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Erling Tønne

Doctoral thesis

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Thesis for the Degree of
Philosophiae Doctor
Faculty of Information Technology, Mathematics
and Electrical Engineering
Department of Electric Power Engineering

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With emphasis on probabilistic load and generation modelling based on data from smart meters

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PREFACE

This thesis is submitted as a part of the fulfilment of the requirements of the degree Philosophiae Doctor, PhD, at the Department of Electric Power Engineering at the Norwegian University of Science and Technology (NTNU) in Trondheim.

The work leading to this thesis was performed during the periods January 2011 – December 2014 and November 2015 – December 2016. Kjell Sand, Adjunct Professor at NTNU and senior researcher at SINTEF Energy Research, has been the main supervisor. Jan A. Foosnæs, Adjunct Associate Professor at NTNU and special advisor at NTE Nett, has been the co-supervisor.

The work has been carried out at NTNU, Department of Electric Power Engineering in Trondheim and NTE Nett, Department of Strategy and Analysis in Steinkjer, my hometown.

NTE Nett and the Research Council of Norway has funded the work as a part of the Industrial PhD scheme.

Steinkjer, December 2016

Erling Tønne

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First, I would like to thank my supervisors Adjunct Professor NTNU Kjell Sand and Adjunct Associate Professor NTNU/special advisor NTE Nett Jan A. Foosnæs for their good help and support. Their optimistic attitude and guidance have helped me a lot through the work.

I would also like to thank my funders NTE Nett and The Norwegian Research Council for believing in me and giving me the opportunity to do this work. Without the Industrial PhD scheme, I would never have been able to do this PhD-work.

My thanks also go to my colleagues in NTE Nett for good support and helpful discussions during this work. Thank you Rune Paulsen, Hans Finstad, Frode Johannessen, Bernhard Bolsøy, Eirik Thorshaug and Petter Efskin!

At last but not least, I will give my wife and four children a warm and grateful big hug and lots of kisses for their love, understanding and support during these years. Thanks for having been faithful and persevered with me.

SUMMARY

The energy sector is the largest source of greenhouse-gas emissions, and has therefore a crucial role to play in tackling the climate change. Every facets of the energy sector, and especially the power generation, needs to transform their carbon performance. Renewable energy sources (RES) are reducing the use of fossil fuels and energy efficiency is reducing the need for energy.

The amount of RES connected to the distribution grid is increasing. Generation from RES is unregulated and will vary in time according to e.g. solar radiation, wind speed or available water flow in the river.

The desire to be energy efficient encourage electricity consumers to buy and install high powered appliances that are being switched on and off frequently. The load is about to become more fluctuating with a certain stochastic character.

Extended use of control equipment, sensors and ICT in the distribution system will make it possible to connect more RES to the distribution grid, controlling the load flow in the grid and make the grid more robust regarding operational disturbances.

The DSO will get a lot more data from meters, sensors, control systems etc. that can be used to make better long term plans for grid development.

In this PhD work a new probabilistic method for load and generation modelling is proposed and compared with today's deterministic method. Probabilistic network calculations (load flow) are performed with Monte Carlo simulations. The methods are tested against each other in a demo case consisting of a LV grid with seven different loads and a generator. The results from the test show that:

- Probabilistic calculations give better results than today's deterministic calculations since probabilistic calculations give results presented as probability distribution functions instead of the deterministic (one single value) result.

- Power system planning based on probabilistic simulations will give better results – both technically and economically. The overinvestment in grid capacity will be reduced and the exploitation of the grid capacity will be higher.

Power system planning in the future should be performed with individual probabilistic loads and generation models and Monte Carlo simulations for load flow calculations. The new model described in this thesis should be adapted to existing software planning systems.

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NOMENCLATURE AND ABBREVIATIONS

ABBREVIATIONS

ADS	Active distribution systems
AMI	advanced metering infrastructure
AMR	automatic meter reading
AMS	Advanced metering and control systems (Norwegian). 3 main functions: Metering, communication and control. (Ref.: NVE Dok 1/2011)
CAPEX	Capital expenditures are the funds that a business uses to purchase major physical goods or services to expand the company's abilities to generate profits (www.investopedia.com)
CCS	carbon capture and storage
CEN	European Committee for Standardization
CENELEC	European Committee for Electro technical Standardization
CENS	Cost of energy not supplied
CHP	combined heat and power
CSP	Concentrated Solar Power
DER	distributed energy resources
DG	distributed generation
DMS	distribution management system
DNO	distribution network operator
DR	demand response
DSO	distribution system operator
EHV	Extra High Voltage, Above 230 kV, Transmission grid (Ref.: IEC 60038:2009)
EMC	electromagnetic compatibility
EMS	energy management system
ENS	Energy not supplied
ESCO	Energy Service Company
ESO	European Standardization Organization (CEN, CENELEC and ETSI)
ETP	European Technology Platform
ETSI	European Telecommunications Standards Institute
EU	European Union
Eurelectric	Union of the Electricity Industry
EV	electric vehicle
FACTS	flexible alternating current transmission system
GHG	greenhouse gases
HDD	Heating Degree Days. A measure of the heating demand
HV	High Voltage, 35 – 230 kV, Distribution grid (Ref.: IEC 60038:2009)
ICT	information and communication technologies
IEC	International Electro technical Commission
IED	intelligent electronic device
IEEE	Institute of Electrical and Electronics Engineers
IOP	Interoperability, the ability of two or more networks, systems, devices to interwork, to exchange information in order to perform required functions.

KPI	Key Performance Indicator
LV	Low voltage, Up to 1 kV, Distribution grid (Ref.: IEC 60038:2009)
MCDA	Multiple Criteria Decision Analysis is a sub-discipline of operations research that explicitly evaluates multiple conflicting criteria in decision-making.
MCDM	Multiple-criteria Decision-making (see MCDA)
MV	Medium Voltage, 1-35 kV, Distribution grid (Ref.: IEC 60038:2009)
OPEX	Operating expense - results from the ongoing costs a company pays to run its basic business (www.investopedia.com)
PLC	Power Line Communications
PMU	Phasor Measurement Unit
PV	Photovoltaic
R&D	Research & Development
RES	Renewable Energy Sources
RTTR	Real Time Thermal Rating
SCADA	Supervisory Control And Data Acquisition
SGAM	Smart Grid Architecture Model
TSO	Transmission System Operator, also system administrator
UNFCCC	United Nations Framework Convention on Climate Change
V2G	Vehicle to Grid
V2H	Vehicle to Home
VPP	Virtual Power Plant

NOMENCLATURE:

Active distribution grid	A network including voltage sources and/or current sources (Ref.: IEC, Electropedia). A network containing active elements like voltage and reactive power management, distribution network capacity management, congestion management and information exchange between TSOs, DSOs and distributed energy resources (DER) for coordinated control.
Bottleneck	Situation that occurs when the need for grid capacity is larger than the transmission limit. (ref.: http://www.lovdata.no/for/sf/oe/xe-20020507-0448.html)
Bottleneck costs **Congestion costs**	Also referred to as capacity price. It occurs when there is a shortage of transmission capacity in the network (not enough access to electricity). Such bottleneck costs typically increases with increasing scarcity of transmission capacity.
Consumer / End-user	Buyer of electric energy that does not resell. Often divided into groups (i.e. household, farming, industry, trade and services, public entities and holiday homes) (Ref.: http://www.lovdata.no/for/sf/oe/xe-19990311-0301.html)
Deterministic load/generation model	Deterministic technique, which assumes no uncertainty in model parameters. Typical models are maximum and minimum load during the last 5-10 years. Generation is usually modelled as maximum (rated generation) and zero generation.
Household	Consumer of electric energy in a house or apartment. Holiday homes and cottages are not included in this category. (Ref.: http://www.lovdata.no/for/sf/oe/xe-19990311-0301.html)
Instantaneous balance	Equilibrium between total consumption and total power generation, taken into account the exchange of power with other connected power systems. (ref.: http://www.lovdata.no/for/sf/oe/xe-20020507-0448.html)
Interchangeability	The ability of two or more devices or components to be interchanged without making changes to other devices or components in the same system and without degradation in system performance. The two devices do not communicate with each other, but one can simply be replaced by another.
Interoperability	The ability of two or more networks, systems, devices, applications or components to interwork, to exchange and use information in order to perform required functions.
Interruptible load	The load of particular consumers, which, according to contract, can be disconnected by the supply undertaking for a limited period of time. (Ref.: http://www.lovdata.no/for/sf/oe/oe-19990311-0302.html)
Interruption	Situation characterized by the loss of supply to one or several consumers where the supply voltage is below 1 % of the agreed voltage level. The interruptions are in Norway classified into long interruptions (> 3 min) and short interruptions (≤ 3 min). (Ref.: http://www.lovdata.no/for/sf/oe/xe-20041130-1557.html)
Low prioritized load	Load/consumption that can be disconnected for a limited period of time. The consumer does not have a fuel-fired reserve. (Ref.: SINTEF TR A6425, 2007)

Not prioritized load	Load/consumption that can be disconnected for an unlimited period. The consumer does have a fuel-fired reserve.
Operational interference	Protection tripping, enforced or unintentional disconnection or unsuccessful connection as a result from faults in the power system. (Ref.: http://www.lovdata.no/for/sf/oe/xe-20020507-0448.html)
Passive distribution grid	A network including neither voltage sources nor current sources (Ref.: IEC, Electropedia). A network with no active elements for coordinated control of voltage or power flow. Real time control problem are resolved at the planning stage ("Fit and forget").
Power factor	Also referred to as cos(φ) and describes the relationship between active power (kW) and reactive power (kVAr). φ (greek letter Phi)
Prioritized load	Load/consumption that can not be disconnected.
Probabilistic load/generation model	Statistical model based on historical data describing the probability of an event to occur. The event in this case is the size of one load or generation.
Prosumer	A prosumer produces and consumes electricity, often through rooftop solar panels, and sells it back to the grid.
Quality of supply	Quality of the delivery of electricity according to specific criteria. Quality of supply is often divided into: • Reliability (interruption conditions) • Voltage quality • Customer service / information to customers (ref.: http://www.lovdata.no/for/sf/oe/xe-20041130-1557.html)
Reliability of delivery	The ability of the power system to deliver electric energy to the end-user. Reliability is associated with interruption frequency, and -duration in supply voltage. (ref.: http://www.lovdata.no/for/sf/oe/xe-20041130-1557.html
Renewable energy	Energy from renewable energy resources (RES) including i.a. wind, solar, geothermal, ocean, hydro, gas from landfills, gas from sewage plants and biomass. (Ref.: http://www.lovdata.no/for/sf/oe/xe-20071214-1652.html)
Risk	The possibility that the actual results differ from the expected results. *Risk = Probability x Consequence*
Risk analysis	Systematic use of available information to identify hazards and to estimate the risk. Can be done qualitative (e.g. risk matrices) or quantitative (e.g. Monte Carlo simulations).
Sensitivity analysis	Analysis performed to see the effect of changes in the underlying data. Testing the robustness of the results of a model in the presence of uncertainty in its inputs. Gives increased understanding of the relationships between input and output variables in a system or model. (Ref.: Wikipedia)
System responsibility	The system responsibility shall be carried out in a socially efficient manner. The system administrator (TSO) should ensure that there always is a balance between the total generation and the total consumption in the system, taken into account the power exchange with affiliated foreign power system. It shall be made for an adequate power quality in all parts of the country. (Ref.: http://www.lovdata.no/for/sf/oe/xe-19901207-0959.html)

The Velander formula	A method that estimates the annual peak load for an electricity consumer, based on the consumer's annual energy consumption.
Time of use (TOU) pricing	A variable rate structure that charges for energy depending on the time of day and the season the energy is used. With TOU rates, the energy bill will be determined by both when and how much electricity is used.
Transmission limit / Thermal limit	Maximum allowed transferred active power in the distribution/transmission grid or on a single distribution/ transmission line/cable. (ref.: http://www.lovdata.no/for/sf/oe/xe-20020507-0448.html)
Use case	A methodology used in system analysis to identify, clarify and organize system requirements. The use case is made up of a set of possible sequences of interactions between systems and users in a particular environment and related to a particular goal.
Utilization time	The quotient, expressed in hours, of the consumption within a specified period (e.g., year, month, day, etc.), and the maximum or other specified demand occurring within the same period. Note – This term should not be used without specifying the demand and the period to which it relates. (www.electropedia.org) Utilization time (h) = annual energy consumption (kWh) / Peak load (kW). Annual peak load for an electricity consumer can be estimated by the consumer's annual energy consumption and an estimated (standard) utilization time for that type of consumer.
Voltage quality	Voltage quality according to given criteria. Voltage quality includes the following characteristics: • Frequency • Slow rms-variations • Fast rms-variations - flicker • Voltage dips • Temporary over voltages phase to ground • Transient over voltages • Voltage unbalance • Harmonics • Inter harmonics • Signal transmission on the power grid (Ref.: http://www.lovdata.no/for/sf/oe/xe-20041130-1557.html)

PART I – Introduction and State of the art

1. Introduction

1.1 Background and motivation

The electric distribution system is undergoing a profound change driven by:

- Integration of distributed generation from renewable energy sources (RES)
- Changes in load pattern induced by electric vehicles (EVs), heat pumps, more power intensive devices, demand response schemes, etc.
- Increased reliability requirements and voltage quality challenges
- The needs for renewal of ageing assets
- New opportunities for more cost efficient operation facilitated by new technologies and new data (e.g. smart meters, distribution management systems, digital substations, new sensors, batteries, etc.)

Grid reliability, operational efficiencies and customer services should be maintained and improved solving the new challenges and utilizing the new options. The changes that are happening are particularly significant for the electricity distribution grid, where “blind” and manual operations, along with the electromechanical components, will need to be transformed into a “smart grid.” This transformation will be necessary to meet environmental targets, to accommodate a greater emphasis on demand response, and to support distributed generation, electric vehicles and storage capabilities.

These needs and changes present the power industry with the biggest challenge it has ever faced. On one hand, the transition to a smart grid has to be evolutionary to keep the lights on; on the other hand, the issues surrounding the smart grid are significant enough to demand major changes in power systems operating philosophy.

The Norwegian distribution networks have been developed over many years and have a relatively small amount of active elements, such as generators and demand side management. They are instead dominated by passive elements, principally uncontrolled loads. In the future the loads will become more dynamic and controllable due to more active response from customers and the expected large introduction of electronic control and regulation systems. At the same time the introduction of advanced metering systems (AMS, smart meters) and new sensors will provide the network owner with a lot more data [1].

The introduction of more active elements will require new and improved methods for distribution system planning especially for the estimation of loads and generation in the future distribution networks. The optimal investments or reinvestments in the distribution system is a consequence of the capacity needed to host the expected loads and generation. Thus, good estimates of load and generation are imperative to optimize the distribution grid.

The basis for the PhD-work can be found in different articles and reports (for example [2], [3], [4], [5], [6]).

1.2 Objectives

The overall objective of the PhD-work is to contribute to improve distribution system planning to support the transformation of today’s passive distribution networks into the expected future active distribution networks. Methods for planning and estimation of loads and generation are especially addressed in order to find out if this can be done in a better way than with today’s methods – taken in consideration the large amount of new data available for planners from the new smart meters.

