O
T29			lite	lite	lite	lite	lite	lite	lite	lite	lite
T30			lite	lite	lite	lite	lite	lite	lite	lite	lite
T31			lite	lite	lite	lite	lite	lite	lite	lite	lite
T32			lite	lite	lite	lite	lite	lite	lite	lite	lite
T33											
T34											
T35	lite	T	T	T	T	T	T	T	T	O	O
T36	lite	T	T	T	T	T	T	T	T	O	O
T37	lite	lite	T	T	T	T	T	O	O	O	O
T38	lite	lite	T	T	T	T	T	O	O	O	O
T39	T+O	T+O	T+C+O	T+C+O	O	T	T	T	T	T	O
T40	T+O	T+O	T+C+O	T+C+O	O	T	T	T	T	T	O
T41	T+C+O	T+C	T+C	T	T	lite	lite	lite	lite	T	T
T42	T+C+O	T+C	T+C	T	T	lite	lite	lite	lite	T	T
T43	T	T	T	T	T	T	O	O	O	O	O
T44	T	T	T	T	T	T	O	O	O	O	O
T45	O	T+O	T+C	O	O	O	O	O	O	O	O
T46	O	T+O	T+C	O	O	O	O	O	O	O	O
T47	T+O	O	T+C	T+C	T+C	O	O	O	O	O	O
T48	O	T+O	T+O	T+O	T+O	O	O	O	O	O	O
T49	T	T	T	T	T	T	T	T	T	T	T
T50	T	T	T	T+C	T+C	O	O	O	O	O	O
T51	T	T	T	T+C	T+C	O	O	O	O	O	O
T52	T	T	T+C	T+C	O	O	O	O	O	T+O	T+O
T53	T	T	T	T	T	T	O	O	O	O	O
T54	T	T+C	T+C	O	O	O	O	O	T+O	T+O	O
T55	lite	lite	lite	lite	T	T	T	T	T	T	O
T56	T	T	T	T+C	T+C	O	O	O	O	O	O
T57	T	T	T	T+C	T+C	O	O	O	O	O	O
T58	T	T	T	T	T	T	T	T	T	T	T
T59	lite	lite	lite	lite	lite	lite	lite	lite	lite	lite	lite
T60	lite	lite	lite	lite	lite	lite	lite	lite	lite	lite	lite
T61	lite	lite	lite	lite	lite	lite	lite	lite	lite	lite	lite
T62	lite	lite	lite	lite	lite	lite	lite	lite	lite	lite	lite
T63						lite	lite	lite	lite	lite	lite
T64			T	lite	lite	lite	lite	T	T	T	T
T65			T	lite	lite	lite	lite	T	T	T	T

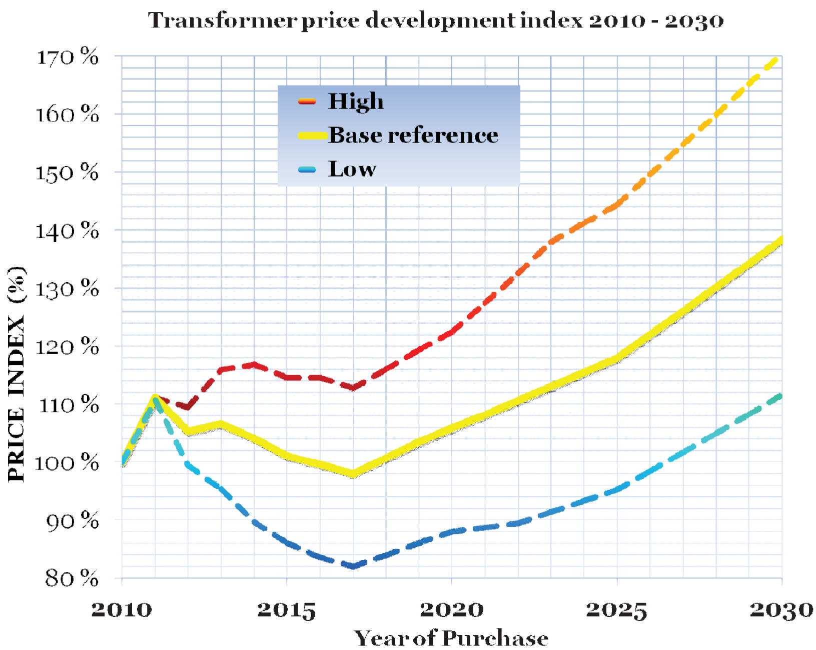
T = Time-based Maintenance, C = Condition-based Maintenance, O = Online diagnostics
Tlite = Light Time-based Maintenance