The main research questions addressed are:

(1) What changes can be expected in the distribution system during the next decades, and what will be the consequences regarding distribution systems planning and operation?
(2) Is the methodology used by DSOs in Norway today for distributions system planning good enough or can it be improved?
(3) As load and generation modelling is essential in distribution system planning and huge amount of new data becomes available by the introduction of smart meters, how can data from the new smart meters be used to make better load- and generation models for distribution system planning purposes? Should the load and generation models be probabilistic rather than deterministic as today?
(4) How can probabilistic load-flow calculations be done with the availability of more stochastic load and generation models?
(5) Will probabilistic models and calculations give better results than today's methods?

1.3 Scope

The scope of this thesis is to develop, test and evaluate new methods for power system planning in distribution systems with increased penetration of demand response (DR) and renewable energy sources (RES).

The area of special focus for the PhD-work are methods for modelling of load and generation and load flow calculations in the future active electricity distribution networks. The work is focused on Norwegian conditions and using a local DSO (NTE Nett) as a case.

1.4 State of the art

Power system planning have traditionally been performed according to a deterministic approach. Load models have been based on:

- Peak load calculated from annual energy consumption and standard utilization times for different load categories
- Standard load variation curves for different load categories (yearly variation and daily variation).

Generation have been modelled as either full or no generation (installed capacity or zero).

The electric distribution grids have been dimensioned according to a "fit-and-forget" approach, meaning that the grid will manage every possible load situation that can occur during its operating life.

As the loads and generation from RES become more variable and stochastic in character, this fit-and-forget approach will be expensive and challenging to meet.

Smart meter deployment is spurring renewed interest in analyzing techniques for electrical usage data. Smart meters and new sensors in the smart grids provide the DSOs with a lot of new information and possibilities to handle the increased uncertainty in load and generation.

A search for published articles within the same area as the present thesis resulted in several hits in the Scopus database and Google Scholar. Most of the reports found were dealing with the following topics:

- Load disaggregation based on data from smart meters
- Home appliance load modelling
- Bottom-up methods for residential load modelling
- Load modelling and state estimation for operational issues like e.g. real time and day ahead load forecast, voltage control, self-healing, etc.

Only a few of the reports that were found, are dealing with topics closely related to subjects in the present thesis:

- J. F. Toubeau*,* et al*.* [7] describe a method for statistical load and generation modelling for long term studies of low voltage networks in presence of sparse smart metering data. The objective is to establish reliable individual stochastic models for every LV consumers (e.g. residential, commercial, etc.) and distributed generators, even those without metering devices. The method is based on:
    - Segmentation of end-users into representative clusters
    - Within each cluster, all available SM information is used to extrapolate statistical load profiles of all components.
    - Standardized cumulative distribution function is used to describe the variation between the end-users in the same cluster.
    - Monte Carlo simulations are used for Network calculations.

- F. Provoost*, et al* [8] describe the use of data from smart meters at LV customers to obtain knowledge of load behavior, load profiles and coincidence factors. Data from 200 smart meters obtained during the winter of 2010, was analyzed. Statistical and mathematical load models are not developed. The conclusions are based on real data from smart meters.

- M. Nijhuis*,* et al. [9] describe a stochastic household load modelling from a smart grid planning perspective. The required level of detail in modelling the household load is assessed in order to limit the increased computational burden associated with the increased complexity in network load. The effect of different aggregation levels of household load curves on the error in estimated voltage deviations is demonstrated, as well as the impact of varying degrees of availability for data regarding demand-side management (DSM) on the expected peak load reduction. The required level of load curve aggregation is determined depending on the feeder characteristics and the grid operators risk-taking. They show that incorporating DSM in network planning requires a high level of data availability, as the amount of expected DSM drops significantly when less measurement data is available.

- V. Klonari*, et al.* [10] presents a Monte-Carlo (MC) framework that simulates the steady operation of the LV network by elaborating user-specific smart metering (SM) measurements. The presented framework integrates a complete three-phase power flow algorithm that can analyze most possible LV network configurations, balanced and unbalanced, considering nodal power injections and consumptions as random variables of each network state.

In addition, the report from CIGRÉ Work group C 6.19 [11] represents an important contribution to this topic. It is referred to this CIGRÉ-report several times in this thesis.

1.5 Contributions

Six conference papers and two other publications have been written and published during this work.

Table 1-1 Published conference papers

Date	Conference	Theme	Paper	Poster	Oral presentation	Co-Authors
June 2012	Cired Workshop 2012	Integration of DG. The Namsskogan Case	X 0146	X		Kjell Sand Jan Foosnæs Rune Paulsen
Sept. 2012	Nordac 2012	Composite Poles	X		X	Vidar Dale Jan A Foosnæs
June 2013	Cired 2013	Composite Poles	X 1393		X	Vidar Dale Jan A Foosnæs
June 2013	Cired 2013	Network Planning in NTE Nett today and in the Future	X 1426			Jan A Foosnæs Terje Pynten
June 2013	Cired 2013	Demand Side Management (DSM)	X 0377		X	Jan A Foosnæs Jan O Gjerde Virginia Hyde
June 2015	Cired 2015	New Planning Method for Smart and Active Distribution Grids	X 1149	X		Jan A. Foosnæs Kjell Sand

Table 1-2 Published journal and magazine articles

Date	Journal /Magazine	Theme	Paper	Co-Authors
April 2013	Journal of Energy and Power Engineering (JEPE) (http://www.davidpublisher.org/Home/Journal/JEPE)	Finding Maintenance Project to Priority	Paper	Terje Pynten Jan A Foosnæs Johan G Hernes
Dec. 2013	The Norwegian magazine "Energiteknikk" (http://energiteknikk.net/)	Smart plans for smart distribution grids – What methods and knowledge is required?	Article	

1.6 Thesis outline

The thesis is organized as follows:

PART I – Introduction and State of the art
PART II – Changing conditions for operating and planning of distribution grids
PART III – Planning methodology for the future smart and active distribution grids
PART IV – Testing and verification
PART V – Discussion and conclusion

APPENDIX A – Demo case – calculation results
APPENDIX B – Renewable energy sources (RES)
APPENDIX C – Smart grid architecture

2 Distribution system planning in general

Distribution system planning covers in principle everything from connecting a new house to low voltage distribution network and up to making long-term plans for development of the medium and high voltage distribution networks. The network planning methodology may also advantageously be used to plan renewal and reinvestments in the network.

When connecting a new house the administrative and engineering-related processes will dominate the practical work, while technical and economic aspects have a minor role. When making plans for the long-term development of HV distribution system investments, then technical and economic assessments will play a dominant role. Regardless of the voltage level, power system planning and decision making will strongly affect the network company's finances and efficiency, both in the short and long term.

The introduction of new technologies and new types of components into the distribution network will make the distribution systems more complex. Today's passive distribution networks which make use of the so-called "fit-and-forget" approach, will gradually be transformed with the use of an active management approach to Smart Grids i.e. a complex system of systems. The use case concept is helpful to structure the transition to the new smarter system. One way to describe the transition is to state that it will be realized by implementing new use cases with their associated technologies.

Complex systems such as Smart Grids call for cooperation between experts from several different domains (e.g. power engineering, telematics, ICT, etc.) and the use case methodology is regarded as the state-of-art platform for such interdisciplinary cooperation and communication. The use case methodology has its origin in software engineering and has alter been adapted to the Smart Grid domain. The IEC PAS 62559 *IntelliGrid methodology for developing requirements for energy systems* published in 2008 was an important milestone in this development and the use case methodology has been increasingly used within the Smart Grids.

Wikipedia describe the term ***use case*** like this[1]:
In software and system engineering, a use case is a list of actions or event steps, typically defining the interactions between a role (known in the Unified Modelling Language as an actor) and a system, to achieve a goal. The actor can be a human, an external system, or time. In systems engineering, use cases are used at a higher level than within software engineering, often representing missions or stakeholder goals. The detailed requirements may then be captured in the Systems Modelling Language (SysML) or as contractual statements.

Use case analysis is an important and valuable requirement analysis technique that has been widely used in modern software engineering since its formal introduction by Ivar Jacobsen in 1992. Use case driven development is a key characteristic of many process models and frameworks such as ICONIX, the Unified Process (UP), the IBM Rational Unified Process (RUP), and the Oracle Unified Method (OUM). With its inherent iterative, incremental and evolutionary nature, use case also fits well for agile development.

2.1 Overall objective

The overall objective as stated in the Norwegian Energy Act (§ 1.2) is to ensure that generation, conversion, transmission, trading and distribution of energy are rationally carried out for the benefit of society, having regard to the public and private interests affected. This means that the development towards a Smart Grid should be done using a holistic approach considering all costs and impacts for all stakeholders. This is of particular importance for Smart Grid decisions as some functionality might give increased costs for some stakeholders while others get benefits from the same functions (use cases). As an example, increased energy efficiency might reduce the electricity bill for network customers, while energy sales companies and generators get reduced income [12].

[1] https://en.wikipedia.org/wiki/Use_case

The overall objective for the Energy Act can be met by applying socio-economic planning principles and analysis. The main objective of socio-economic analyses is to *explain and make visible the consequences of alternative measures before the decisions are made.* Such consequences include among other things costs to be charged public budgets, income changes in households, income changes in business/industries and impacts on health, environment and safety. A socio-economic analysis is a way to systemize and analyze available information concerning costs, benefits and risks to balance stakeholder objectives and to evaluate if possible measures are socio-economic profitable [12].

It is important that the investigation of competing alternatives (use cases) are structured and handled equally. Vital premises for ranking of different alternatives should especially be made visible. The following main principles are important to meet in a socio-economic analysis:

1. All relevant alternatives should be evaluated
2. All relevant impacts of the different alternatives for all stakeholders affected should be included
3. The different alternatives should be compared with the reference alternative, which might be the existing system solution (the "do nothing" solution).
4. It is recommended to seek flexible and robust solutions with respect to the uncertainties involved.

This means that the network companies shall act to benefit society. This is not necessarily the same as maximizing the company's financial results. There are costs associated with the grid operations that are not stated in the companies' accounts, but is charged customers, industry and environment. These costs shall, according to the Energy Act, affect the companies' behaviors, and NVE (The Norwegian Water Resources and Energy Directorate) is set to ensure that Norwegian network companies are driven according socio-economic principles.

As a result of the liberalization in the industry and society in general, the trend has been that the network companies are acting increasingly commercially. As an answer to this, the authorities are adapting the regulatory framework by introducing new regulations and licensing procedures in order to motivate the network operators to act according to socio-economic principles.

2.2 Socio-economic analyses – the foundation for evaluation

2.2.1 General principles

Cost benefit analysis and *cost-effectiveness analysis* are the two most common methodologies used in socio-economic analysis.

In a complete *cost-benefit analysis,* all effects are evaluated in monetary terms. The values are used to quantify the different costs and benefits. Alternatives are socio-economic profitable when the sum of all benefits over the evaluation horizon is larger than the sum of all costs.

The main principle for the valuation in socio-economic cost-benefit analyses is that the value of a benefit is set equal to the population's willingness to pay for it. Socio-economic profitability hence means that the population has an aggregated willingness to pay at least equal to the actual cost of the alternative. Even if the total willingness to pay is larger than the costs, it does not necessarily mean that the alternative is wanted by the society. One of the reasons is that not all consequences can be measured in monetary terms. Another reason is that people also are interested in how the benefits and costs are distributed within the population – which in turn might influence decisions. (If e.g. an alternative is socio-economic profitable, but mainly benefits only the rich, it might be politically complicated to implement the alternative.)

In a *cost-effectiveness* analysis the alternatives are measured **only in terms of costs** – the benefits are not estimated. This kind of analysis is used in cases where it is not straight forward to evaluate the benefits in monetary terms (as e.g. deciding on building a new opera house). *Cost-effectiveness* analyses assume that there exists a given objective for the project, and that all qualified alternatives will fulfil this objective with no extra benefits. The purpose of cost-effectiveness analyses is to find the alternative that minimizes the total costs to fulfil the objective.

Other impacts than costs should be described and included in the decision making process and this can be done either by introducing constraints in the decision criteria, or to allocate cost attributes to also more intangible aspects like environmental impacts.

The main steps of a socio-economic analysis are given in Figure 2-1.

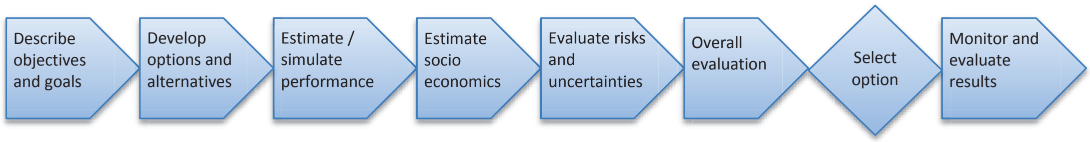


Figure 2-1 Steps in a socio-economic analysis [12]

The steps are briefly commented below:

Describe objectives and goals
In any decision making process, objectives and goals need to be formulated as a reference for evaluation. An objective function is a formal way of expressing planning objectives or goals. The objectives in a socio-economic planning process should be consistent with regulatory requirements (external) and company objectives (internal). If internal and external objectives are conflicting, it is in principle the role of the regulators to provide a planning framework that gives incentives for socio-economic decision making. As an example, in Norway the overall planning objectives for the DSOs and the TSO (Statnett) are specified by the regulator (NVE).

Develop options and alternatives
The problem in a planning process might be defined as the gap between the "present situation" and the "desired situation" with respect to the planning objectives. Hence, to develop alternatives means here to identify use cases that are expected to improve the planning objective i.e. closing the gap. Use case repositories (databases) provide a good starting point for the development and selection of use cases to be analyzed further, and such repositories are available on the internet e.g. http://smartgridstandardsmap.com.

Estimate / simulate performance
To assess the performance of use cases over the planning horizon, some kind of simulation methodology or tools are needed. As use case investments might have long technical life times, the period of analysis should be equally long to assess the future effect of present decisions over the life cycle of the use case investments. As an example, smart meters typically have a technical life time of 15 years.

For grid oriented use cases, simulation of technical performance over the planning horizon are normally carried out by using different standard simulation tools such as:
- Load flow analyses
- Short circuit analyses
- Reliability analyses
- Voltage quality analyses

Such simulations provide parameters that are needed in the subsequent phases of the planning process, and the simulations are also helpful to filter out the use cases that do not satisfy the planning restrictions – e.g. use cases that give a voltage quality outside the planning limits.

For generation and market oriented use cases, often future expectations on market prices for electricity play a significant role to estimate use case performance under different scenarios. Many tools and models are available for long term electricity price forecasting. In the Nordic countries the EMPS program ("EFI's Multi-area Power-market Simulator") is used for optimization and simulation of hydro-thermal power systems with a considerable share of hydropower. The tool can be used to provide long term forecast for electricity prices in deregulated markets. See [13] for more information.

Estimate socio economics
This step includes estimating the socio-economic costs and benefits for all alternatives (use cases) that have not been eliminated from the study during the performance simulation phase. As stated earlier, **all** costs, benefits and other impacts for **all** stakeholders should in principle be considered. As this might be rather challenging, some simplifications are normally needed.

For decisions in transmission or distribution grids the following socio-economic cost elements are required by the regulator to form the decision base:

- Investment costs
- Operation and maintenance costs
- Cost of electrical losses
- Cost of interruptions for the TSOs/DSOs and their customers
- Bottleneck costs

As only costs are included, the objective is to minimize overall network costs while satisfying relevant restrictions. (Benefits are represented as saved costs so the approach has the character of being a cost benefit analysis rather than a cost-effectiveness analysis.)

For decisions in generation, market or electricity use oriented use cases, both socio-economic costs and benefits are normally considered and the overall objective is in principle to maximize total socio economic surplus which is the sum of the consumer and producer surplus. Figure 2-2 shows the consumer and producer surplus relationship with the electricity market price.

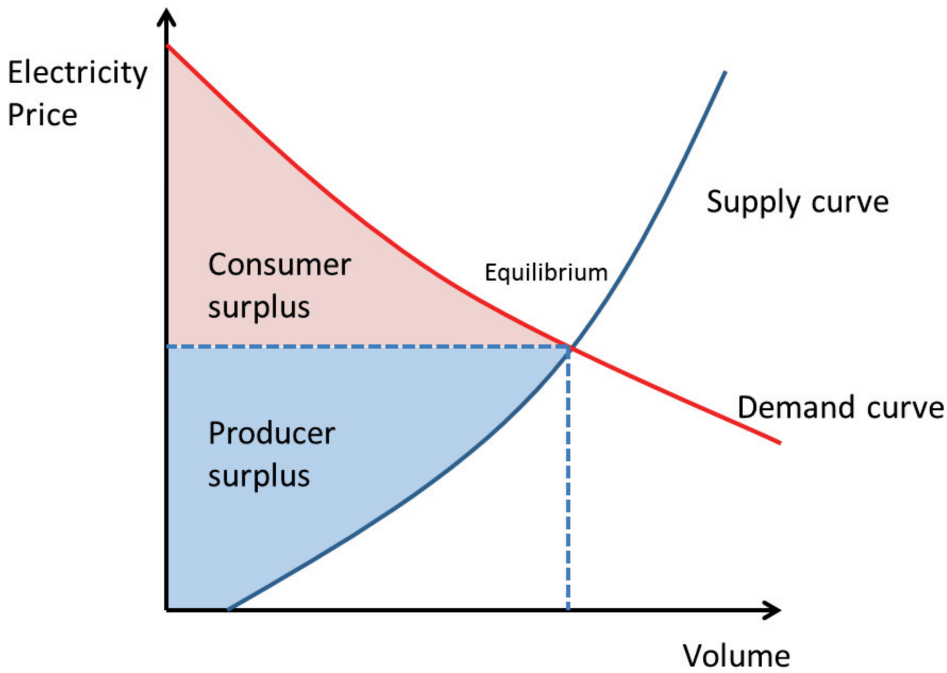


Figure 2-2 Supply demand curve

The final step in this phase also includes a comparison and ranking of the use cases (alternatives) based on their socio economic performance (economic optimization) over the planning horizon by estimating the total net present values for all use cases.

Often *expectation values* for the different cost elements are used in this phase, which means that the optimization is based on the most probable future outcomes or scenarios. If uncertainties are not explicitly dealt with in this stage, they should be considered as described in the next paragraph.

Evaluate risks and uncertainties

Any decision where future performance is involved has some uncertainty due to lack of complete knowledge about possible future outcomes. This fact is a source of risk and needs to be considered. The different alternatives (use cases) should thus be analyzed with respect to risk by performing some kind of risk analysis process.

A simple approach for uncertainty treatment is to perform a sensitivity analysis:

1. Describe the uncertainties of the cost elements in the objective function by specifying pessimistic and optimistic values for the different cost element.
2. Evaluate the impact on use case socio-economic performance and ranking using the pessimistic and optimistic values for the different cost elements estimated in step 1.
3. Evaluate possible risk reduction measures (extra investments) that might make the use cases more robust and estimate socio economic consequences and ranking impact.
4. Document sensitivity analysis findings.

Overall evaluation – Selection of use cases/alternatives

The next step comprises a final evaluation, ranking and selection of the use cases to be implemented, given a set of (the most credible) assumptions. The preferred alternatives are those that minimize total socio economic costs or maximize total socio economic benefits and perform well enough in all scenarios. The final evaluation may also include additional information, as for example non-monetary consequences that have not explicitly been included in the economic analysis, e.g. quality of supply, environmental or other social considerations.

Monitor and evaluate results

To improve future planning and decisions, it is recommended to monitor performance of the implemented use cases over time to evaluate to which degree the expectations are met.

For all major developments/changes in the network there are also specific requirements for impact assessments describing the effects on the environment, natural resources and society.

The development of a new overhead power line could in addition to investment, operating and maintenance costs, contribute to reducing costs of losses, interruptions and bottlenecks. Non-quantifiable effects can e.g. be connected to seizure of land and deterioration of cultural landscapes. Non-quantifiable effects can also be positive like e.g. employment and business development. Although some effects are non-quantifiable, it is still appropriate to make a systematic assessment of these effects since they are part of the overall picture of the project's effects.

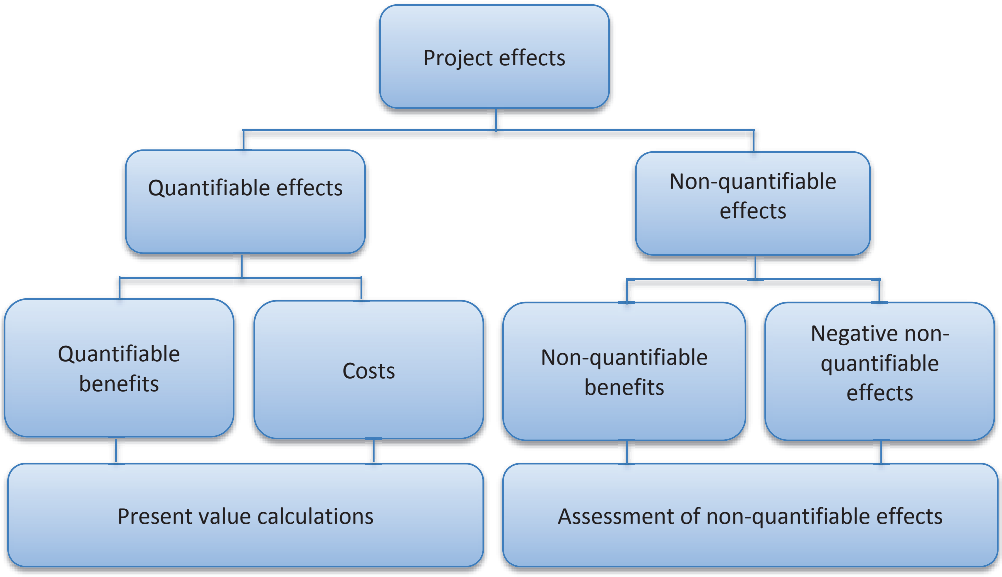


Figure 2-3 Assessment of the effects from a project/measure in economic analyses [14]

Planning and long-term development of the power grid is a complex task. Measures in the network must be seen in the context of development in other parts of the power system, such as the establishment of new generation/load and measures aimed at end users. Energy and power forecasting will provide important information for the network planner about expected development in the area.

2.2.2 Problem formulations – objective functions

As indicated in Figure 2-1 the first step in a socio-economic analysis is to describe objectives and goals. Decision criteria need to be formulated as a tool to choose among alternatives. An object function is a mathematical formulation of such a criterion.

One definition of the term *objective function* is:

> A function associated with an optimization problem which determines how good a solution is.

An objective function is for instance:

> Maximize total socio-economic return on Smart Grid investments.

The corresponding objective function in mathematical terms could e.g. be on the form:

$$\boldsymbol{Max\ W} = \boldsymbol{a}(\boldsymbol{x}) + \boldsymbol{b}(\boldsymbol{x}) + \boldsymbol{c}(\boldsymbol{x}) + \boldsymbol{d}(\boldsymbol{x}) - \boldsymbol{I}(\boldsymbol{x}) \qquad (2\text{-}1)$$

Where

- a(**x**) - Economic benefits
- b(**x**) - Environmental benefits
- c(**x**) - Quality of supply benefits
- d(**x**) - Safety benefits
- I(**x**) - Investment costs
- **x** - Vector with decision variables (x_1, x_2, ...x_n)

A decision variable x_i could e.g. be the capacity of a power line from A to B.

In practical cases it is often difficult, if not impossible, to evaluate all effects of a project in monetary terms – and different effects although cost-allocated, might have different weight and different uncertainties that make them difficult to include straight forward in an overall total cost-benefit analysis. Two different approaches can be used to overcome this difficulty:

- To include certain effects as restrictions in the objective function
- To use a multi criteria approach

An example of including restrictions in the objective function could e.g. be that the voltage drop when deciding the capacity of a power line from A to B, should not be larger than 10 %. This means that if the alternative with the lowest costs does not meet this restriction, it will not be a qualified alternative.

Multi-Criteria Decision Analysis (MCDA) is the discipline that studies methods and procedures by which concerns about multiple conflicting criteria can be formally incorporated into the management planning process. The use of MCDA in use case decision making is justified by the simple fact that not all aspects that matter (and must be considered) can be given a monetary value. When using MCDA light can be shed on which trade-offs, uncertainties and value judgements are crucial to the decision and which issues that do not matter. A practical example on using MCDA in DSO decision making can be found in [15].

Regardless of approach to design a pertinent objective function, a set of performance indicators is needed. A performance indicator is a parameter which provides information about performance. The most important performance indicators for organizations or processes are often labelled as Key Performance Indicators (KPIs). As an example Cost of Energy Not Supplied (CENS – or KILE in Norwegian) is a KPI for the TSO and the DSOs in Norway with respect to power system reliability.

The performance indicators used in a decision making process will directly or indirectly be a part of the objective function. Thus, for the evaluation of Smart Grid use cases both socio-economic decision criteria and corresponding performance indicators are needed. As decision makers also need to evaluate corporate economic consequences, similar criteria and performance indicators might be formulated from corporate economic perspective. One could state that it is the role of the regulator to ensure that socio-economic and corporate decision making criteria are corresponding to avoid conflicts in ranking of use cases. One example of such a regulatory intervention is the use of penalty schemes for customer interruptions. Before the CENS arrangement was introduced as a part of the income cap regulation in Norway, the TSO and the DSOs did not see customer interruption costs as a part of their corporate accounts. After the introduction of the CENS arrangement, such costs are included as a part of the utility corporate costs.

2.3 Risk

Risk is often defined as the possibility that the actual results differ from the expected results, and are usually indicated as a measure of dispersion as standard deviation or variance. Risk can be divided in two groups:

- Systematic risk is related to the development in central macroeconomic variables like e.g. interest level, inflation, exchange rates and tax rules.
- Unsystematic risk is related to specific aspects of individual projects. Poor project management and/or inaccurate forecasting may lead to time delays, cost overruns or reduced utility value.

The most common way to take into account of risk today is through an addition in the discount rate. The discount rate is normally considered to be constant during the analysis period. This means that the uncertainty is assumed to increase steadily in time. Since the unsystematic risk is diversifiable, i.e. that it can be eliminated by investing in many different securities/projects, the discount rate will only compensate for systematic risk.

A distribution utility will also be exposed for risks related to unwanted events, i.e. damage to people, equipment, environment or reputation. This type of risk is not priced in the market and is difficult to value. A common method to express this type of risk is through the parameters probability and consequence:

$$\textit{Risk = Probability x Consequence} \qquad (2\text{-}2)$$

The risk can thus be reduced by reducing the probability and/or consequences associated with an incident. The risk can i.e. be illustrated in a risk matrix, which shows the combination of probability and consequences for certain incidents. The scale can be quantitative or qualitative. Figure 2-4 shows an example of a risk matrix. Incidents with high risk will be found in the upper right part of the matrix (red area), while incidents associated with low risk will be found in the lower left part of the matrix.

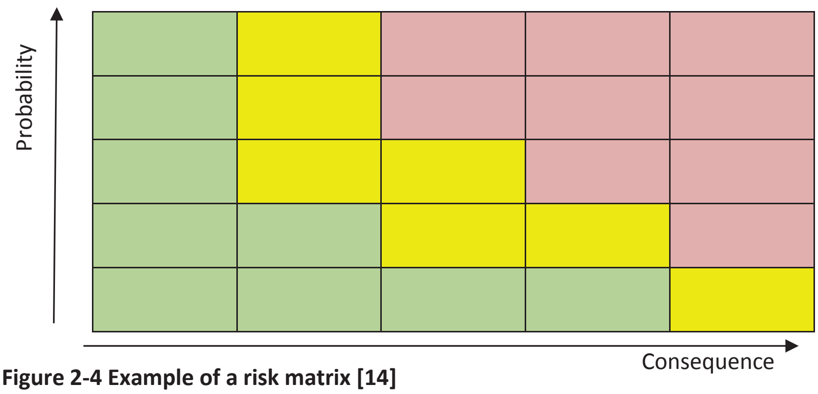


Figure 2-4 Example of a risk matrix [14]

Some consequences related to disruptions like CENS and repair costs, can relatively easily be expressed in currency units. Other consequences, such as personal injuries and damage to environment and reputation, are difficult to put a value on. It is also a challenge to estimate the probability of various incidents.

2.4 Sensitivity- and scenario analyses

When calculating the present value of various investments, it is appropriate to carry out sensitivity analyses and/or scenario analyses in order to highlight the uncertainty associated with the investment. Such analyses involve changing the key assumptions / parameters and study how this affects the socio-economic profitability.

A present value analysis usually includes a number of factors and both probability of discrepancies and to what extent this affects the probability calculation, will vary. Table 2-1 shows an example of classification of different factors included in profitability analysis. The focus for further investigations should be put on factors located in group 1 since both probability and consequences associated with deviation is high. A small change in these factors might change the result from the profitability analysis. Similarly, changes in factors located in group 4 will have less effect on the profitability analysis and do not need further investigations.

Table 2-1 Classification of factors of uncertainty [14]

		Probability of deviation	
		High	**Low**
Sensitivity to deviation	**High**	1	2
	Low	3	4

The profitability calculations are usually done with a safety margin by using a high estimate for the investment costs and a low estimate for the expected benefits of the investment.

Some factors included in the profitability evaluation might be correlated to each other. Such correlations must be included in the sensitivity analysis, and this makes the uncertainty picture more complex.

Scenario analyses are usually a bit “wider” than sensitivity analyses. Scenario analyses may involve different trends, extrapolations of development of consumption and generation in an area, assessment of various parameters, i.e. increased environmental focus in national policies, technological advances etc. The scenarios can be developed using detailed computer models, or consist of simple “what if” questions [14].

3 Distribution system planning - Today's deterministic methodology

Distribution networks in Norway are, in general, designed to cope with the worst-case scenario of the expected peak load and in a way that minimum or no active operation intervention is required. This approach, known as "fit and forget", is carried out in a deterministic way, i.e. without taking probabilities of different event sequences into account. Although sensitivity analysis and risk analysis are performed today, the method is still deterministic. Sensitivity analysis are testing the robustness of the result of a model in the presence of uncertainty in its inputs. Risk analysis results in a qualitative evaluation of the risk of some chosen events.

Figure 3-1 presents a generic flow chart that resembles this deterministic methodology (the figure is based on a figure found in [11]). Once a planning study is defined and load models for the planning horizon are made, different planning alternatives to be considered must be generated. The planning alternatives are then technically analyzed to see if they are technically feasible or not. If one alternative violates technical constraints, network reinforcement /expansions are applied to the alternative. If the alternative is technically feasible then the corresponding costs are evaluated. The most cost-effective planning alternative will likely be the final adopted solution.