APPENDIX 7

Power transformer price development projection view 2012



Appendix Figure 7-1 **Expected base price index development, forecast in June 2012.**

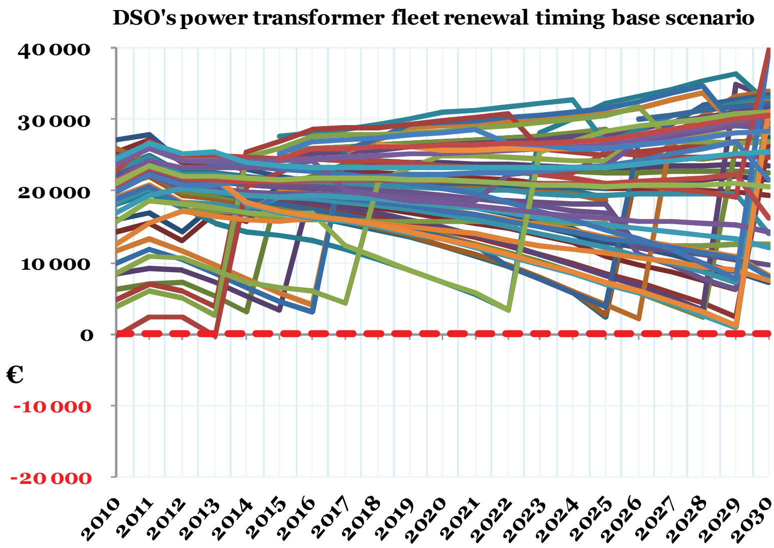


Appendix Figure 7-2 **Expected power transformer price index development projection made in June 2012, applying Word Bank June 2012 estimations and average developments for labour and industrial producer indices.**

APPENDIX 8

Power transformer renewal point assessment

UNIT INFORMATION			RENEVAL TIME			
	Manufacturing (year)	Rated Power (MVA)	**Renewal point with TBM**	**Renewal age with TBM**	*Final renewal point with intensive maint.*	*Final renewal age with intensive maint.*
T14	1986	40	**2026**	**40**	*2031*	*45*
T15	1986	40	**2026**	**40**	*2031*	*45*
T18	1976	31,5	**2015**	**39**	*2022*	*46*
T19	1977	31,5	**2016**	**39**	*2023*	*46*
T23	1989	31,5	**2030**	**41**	*2031*	*42*
T24	1988	31,5	**2029**	**41**	*2031*	*43*
T25	1986	31,5	**2029**	**43**	*2031*	*45*
T26	1981	31,5	**2023**	**42**	*2031*	*50*
T27	1985	31,5	**2027**	**42**	*2031*	*46*
T28	1985	31,5	**2026**	**41**	*2031*	*46*
T39	1972	40	**2017**	**45**	*2024*	*52*
T40	1972	40	**2017**	**45**	*2023*	*51*
T41	1976	40	**2014**	**38**	*2026*	*50*
T42	1976	40	**2014**	**38**	*2024*	*48*
T47	1975	40	**2014**	**39**	*2018*	*43*
T48	1980	40	**2018**	**38**	*2023*	*43*
T54	1980	40	**2023**	**43**	*2030*	*50*



Appendix Figure 8-1 Renewal timing assessment for the entire power transformer fleet with TBM maintenance intensity and renewal times applied from the upper table renewal timing, before the unit's curves gain negative values.

Aalto-DD 9/2014

Power systems are deeply interconnected to global economics in a multidimensional manner. Indeed, asset management in electricity distribution is simultaneously affected by a multitude of economic factors, including: electricity demand, network expansion requirements, the time value of money, and component, construction and operational expenditures. This thesis is a research journey from electrical distribution systems to global economics, and finally to power transformer unit asset management.

This thesis offers an approach to assess techno-economic dependencies in electricity distribution asset management within a changing economic environment. Understanding the dynamic balance between asset management and overall expenses is increasingly important while seeking economic efficiency and return on investments.

ISBN 978-952-60-5538-1
ISBN 978-952-60-5539-8 (pdf)
ISSN-L 1799-4934
ISSN 1799-4934
ISSN 1799-4942 (pdf)

Aalto University
School of Electrical Engineering
Department of Electrical Engineering
www.aalto.fi

BUSINESS +
ECONOMY

ART +
DESIGN +
ARCHITECTURE

SCIENCE +
TECHNOLOGY

CROSSOVER

DOCTORAL
DISSERTATIONS