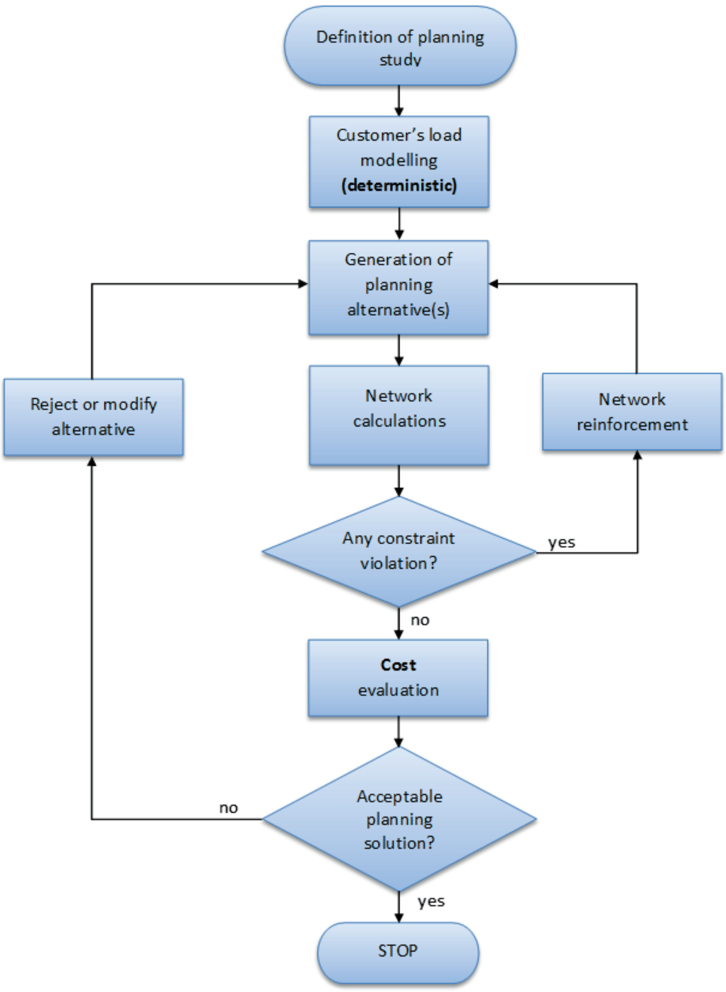


Figure 3-1 Deterministic planning methodology for electrical networks (based on figure found in [11])

The systematic approach is general and can be used in power system planning, operational planning, maintenance and reinvestment planning. For other planning purposes than power system planning, some of the elements in Figure 3-1 might be disregarded.

The elements in Figure 3-1 are discussed briefly below.

Definition of planning study
Establish the motivation for the analysis. Power system planning is an element in finding out how to cover the need for grid capacity or how to solve a problem in the power system. A problem can be defined as the gap between current situation and the desired situation:

Problem = "Desired situation" – "Current situation" (3-1)

A successful problem solving is based on a well-defined problem formulation. This means that one basically should use some resources to:

- Establish an overview of the planning area situation
- Identify and describe the problem
- Clarify which parts of the network that are affected – determine system boundaries
- Describe objectives and criteria
- Consider the time horizon for the analysis
- Consider which analyzes and simulations that basically should be carried out and with what accuracy (modelling depth)
- Clarify terminology

Socio-economic analyses are used to assess whether measures should be implemented or not, as discussed in Chapter 2.2. The cost-minimizing criteria can often be used directly, but in some cases a more simplified criteria will be more convenient. Bottleneck costs e.g. are most relevant for voltages from 132 kV and above and not so relevant for the lower voltages.

Modelling of customer's load and generation
The purpose of the power system is to connect power generation and consumption. The whole power system planning is based on knowledge and information about loads and generation connected to the grid. Key parameters in distribution system planning are:

- The peak load and peak generation (active power and reactive power with an hourly resolution)
- Variation in loads and generation over the year and day
- Future developments – forecasts

The quality of information about loads and generation is essential for the technical analysis of alternatives. Differences between estimated (calculated) and real load flow might lead to over- or underinvestment in the grid.

This traditional representation is used in distribution network planning studies by assuming unique yearly values for demand and generation (if present and with constant/predictable output). Peak values are calculated to classify worst-case operation conditions. The peak values are used (together with a constant yearly growth rate) in the deterministic fit-and-forget approach to plan network expansion for a predefined planning period (Table 9-2). Average values are considered for estimating technical losses as well as for reliability analyses.

Traditionally, recorded consumptions are read manually and with low periodicity, and almost all the MV/LV substations are non-observable. Therefore, in today's planning methodology loads are usually allocated to standard types of load (e.g. household, farm, industry, office, etc.) represented by their typical load estimation parameters e.g. utilization times, Velander coefficients (to produce suitable approximations of the peak demands, starting form yearly energy consumption), and standard variation curves for year and day (see Figure 3-2 and Figure 3-3). The models are deterministic, i.e. without any description of random variations. In such models, a given input will always produce the same output. For planning purposes there are often only two worst-case situations considered:

- Minimum (summer) demand with maximum generation.
- Maximum (peak or winter) demand without generation.

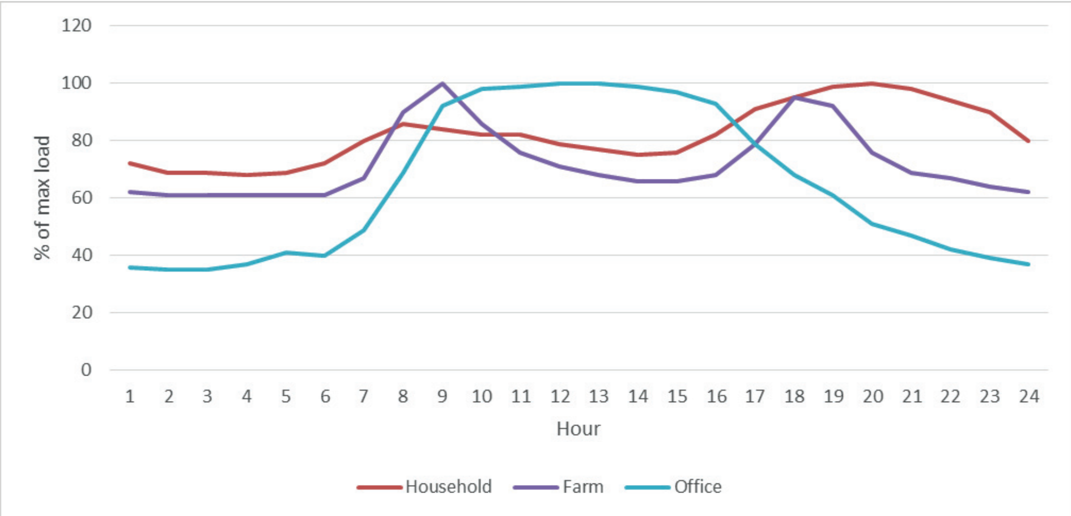


Figure 3-2 Example of standard daily variation curves (Norwegian)

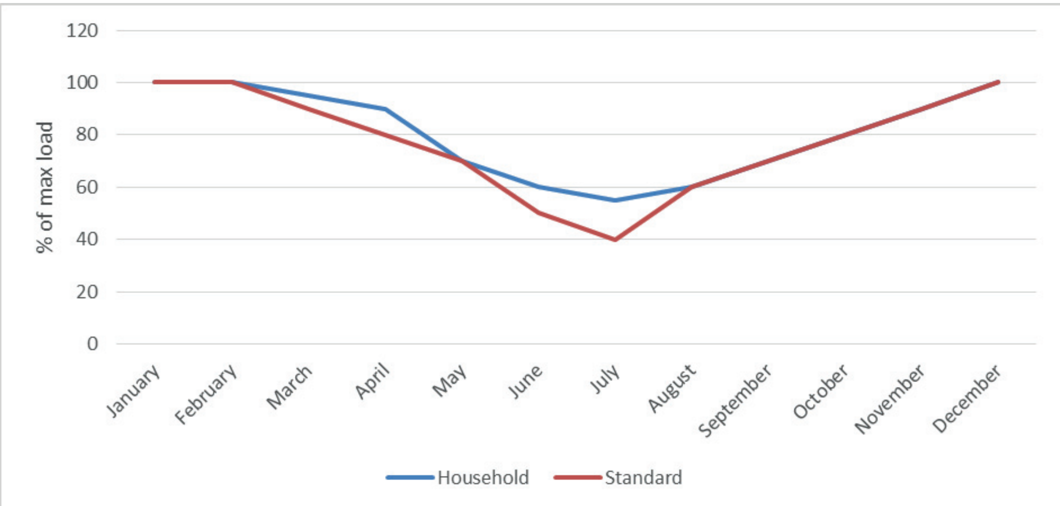


Figure 3-3 Example of standard yearly variation curves (Norwegian)

The Standard load variation curve in Figure 3-3 is an average variation curves used when the load comprises several load categories, and is used when e.g. an aggregated load represents a complete LV network with a large number of individual loads.

Generation of planning alternative(s)
There are often several alternative solutions in distribution system planning. To keep the existing grid i.e. the do nothing alternative, will normally be a reference alternative. Analyses are often triggered by the fact that the existing grid no longer is good enough or that it can be improved, thus the generation of new alternatives process is seeking to identify alternatives that have the potential to enhance distribution system performance. If any new generation or consumption should be connected to the grid, it will often be obvious that today's grid must be reinforced due to the lack of sufficient capacity.

As indicated in Figure 3-1, the number of alternatives to consider will be dynamic, based on the experience gained through the planning process. Results of different analyses and evaluations will provide ideas for new alternatives and reasons to discard alternatives that are not good enough. This is shown by the feedback loops in Figure 3-1.

Network calculations
In order to evaluate the different alternatives, they must be analyzed. Both technical and reliability analyses must be performed to find the properties important for comparison and ranking of the alternatives. Examples of technical analyses can be calculating the electrical conditions using load flow and short circuit calculations. The results from these technical analyses serves three purposes:

a) They provide a basis for checking if the alternatives satisfy the technical restrictions. If e.g. the voltage conditions in one alternative do not satisfy the power quality requirements (given in Standard EN 50160[2] or any national power quality regulation), the alternative must be modified or discarded.
b) They provide a basis for the establishment of operational costs (OPEX). For example, information about the network losses is used as input when calculating cost of losses for the alternative.
c) They give ideas for new alternatives. If the technical analysis shows that e.g. a power line will be overloaded, it will be a natural alternative to increase the capacity for this power line.

There are several analytical tools that support the planning process:
- Load flow analyses
- Short circuit analyses
- Reliability analyses
- Risk analyses
- Power quality analyses
- Dynamic analyses (stability etc.)

Costs evaluation
In a technical economic analysis the economic characteristics of the different alternatives play a central role. Establishing the cost basis for the different alternatives comprises the following cost elements:
- Investment costs
- Network losses costs
- Environmental costs
- Interruption costs
- Congestion costs
- Operating costs
- Maintenance costs

[2] EN 50160 – Voltage Characteristics of Public Distribution Systems

Depending on the purpose of the analysis, various cost elements are relevant. Not all cost elements mentioned above are of interest in all analyses. Some costs are fixed (e.g. CAPEX, investment cost) and some depend on the operating conditions (e.g. OPEX, network loss cost).

When the different costs for the qualified alternatives are available, the task is to evaluate and find the most economically alternatives. This means primarily to identify the measures (alternative) which helps to minimize the overall cost.

The solution of the general planning problem assumes that overall costs are analyzed (summed) over a number of years (the analysis period) for all possible combinations of measures and time of implementation. The economic analysis is thereby providing a basis for determining what measures to implement and when they should be implemented.

The problem is thus to select the optimal "itinerary" through the analysis period, and "visit" the right alternative in each time interval as illustrated in Figure 3-4.

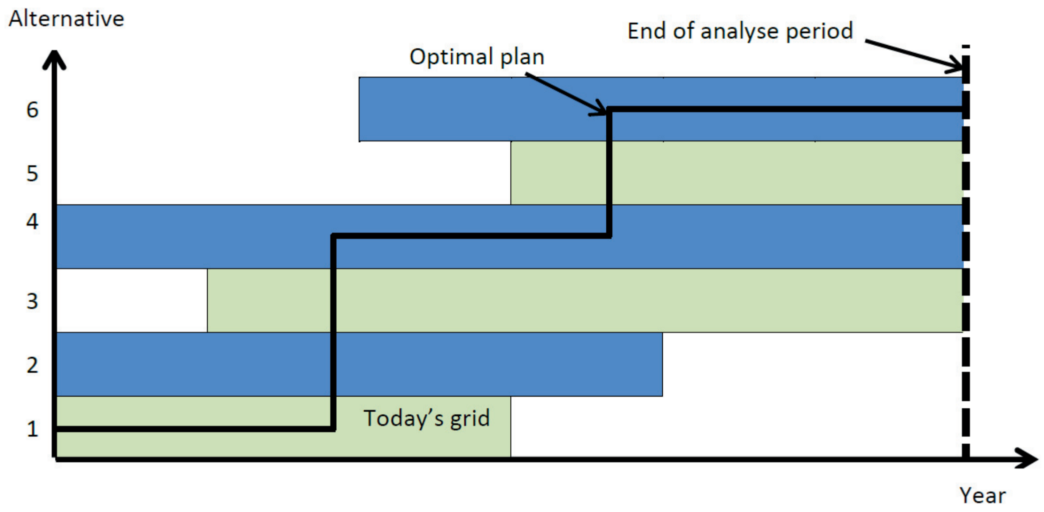


Figure 3-4 Example of a development plan

Overall evaluation

This is an evaluation phase where the economically most beneficial plans are selected. The evaluation is based on:

- Uncertainty in the underlying data (often with the help of **sensitivity analysis**)
- Elements that are not directly represented in the economic analysis model (it is not possible to put a cost to all aspects)
- How flexible the different plans are regarding uncertainty in the underlying data

The result from this evaluation will be a proposal for new measures to be taken and when they should be implemented.

4 Today's method for load and generation modelling on LV networks without data from smart meters

In network calculations like load flow and short circuit calculations, loads and generation must be modelled (active power and reactive power). In Norway, most customers have so far read the electricity consumption (in kWh) manually one to twelve times a year. Only consumers with yearly consumption >100 000 kWh/h have automatic meter reading installed and the consumption metered every hour (kWh/h). This means that the distribution system operators (DSOs) have limited information about how the consumption (in kWh/h) actually varies in time for the smaller consumers (< 100.000 kWh/year) and hence concerning the actual load flow in the grid.

Every generation/power station connected to the electrical grid in Norway has, as a general rule, installed automatic meter reading independent of the size of the power station.

4.1 Load modelling

Figure 4-1 illustrates the load modelling process today.

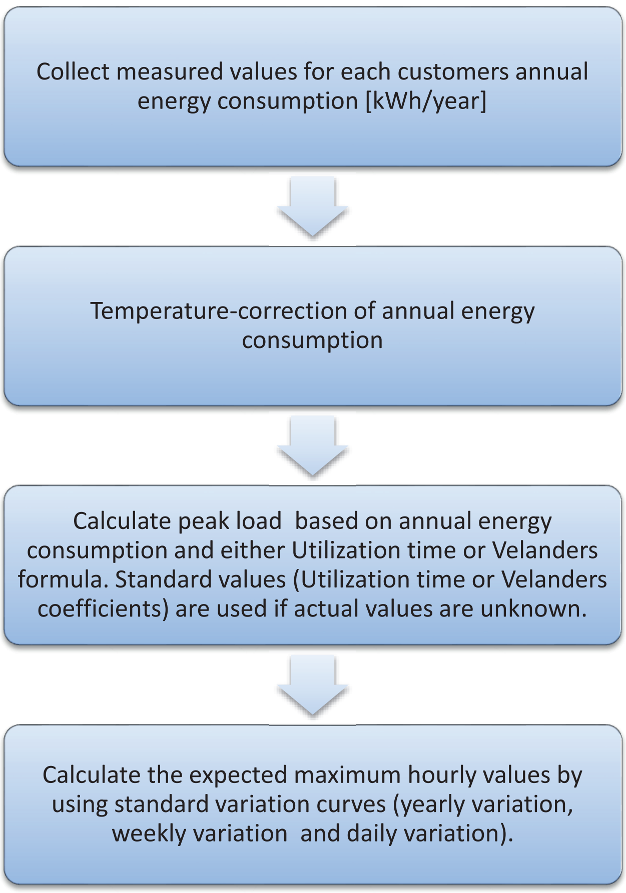


Figure 4-1 Flow-chart - Load modelling today without the use of data from smart meters [14]

The energy consumption in Norway is significantly affected by weather and climate conditions as electricity is the dominant energy carrier for space heating. When analyzing the energy consumption, it is thus important to adjust the data for the influence of these varying conditions.

Based on information about consumer category (household, office building, industry, agriculture, etc.) and annual electricity consumption, the DSO calculates/estimates the peak load in kW for each consumer or group of consumers. The transformation from annual energy consumption in kWh/year to peak load in kW and kVAr is usually done by one of these two methods:

- Using standard values for Utilization time (T_u) and Power Factor ($\cos\varphi$). This method can be used for both LV and MV distribution grids and is described in chapter 4.3
- Using the Velander formula ($P_{peak} = k_1 \cdot W + k_2\sqrt{W}$). This method can be used for LV distribution grids and is described in chapter 4.4.

4.2 Temperature correction of annual energy consumption

In many sectors the energy consumption rises in cold winter months and decreases as the temperature rise during warmer summer months. Temperature variations between years might result in significant fluctuations in the annual energy consumption. When analyzing the energy consumption, it is often useful to adjust the data for the influence of temperature and possibly other weather conditions. Such corrections are made in Norway using different methods and data.

One common method for temperature correction of annual energy consumption is described in [14]. The method adjusts and refers every yearly value to the normal temperature:

$$W_{i,\,temp.corr.} = W_i \cdot \left\{(1-k) + \, k \cdot \frac{HDD_{normal}}{HDD_i})\right\} \qquad (4\text{-}1)$$

Where:

- W_i = yearly energy consumption, year "i"
- k = Temperature dependent part of the yearly energy consumption (in %)
- HDD_{normal} = Heating Degree Days for a normal year
- HDD_i = Heating Degree Days for year "i"

Not all of the energy consumption is dependent of the outdoor temperature. Energy used for lighting, cooking and normal household appliances (TV, computers, refrigerator, freezer, washing machine, dishwasher, etc.) are not temperature dependent. Energy used for space heating is very temperature dependent, and Norway is one of the few countries where electricity is the main energy source. About 73 % of the households in Norway use electricity for space heating (electric heaters, heating cables and air-air heat pumps). About 12 % of the Norwegian households use firewood as their main source for space heating (source: www.ssb.no).

Heating Degree Days (HDD) is a measure of the heating demand. HDD is the difference between the daily mean temperature and a base temperature, which is 17 °C. For example, if the mean temperature for one day is 10 degrees, the heating degree that day is 17-10=7. Negative heating degrees are set to zero. The sum of heating degrees for a year makes the HDD for that year. The higher HDD, the colder year.

Heating Degree Days are measured and calculated annually by The Norwegian Meteorological Institute (DNMI). There are about 340 monitoring stations in Norway and about 510 geographical locations calculated. The norm is defined as the average HDD for a 30 years period (1961-1990).

4.3 Calculating peak load by using "Utilization time"

One method to estimate the annual peak load (P) is to use estimated Utilization time (T_u) for the different consumer categories and the consumer's annual energy consumption (W):

$$P_{peak} = \frac{W_{year}}{T_u} \qquad (4\text{-}2)$$

Table 4-1 Examples of standard Utilization times used in NTE Nett

Consumer category	Utilization time (h)
Household	3600
School	2500
Health and social care	3800
Office	3800
Retail store	4100
Farm	3000

Figure 4-2 illustrates the Utilization time. The red curve (P) shows the distribution of the load during a year (8760 hours). The red area equals the annual energy consumption. The blue area gives the same annual energy consumption but with peak load (14,5 kW) during the utilization time T_u = 2900 hours.

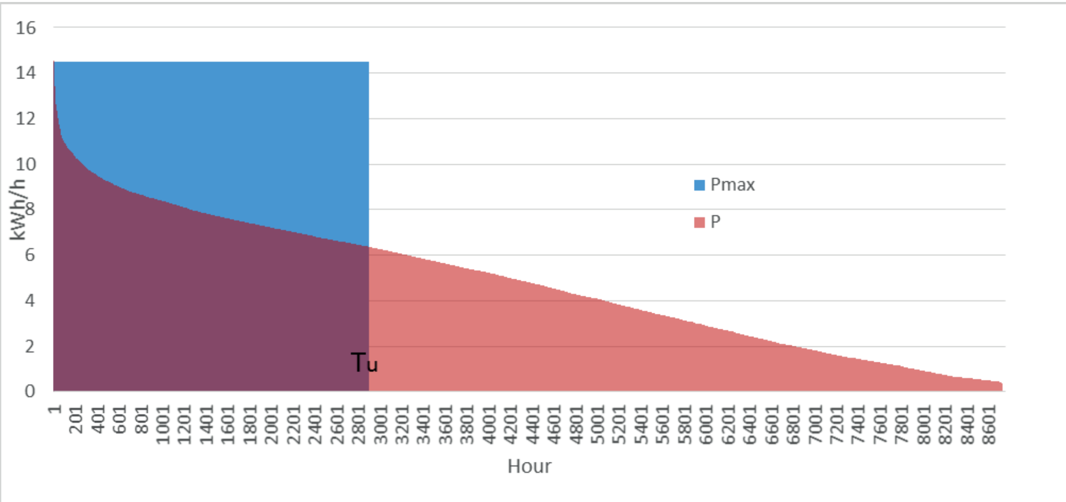


Figure 4-2 Utilization time (T_u)

4.4 Calculating peak load by using the Velander Formula

The Velander formula is a method that estimates the annual peak load for an electricity consumer, based on the consumer's annual energy consumption. The Velander formula is based on the Gaussian case and presumes that the loads are normally distributed, independent of each other and more or less similar. These assumptions are reasonable during peak load.

The Velander formula:

$$P_{peak} = k_1 \cdot W + k_2\sqrt{W} \qquad (4\text{-}3)$$

Where

- P_{peak} = Peak load during the year
- W = Annual energy consumption
- $k1, k2$ = Constants valid for a particular type of load in a particular environment, and must be determined by measurements

Table 4-2 shows example of Velander constants for different consumer categories calculated for a region in Norway during a dimensioning (cold) year.[3]

Since the formula is based on the assumption that the peak loads for the different consumers are normally distributed and independent of each other, the formula is best suited for load peak estimation of consumers in similar load categories. When aggregating groups where the peak loads occur at different times, the final result may be misleading. This is illustrated in Figure 4-3.

Table 4-2 Example of Velander constants calculated for a region in Norway [14]

Consumer category	k1	k2	Utilization time for one single customer [h]	Utilization time for several customers [h]
Detached house	0,000237	0,0119	3200	4200
Townhouses	0,000235	0,0116	3100	4250
Apartment building	0,000264	0,0140	2150	3900
School	0,000410	0,1750	1600	2350
Health and social care	0,000263	0,0790	3000	3800
Office	0,000270	0,0668	3000	3700
Retail store	0,000273	0,0655	2900	3650

The Velander formula is only used for loads connected to LV distribution networks, while utilization times can be used for loads in both LV and MV distribution networks.

[3] These utilization times do not correspond to the utilization times used in NTE, Table 4-1. They are calculated for a different area in Norway.

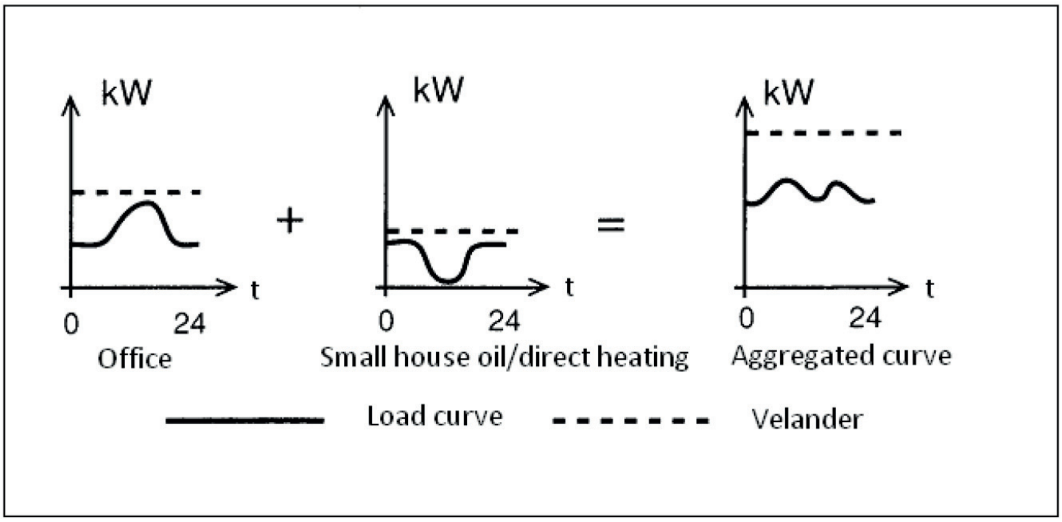


Figure 4-3 Comparison between actual power demand and Velander formula [16]

4.5 Standard load variation curves

Standard load variation curves for different consumer categories are used to estimate the load for each consumer at any time hour of the year. The load variation curves express the load as a percent of the peak-load:

- Monthly variation, load in % of maximum for each month of the year
- Daily variation, load in % of maximum for each hour of the day

Since standard load curves for different consumer categories are used, it means that every load in the same category have their peak load at the same time. In NTE Nett the same standard monthly variation curve is used for all categories, while daily variation curves are defined for 14 different load categories.

Figure 4-4 shows the standard monthly variation curve used on every consumer / load connected to the grid operated by NTE Nett. The curve is based on average variation for the total load in the grid (approximately 5 TWh/year). Figure 4-5, Figure 4-6 and Figure 4-7 show examples of daily variation curves used in NTE Nett for different load categories/customer groups. These curves represent typical load variation during a day for consumer categories in Norway and are based on historic measurement campaigns done by EFI (now SINTEF Energy) [17].

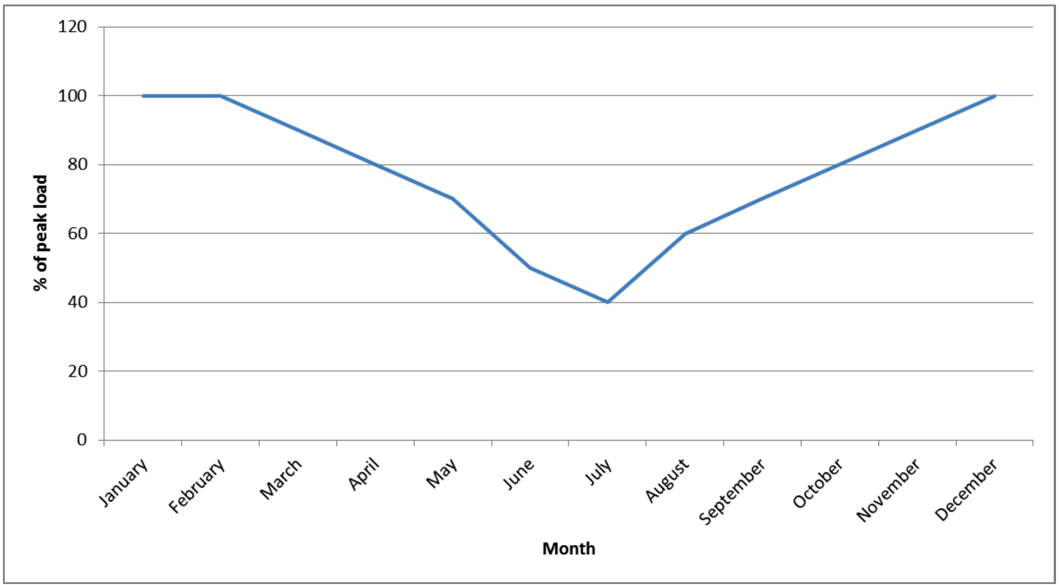


Figure 4-4 Example of the standard yearly variation curve used by NTE Nett

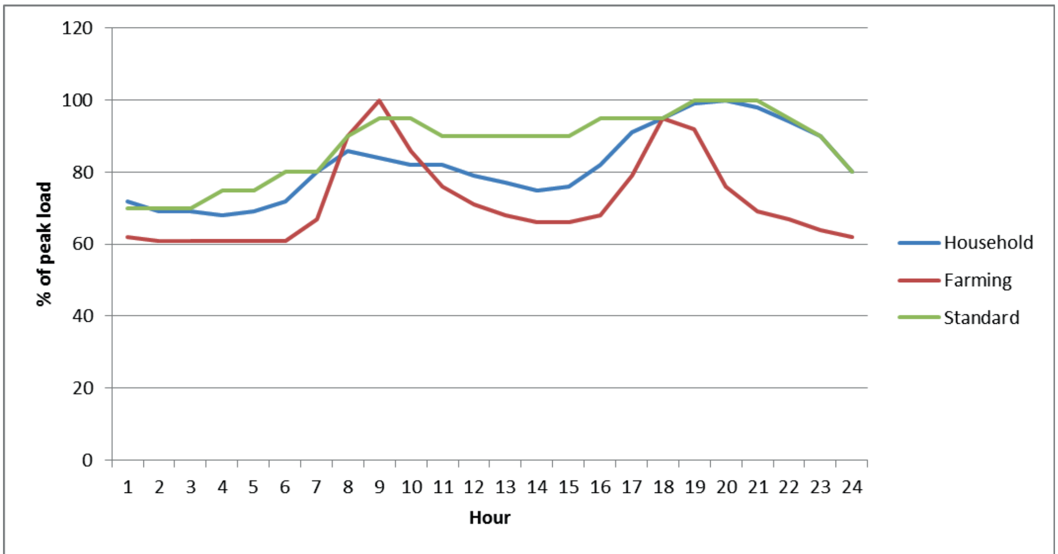


Figure 4-5 Example of daily variation curves used by NTE (1)

The Standard load variation curves in Figure 4-4 and Figure 4-5 are average variation curves used when the load comprises several load categories, and is used when e.g. an aggregated load represents a complete LV network with a large number of individual loads.

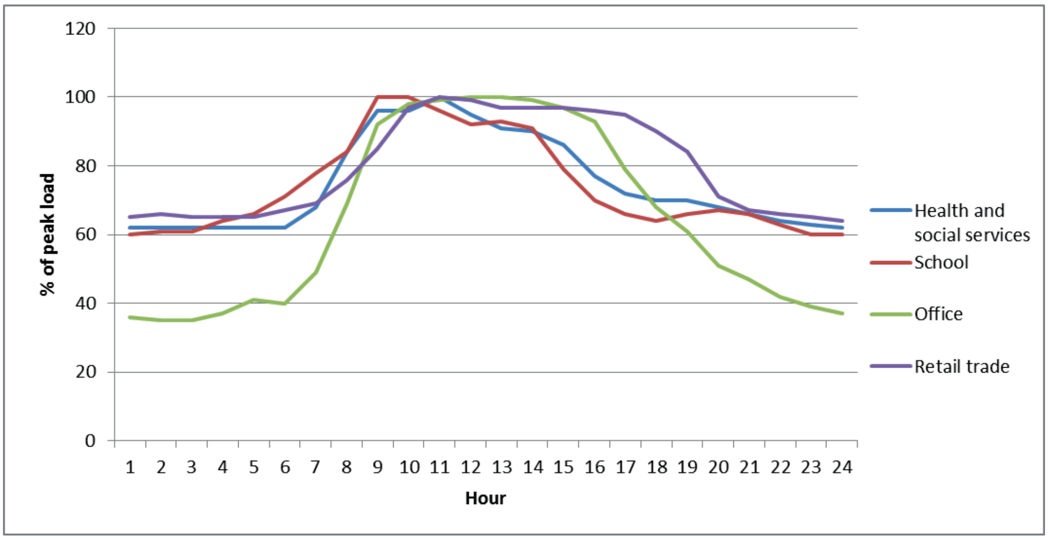


Figure 4-6 Example of daily variation curves used by NTE (2)

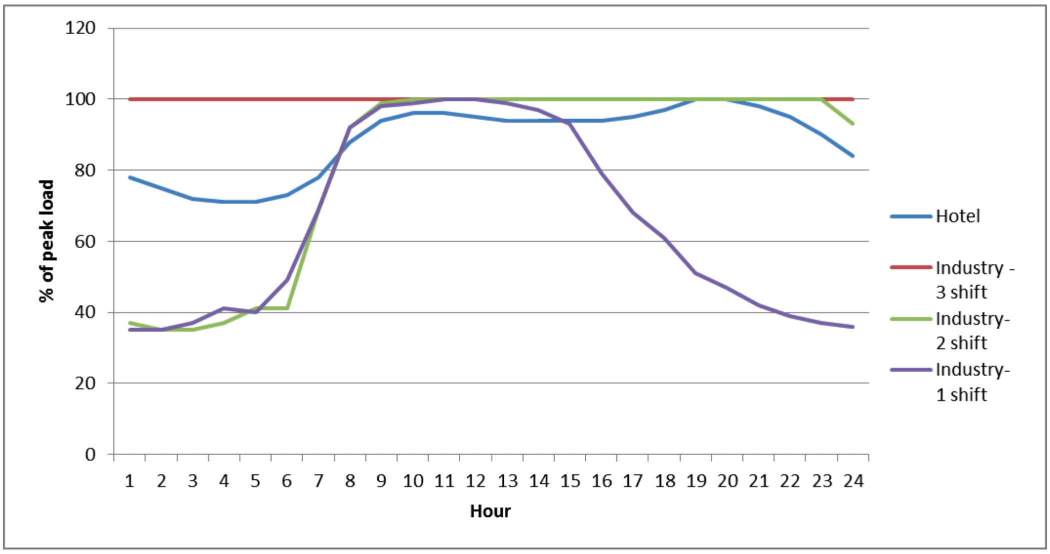


Figure 4-7 Example of daily variation curves used by NTE (3)

In Figure 4-7 the number notation of three different Industry-curves refer to the number of 8-hour work shifts used in the industry production.

By combining these standard load variation curves it is possible to calculate the load for every hour during a year and find the peak load during the year.

In addition to the time variation of the customer's demand, represented by the daily pattern, it exists also a systematic variation that appears as load growth over the years. The growth rate can be influenced by several factors, like social-economic changes and variations in the cost of fossil fuels or other energy sources. By using this prognosis for annual growth in energy consumption and/or maximum power (e.g. 0.5 % increase per year in annual energy consumption), the peak load in a future year can be calculated.

4.6 Comparison of calculated and metered load

Metered and calculated load for a few different loads are compared to see how today's load models and parameters used by NTE fits the real load. The loads are the same as used in the demo case in Chapter 11 and described in Table 11-2:

- Workshop
- Grocery store
- School
- Farm
- House 1
- House 2
- House 3
- Aggregated load

The metered values are temperature corrected according to the method described in Chapter 10.1.1. Two diagrams are presented for each load:

- One year (2014)
- One week in January, July and August 2014

Figure 4-8 and Figure 4-9 show aggregated load for the seven different loads. The blue curve is metered hourly values and the red curve is the corresponding calculated load. Figures between Figure 4-10 and Figure 4-16 show similar curves for the single loads.

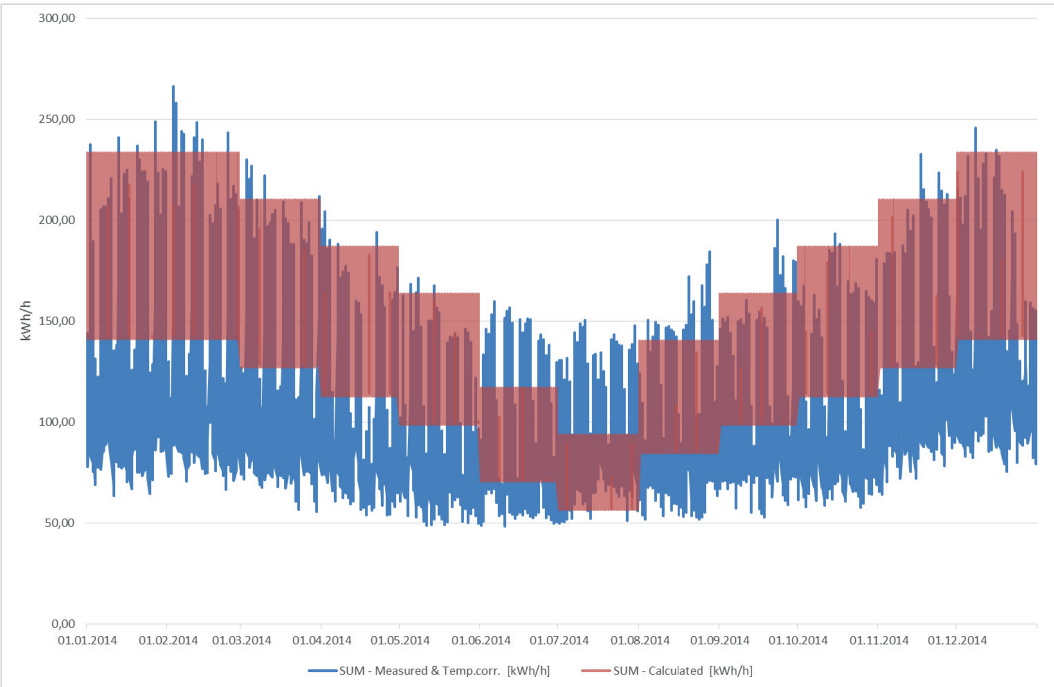


Figure 4-8 Aggregated load - Metered and calculated - for seven different loads during a year (2014)

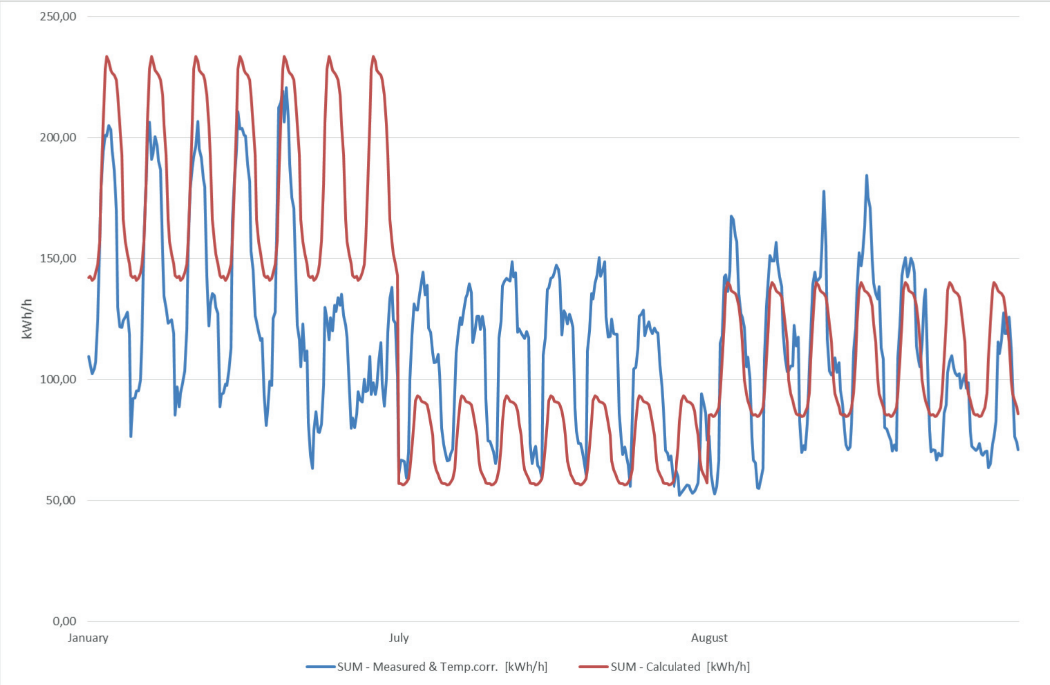


Figure 4-9 Aggregated load - Metered and calculated - for seven different loads during a week in January, July and August

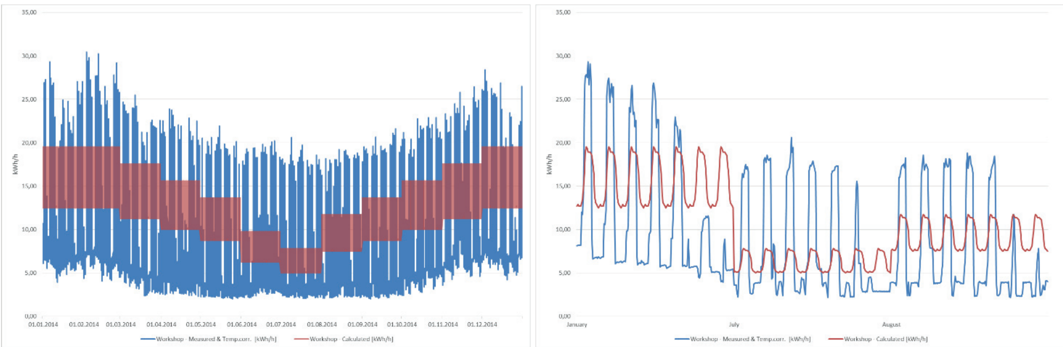


Figure 4-10 Metered and calculated load profiles for a workshop store during a year (2014) and a week in January, July and August

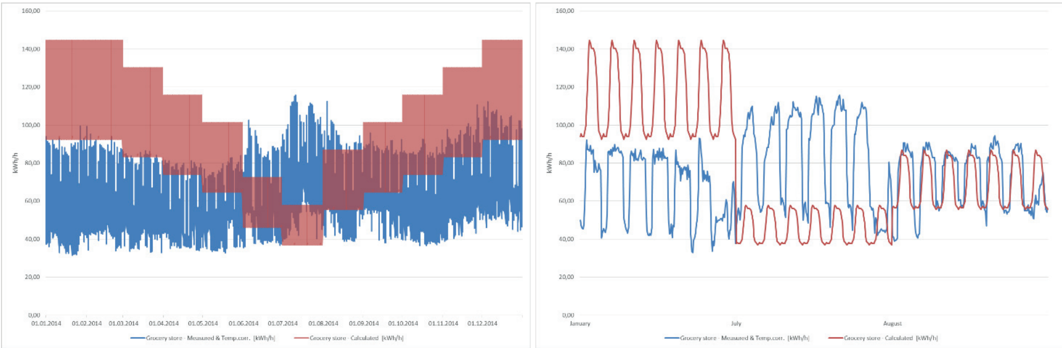


Figure 4-11 Metered and calculated load profiles for a grocery store during a year (2014) and a week in January, July and August

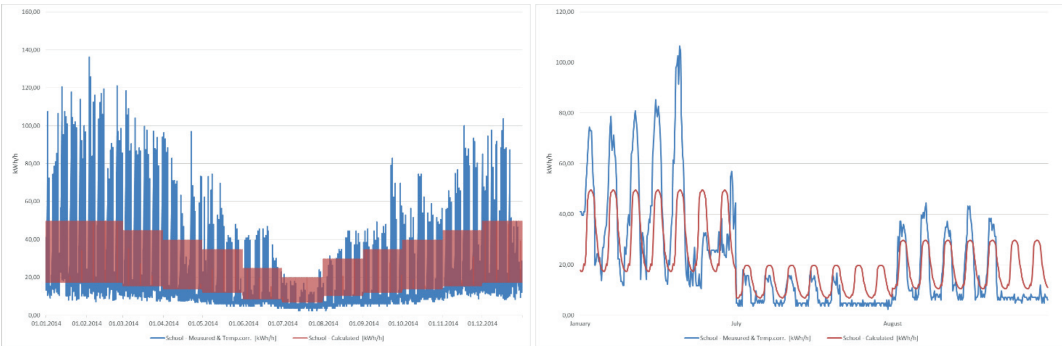


Figure 4-12 Metered and calculated load profiles for a school during a year (2014) and a week in January, July and August

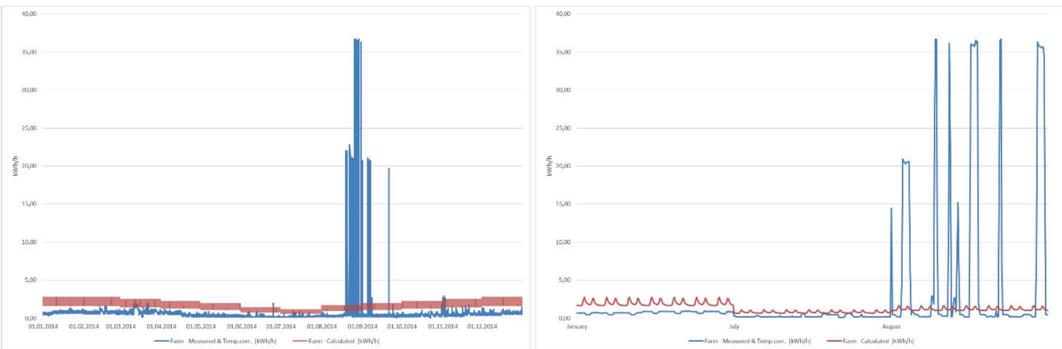


Figure 4-13 Metered and calculated load profiles for a farm during a year (2014) and a week in January, July and August

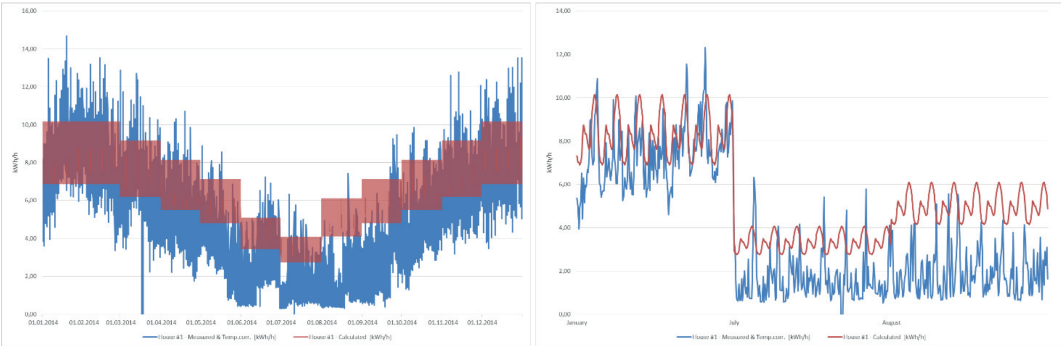


Figure 4-14 Metered and calculated load profiles for a detached house (1) during a year (2014) and a week in January, July and August

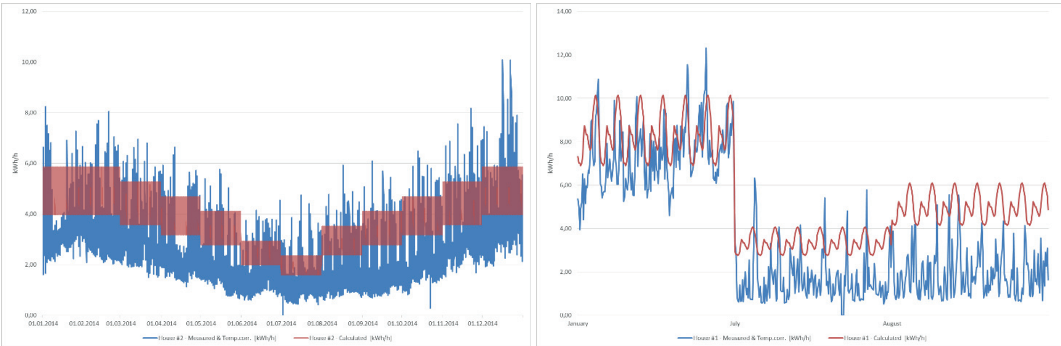


Figure 4-15 Metered and calculated load profiles for a detached house (2) during a year (2014) and a week in January, July and August

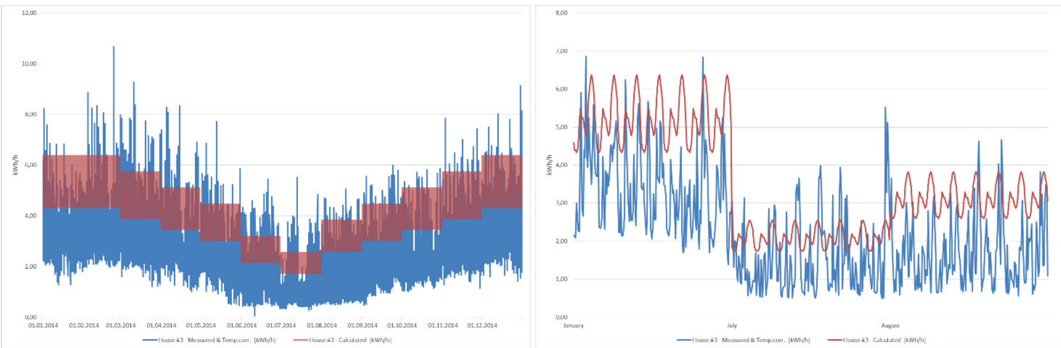


Figure 4-16 Metered and calculated load profiles for a detached house (3) during a year (2014) and a week in January, July and August

Aggregated load in Figure 4-8 and Figure 4-9 shows the largest correlation between measured and calculated values, while workshop, grocery store, school and farm show the smallest correlation. Common for them all, is that the real load is varying a lot more than the load model. The metered values for the grocery store in Figure 4-11 do not fit the standard yearly load variation curve. The real load does not vary particularly during the year. For the school in Figure 4-12 the real load is much higher in the winter (260 %) and lower in the summer when school is closed For the farm in Figure 4-13, there is a large deviation between real load and modelled load during the harvesting season in August- September.

Based on the results shown in the figures from Figure 4-8 to Figure 4-16, it is possible to make this conclusion:

Today's load modelling method with the use of standard utilization times and standard load variation curves for different load categories, does not necessarily describe the real load good enough. The real load tends to vary a lot more than the standard models, both stochastically and in range (minimum and maximum values). Special loads like the farm in Figure 4-13, show that individual load models should be calculated instead of using standard models. The stochastic character of the different loads should also be included in the load models.

4.7 Generation modelling

Generation in network calculations have in NTE Nett and other Norwegian utilities, traditionally been modelled as either maximum generation (installed capacity) or no generation. These two alternatives have been considered as probable in every load situation. Maximum and minimum generation combined with maximum and minimum load gives the extreme situations regarding the network load, and these situations are used when calculating load flow and other electrical quantities of the network.

According to the Norwegian regulation, the grid operator can only set temporary restrictions on generation from power-stations connected to the grid, pending future grid reinforcement. Other restrictions are not allowed. This means that any generator connected to the grid has unlimited access to generate up to the agreed limit (usually the installed capacity). In areas with bottleneck problems, producers can make their own agreement regarding generation restrictions without involving the grid operator.

PART II – Changing conditions for operating and planning of distribution grids

5 Conditions for operating and planning of electric distribution system are changing

The situation today:
The Norwegian distribution networks are traditionally, designed to cope with the worst-case scenario of the expected peak load and in a way that minimum or no active operation intervention is required ("fit and forget"). The need for increased transfer capacity has been met by grid reinforcement. The deterministic planning method is described in Chapter 3. Consequences of this reinforcement practice might be poor utilization of the grid capacity and consequently high costs.

The distribution networks have been dominated by passive elements (uncontrolled loads) and have relatively few active elements (generators and demand side management schemes). The variation in network load has followed almost the same pattern every year. The power flow has been mainly in one direction – from the feeding point to the connected consumers since there has been almost no distributed generation (DG) connected to the distribution grid.

The distribution system operators (DSOs) have no or very little information about the load situation out in the MV/LV distribution grids. Normally, only the voltage at the feeding point of the MV grid (the 22 kV bus bar in the feeding substation) is monitored. Thus, the voltages at the supply terminals to customers and the currents in cables and overhead lines must be estimated by performing e.g. load flow calculations to check compliance with the PQ code requirements.

RES:
The focus on climate change, renewable energy sources and energy efficiency during the last years, is about to make the situation more complex and unpredictable to the DSOs.

The generated power from renewable energy sources like solar, wind, wave, is unregulated and unpredictable. Integration of renewables into the electricity system as distributed generation (DG) is making the power flow more variable both in magnitude and direction. The distribution grids are normally not dimensioned for reverse power flows and integration of DGs often leads to protection problems and voltage quality problems.

Distributed generation (DG) in Norway today is mostly small hydro power plants in rural areas. These areas often have low grid capacity and low load. One example of such an area is Namsskogan [18]. In this 1416 km^2 area the maximum load is 1.2 MW (17.3 GWh/year, 900 inhabitants) and the potential for new DG is 73.6 MW (258 GWh/year). There is no extra capacity for integration of new generation in today's grid in this area. More than 8 million euro has to be invested in the grid in order to integrate all this production. Recently, also the interest for solar power has increased in Norway (see Figure 6-1 in Chapter 6.2). It is expected that the number of grid-connected photovoltaics in Norway will continue to grow in the coming years as well.

Energy efficiency:
The focus on energy efficiency and new environmental friendly appliances have resulted in a new type of loads that are energy efficient but often have a high power demand. These types of load will increase maximum network loading, but not necessarily the energy consumption. Here are some examples of new loads:

- Tank-less water heaters
- Electric Vehicles (EVs)
- Induction cookers
- Heat-pumps
- Power electronics controlled engines and pumps

Power quality:
About 40 to 50 % of the LV distribution network in Norway have an impedance higher than the EMC reference impedance defined by IEC [19] and [20]. One of the reasons for this is that most of the LV distribution grid in Norway is built as 230 V IT with isolated neutral. High impedance means that the network is weak and that customers might affect the voltage quality in their neighbourhood when using ordinary electrical appliances. When the power flow changes more frequent than before, it will affect the power quality negatively, e.g. by introducing flicker.

Energy storage systems (batteries) and automatic systems to control voltages and power flow will eventually be more commonly used in the distribution system to maintain a satisfactory power quality.

More accessible data
By 2019 every electricity meter in use in Norway shall be a smart meter [21]. These new meters can provide a lot of valuable information that the DSOs can use for power system planning purposes:

- Automatic hourly metering of load and generation
- Voltage quality registration (voltage level, hourly average, maximum and minimum)
- Load interruptions registration, (interrupted power and duration, energy not supplied (ENS))
- Earth-fault registration
- Fault localization information

Demand response:
Smart meters open new possibilities for consumers as well. They can achieve detailed online information about their own consumption, and can use this information to act more actively and control their own energy and power consumption. Smart homes, Zero- and Plus-energy homes will become more common, and energy/power controlling systems in these homes can be integrated with the smart meters.

Flexibility can be a trade commodity and Energy Service Companies (ESCO) may make agreements with many customers in order to aggregate and provide load flexibility in the electricity market or directly to the DSOs.

Smart Grids:
In order to handle RES, flexible loads, demand response (DR), demand side management (DSM), dispatchable loads, aggregators and smart homes efficiently, the distribution grids must be smart grids. Smart Grids technologies are relevant for reinvestment plans (when to reinvest), but have less relevance for power system planning (long term investment plans) [22].

Smart Grids deployment depends on the merging of ICT (information and communication technology) and the electric power system. Data from meters and sensors will be used real-time in controlling and operating the power system. Data security will be a very important issue. There will always be a risk that someone hacks into the systems and takes control and does some damage, e.g. disconnecting consumers/generation. This risk must be minimized in order to obtain a secure and sustainable electric power system.

Many new types of components will be introduced into the electric distribution system in connection with the transition to the Smart Grid (telecom, sensors, meters, PLC, power electronics, control systems, etc.) How will these new components affect the system reliability? Every system and component can fail. Advanced systems can increase the system reliability, but they can also reduce the system reliability if they are installed uncritically.

6 Renewable Energy Sources (RES)

Climate change is a defining challenge of our time [23]. Global awareness of the phenomenon is increasing and political action is underway to try and tackle the underlying causes, both at national and international levels. At the Paris climate conference (COP21) in December 2015, 195 countries adopted the first-ever universal, legally binding global climate deal named Paris Agreement [24].

The energy sector is by far the largest source of greenhouse-gas emissions and the second-largest source of CH_4 emissions after agriculture. Accordingly, energy has a crucial role to play in tackling climate change. Yet global energy consumption continues to increase, led by fossil fuels, which account for over 80% of global energy consumed, a share that has been increasing gradually since the mid-1990s.

Carbon pricing is gradually becoming established, and renewables have experienced strong growth and have established themselves as a vital part of the global energy mix. In many cases, they still require economic incentives and appropriate long-term regulatory support to compete effectively with fossil fuels. It is evident that if the energy sector is to play an important part in attaining the internationally adopted target to limit average global temperature increase, a transformation will be required in the relationship between economic development, energy consumption and greenhouse-gas emissions.

Achieving the target will require determined political commitment to fundamental change in our approach to producing and consuming energy. All facets of the energy sector, particularly power generation, will need to transform their carbon performance. Moreover, energy demand must be moderated through improved energy efficiency in vehicles, appliances, homes and industry. Deployment of new technologies, such as carbon capture and storage, will be essential. It shows that, to stay on an economically sustainable pathway, the rise in emissions from the energy sector needs to be halted and reversed *by 2020.*

Renewable Energy Sources (RES) are often praised as the most sustainable source of energy for two reasons:

- RES are, in principle, carbon-free. There are no direct CO_2 emissions associated with the deployment of non-biomass RES.
- The defining feature of renewables is that their resource potential does not deplete over time.

Moreover, the combined resource potential of all renewables exceeds the current energy demand by at least one order of magnitude. Given the constraints on fossil and nuclear fuel availability, and the limited social acceptance of nuclear waste and CO_2 storage, it seems likely that RES will become increasingly important in the long-term, even if climate policies remain weak.

On the other hand, future RES deployment may be limited by

a) the competition with other sources of energy
b) currently high costs
c) regional heterogeneity of resources (combined with limited transportability)
d) systems integration challenges.

Since there are more options for producing renewable electricity than non-electric energy, the RES contribution to climate change mitigation will also depend on the degree to which end-uses can be electrified, for instance by introducing electric vehicles [25].

Currently RES supplies about 24 % of global electricity demand.

The focus in this chapter is RES connected to the Norwegian distribution grids as distributed generation (DG). A more general presentation of RES is given in Appendix B.

6.1 Bioenergy

Bioenergy has always played an important role in the Norwegian energy supply. The total consumption of bioenergy in 2012 was about 16 TWh. About 45 percent of this is the use of firewood in households for heating.

Several reports show a significant potential for increased extraction of forest resources in Norway. NVE[4] indicated in 2011 that about 14 TWh more biomass will be possible to realize within a limit of 0.30 NOK/kWh, but require increased logging, thinning and utilization of branches and tops.

The most common application of bioenergy is generation of heat. It is also possible to produce electric power, liquid biofuel, biogas and hydrogen from biomass. Bioenergy is the oldest energy source and has been used for heating and cooking in all times. Bioenergy as fuel to DG connected to the distribution grid is not of particular interest today in Norway.

6.2 Direct Solar energy

Despite the fact that the solar irradiation in Norway is relatively low compared to more suitable places in the world, the potential for solar energy (both electricity and heat) is significantly. If 0.4‰ of Norway's land area were covered with photovoltaics, it would cover the total Norwegian domestic electricity consumption [26].

Norway may be suitable for utilization of solar energy for electricity (photovoltaics). One challenge with photovoltaics in Norway is that the demand for electricity is greatest in the winter when the insolation is at its lowest. Yet one of the reasons why many places in Norway are suitable for solar development is just cold and dry climate, which helps keep the operating temperature of the photovoltaics down and thus reduce both heat losses and wear on the photovoltaics. Overheating of the photovoltaics is a challenge in warmer climes.

Except from this, Norway's major hydropower resource is a significant advantage in a future major development of photovoltaics. Solar energy is a relatively **unpredictable source** and the output will vary considerably from day to day (cloudy or sunny) and season to season (large difference between summer and winter). Norway's great advantage is that solar energy can be used when the insolation is high while saving water in the reservoirs. When solar insolation is low, it is possible to compensate with hydropower. This is much cheaper than building large batteries for storing solar energy. Another advantage of building photovoltaic plants in Norway is that there are relatively much available land area and it is sparsely populated. Larger photovoltaic plants can be built without considerable conflicts with other land use.

2.2 MWp (megawatt-peak) new capacity of photovoltaics was installed in Norway during 2014 (see Figure 6-1). This is three times the year before and can be characterized as a turning point for photovoltaics in this country. 1.4 MWp of this new capacity was connected to the distribution grid.

Total accumulated photovoltaic capacity in Norway was 12.8 MWp in 2014 and is dominated by solar panels in private cottages and lighthouses. Accumulated capacity of grid connected systems is 1.7 MWp which gives an annual electricity generation of about 1.4 GWh [26].

Small and medium scale photovoltaic power plants connected to the Norwegian distribution grids has become a reality and the amount of PV power plants is increasing. During 2015 the accumulated photovoltaic capacity in Norway passed 15 MWp [27]. Because of its relatively unpredictable character, PVs connected to the distribution grids can be a challenge.

[4] Norwegian Water Resources and Energy Directorate

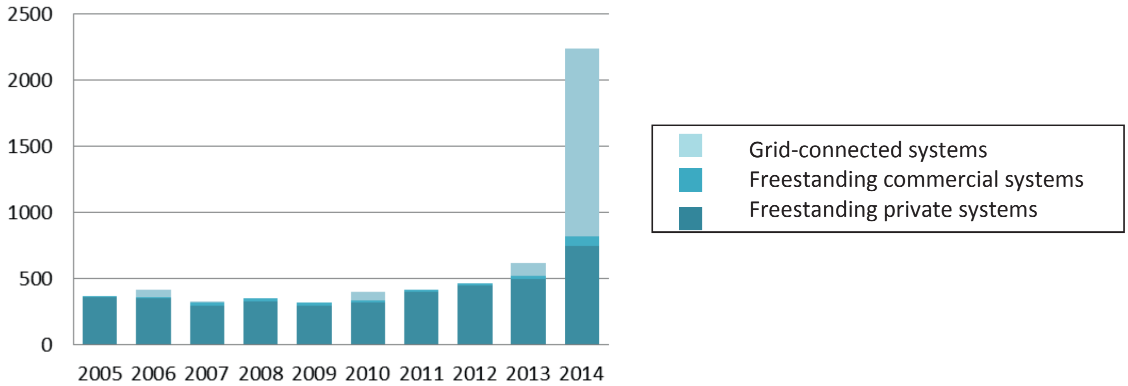


Figure 6-1 Annually installed new capacity of photovoltaics in Norway in kWp [26]

6.3 Geothermal energy

Ground source heat pumps are the only utilization of geothermal energy in Norway per 2011 [26]. It is mostly closed systems with energy wells in rock that are used.

In 2011 The Norwegian Water Resources and Energy Directorate (NVE) published a report which stated that ground source heat pumps theoretically can cover the total demand for heating and cooling in Norway. According to NVE, geothermal energy can represent a significant contribution to the Norwegian energy supply. Geothermal energy can replace most of the oil and electricity used for heating and cooling today. NGU estimates the technical potential for energy savings through the use of geothermal energy and heat pumps in Norway to be about 37 TWh.

Use of geothermal energy to generate electricity is not applicable in Norway at present or in the near future.

6.4 Hydropower

In 2014 there were about 1,500 small and large hydropower plants in Norway, which together are generating about 130 TWh annually on average. The installed capacities in the power plants are ranging from just a few hundred kW to more than 1,200 MW. Total hydropower production capacity in Norway was 30,960 MW as of January 2014 [26].

The total technical/economic hydropower potential in Norway was in the beginning of 2014 estimated at 214 TWh/year. 51 TWh of this total potential is in protected areas and is not available for development. This means that it remains a real potential of 32 TWh/year for new hydropower generation. This is illustrated in Figure 6-2 [28].

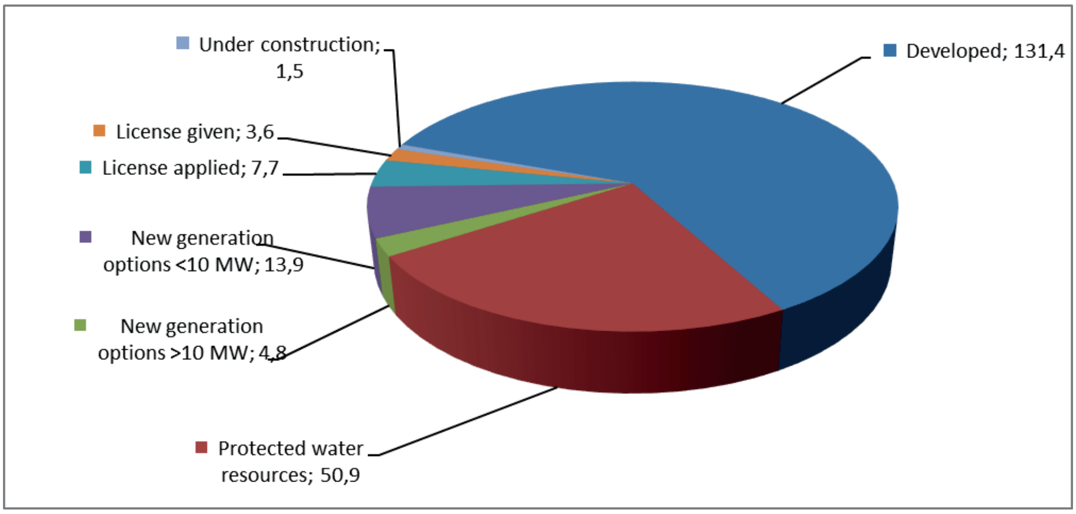


Figure 6-2 Total hydropower potential in Norway as of 01.01.2014 (mean annual production in TWh)

In 2013 the hydropower production in Norway was 129.0 TWh. This is 96.1% of the total electric power production in Norway the same year. The gross consumption of electric energy in Norway 2013 was 129.2 TWh (including electric boilers and losses). This means that nearly 100% of the gross consumption of electric energy in Norway is covered by hydropower production.

According to Figure 6-2, the potential for new small scale generation (<10 MW) is 13.9 TWh/year. This generation will most likely be unregulated and connected to the MV and LV distribution grids. Since 2013, several small scale hydro power plants have been put into operation while others are under construction or being planned. Connecting of small scale hydro power plant to the distribution grids have been a big issue in Norway for the last five to ten years. Most of the hydro power plants are located in sparsely populated areas with weak distribution grids with limited transmission capacity. Because of this, grid connection of small scale hydro power plants often triggers major investments in the distribution grids in order to maintain a satisfactory quality of supply to customers connected to the same grid.

6.5 Wind energy

Wind turbines produced 1,6 TWh or 1.1 % of the Norwegian electricity generation in 2012 [29]. The potential for wind power generation in Norway is estimated to 250 TWh/year [30], but only a small part of this is possible to realize in near future. Almost 70% of the estimated resources are located in Finnmark, the northernmost county in Norway. Low consumption of electric energy within the county combined with very long distances to consumption centers further south makes it unlikely to ever utilize more than just a fraction of the estimated wind potential.

Wind energy is, like direct solar energy, a relatively **unpredictable source** and the output will vary considerably from hour to hour, day to day and season to season.

Wind energy in Norway is mainly utilized in large wind parks located along the coast and is connected to the transmission or regional transmission grid. Only a few single windmills or smaller wind parks are connected to the distribution grid. This trend will most likely not change in near future.

6.6 Ocean energy

Wave energy

Utilization of wave energy is still at an early stage. Wave energy can be competitive without government support in certain niches, such as operation of navigational beacons, fish breeding, seawater desalination and power supplies to isolated coastal communities where only expensive electricity from diesel generators are available.

Tidal water energy

Tidal water is still a little used energy source in Norway, but some test constructions are established using tidal turbines.

Wave and tidal water electricity generation will not be appropriate technologies to consider during the planning of distribution networks – not today and not in the near future.

7 Smart Grids – a tool for cost efficient RES and active customer integration

The term Smart grids was introduced in the late 90's, but today's meaning of the term was perhaps initiated by the article "Toward a Smart Grid" [31] from 2005. It focused in finding new ways to make the power system more robust. The idea was triggered among others by the extensive interruptions of the power system in North America in august 2003. The vision was a more adaptive and automatic response to the interruptions and abnormal situations in the power system.

Climate change and greenhouse gas emissions gained increased focus at the same time, and it became more desirable to introduce new technologies in order to reduce the greenhouse gas emissions. Many countries started to focus on replacing fossil energy sources with renewables. This dimension has gained just as much focus in today's Smart grid concept. The term Smart grids includes today most of the issues involved in planning, operation and maintenance of the electrical power system, including issues concerning the interaction with the distribution grid customers (generation, consumption, SmartHouse).

Smart grid characteristics:

- Active and energy efficient end users/customers
- Electrification of transport
- Distributed and renewable energy generation
- Active distribution and transmission networks

Key technologies for realization of the Smart grid concept will be:

- AMS – Advanced Metering Systems - smart metering
- ICT – Information and communication technologies
- New sensor and control technologies
- Observable and controllable devices, components and equipment, e.g.:
    - On/off/control of loads
    - On/off/control of local distributed generation
    - On/off/control of electric vehicle charging
    - Control of converters/FACTS[5]/energy storage facilities etc.

The European Commission's Smart Grids Task Force have defined 6 high level services for the future Smart Grids [32]:

- Enabling the network to integrate users with new requirements
- Enhancing efficiency in day-to-day grid operation
- Ensuring network security, system control and quality of supply
- Enabling better planning of future network investment
- Improving market functioning and customer service
- Enabling and encouraging stronger and more direct involvement of consumers in their energy usage and management

Implementation of Smart Grids will be different in different regions and countries on the basis of the characteristics of the different electrical energy systems and the forces that drive developments. Focus will be different in North America, Europe, Asia, etc. although there will be many similarities. Since the development of Smart grids in different regions takes place at the same time, there are also many different definitions of the term Smart grids.

The International Electrotechnical Commission (IEC), the leading global organization that prepares and publishes International Standards for all electrical and related technologies, has adopted the following definition of Smart grids (www.electropedia.org):

[5] FACTS – Flexible alternating current (AC) transmission system

Electric power system that utilizes information exchange and control technologies, distributed computing and associated sensors and actuators, for purposes such as:

- *to integrate the behavior and actions of the network users and other stakeholders,*
- *to efficiently deliver sustainable, economic and secure electricity supplies*

The European Commission gives up to today one of the most important European reference for the term Smart grid in Mandate 490 "Standardization Mandate to European Standardization Organizations (ESOs) to support European Smart Grid deployment" (March 2011) [32]. In this mandate, the European Commission asks the European Standardization Organizations (CEN/CENELEC/ETSI) to develop a consistent set of standards for Smart grids. In the mandate, the following definition of Smart grid is used:

A Smart Grid is an electricity network that can cost efficiently integrate the behavior and actions of all users connected to it – generators, consumers and those that do both – in order to ensure economically efficient, sustainable power system with low losses and high levels of quality and security of supply and safety.

This definition does not say anything about what is new with Smart grids. The distribution grid has always integrated the behavior and actions of all users connected to it, and the purpose has always been to ensure economic efficiency, low losses and high level of quality and security of supply and safety. The only element in this definition that implies something partly new is the word *sustainable.*

IEC describes in [33] the concept of Smart grids like this:
"Smart Grid" is today used as marketing term, rather than a technical definition. For this reason there is no well-defined and commonly accepted scope of what "smart" is and what it is not. However smart technologies improve the observability and/or the controllability of the power system. Thereby Smart Grid technologies help to convert the power grid from a static infrastructure to be operated as designed, to a flexible, "living" infrastructure operated proactively. SG3 defines Smart Grids as the concept of modernizing the electric grid. The Smart Grid is integrating the electrical and information technologies in between any point of generation and any point of consumption.

This description is consistent with the definition given by **SINTEF Energy** in [2]:
Smart grids can be defined as a label on the future power system (2020/2050), where advanced metering and control systems (AMS, smart meters) and communication to "all" grid customers and facilities plays a central role. Smart grids are needed to realize objectives and demands made on the future energy system, which among other things is characterized by increased use of renewable and intermittent energy sources and increased degree of electrification (transport, heat pumps, industrial processes, etc.).

As the result of the mandated work requested through the M/490 mandate [32], working groups of the CEN-CENELEC-ETSI Smart Grid Coordination Group have compiled and published several reports regarding standards, methods, models, tools, interoperability and information security for Smart Grids. *APPENDIX C – Smart grid architecture* presents a brief overview of the European Conceptual Model, interoperability and interoperability in the Smart Grid (the SGAM model).

8 Elements in the future distribution grid that will affect the power system planning and operation

Expected changes in the future distribution grid will affect the power system planning and operation in different ways. In this chapter, possible changes are listed and discussed with emphasis on their consequences for distribution system operation and planning. The list is by no means exhaustive.

The elements are divided in five groups:
1. New components in the distribution grid
2. More accessible data due to more metering and new data sources (e.g. sensors and control equipment)
3. Smart solutions related to operation, monitoring and protection
4. Distributed generation (DG)
5. Demand Side Management (DSM)

For each element some characteristics are listed together with positive and negative consequences for both network operation and planning.

8.1 New components in the distribution grid

Some new elements/components introduced with Smart Grid are listed in Table 8-1 to Table 8-5. These components do not necessarily represent new technologies, but have not been commonly used in MV or LV distribution networks before.

These new elements/components are discussed under this heading:
- SVC/STATCOM-D
- Storage
- Electric Vehicles (EVs)
- Energy efficient but high powered appliances
- Voltage booster

8.1.1 SVC/STATCOM –D

A static VAR compensator (SVC) is a set of electrical devices for providing fast-acting reactive power on electricity transmission networks. SVCs are part of the Flexible AC transmission system device family, regulating voltage, power factor, harmonics and stabilizing the system. Typically, an SVC comprises one or more banks of fixed or switched shunt capacitors or reactors, of which at least one bank is switched by thyristors (Ref.: Wikipedia).

A static synchronous compensator (STATCOM), also known as a static synchronous condenser (STATCON), is a regulating device used on AC electricity transmission networks. It is based on power electronics voltage source converter and can act as either a source or sink of reactive AC power to an electricity network.
A static VAR compensator can also be used for voltage stability. However, a STATCOM has better characteristics than an SVC. When the system voltage drops sufficiently to force the STATCOM output current to its ceiling, its maximum reactive output current will not be affected by the voltage magnitude. Therefore, it exhibits constant current characteristics when the voltage is under the limit. In contrast, the SVC's reactive output is proportional to the square of the voltage magnitude. This makes the provided reactive power decrease rapidly when voltage decreases, thus reducing its stability. In addition, the speed of response of a STATCOM is faster than that of an SVC and the harmonic emission is lower, however STATCOMs typically exhibit higher losses and may be more expensive than SVCs, so the (older) SVC technology is still widespread.

To compensate for the voltage fluctuations caused by DGs in a distribution grid, solutions with SVCs and STATCOM are made available also for the distribution grids.

Table 8-1 SVC/STATCOM-D

Characteristics	Operational consequences	Planning consequences
• Active voltage regulation using power electronics, capacitors and coils. • Improves the power factor (cos(φ))	Positive: • Improves voltage quality • Improves quality of supply • Increases the transfer capability of the grid	Positive: • Active control of reactive power (cos(φ)) • Improves voltage quality • Improves quality of supply • Increases the transfer capability of the grid • Reducing the need for grid reinforcements • Available technology
	Negative: • Advanced technology - Competence - Maintenance - Lifespan	Negative: • Increased costs for O&M • Very expensive technology • May result in more faults and interruptions

8.1.2 Storage

The introduction and integration of variable renewable and distributed generation into the distribution grid has increased rapidly over the last decade, and the pace is likely to accelerate even more into the future. This will require a higher ability to keep the balance of generation and demand in the grid, even if dispatchable resources are diminishing. Storage can greatly increase the reliability of the grid and will help the distribution grid become more efficient and increase the possible amount of renewable energy generation which can be integrated.

Battery Energy Storage Systems (BESS) and capacitors/supercapacitors (SC) are two storage technologies appropriate for use in distribution system.

BESS comprises mainly of batteries, control and power conditioning system. The batteries are made of stacked cells where-in chemical energy is converted to electrical energy and vice versa. The desired battery voltage as well as current levels are obtained by electrically connecting the cells in series and parallel. The batteries are rated in terms of their energy and power capacities. Some important features of a battery are efficiency, life span (stated in terms of number of cycles), operating temperature, depth of discharge[6], self-discharge[7] and energy density [34].

Supercapacitor (**SC**) is a high-capacity electrochemical capacitor with capacitance values much higher than other capacitors (but lower voltage limits) that bridge the gap between electrolytic capacitors and rechargeable batteries. They typically store 10 to 100 times more energy per unit volume or mass than electrolytic capacitors, can accept and deliver charge much faster than batteries, and tolerate many more charge and discharge cycles than rechargeable batteries. Supercapacitors are used in applications requiring many rapid charge/discharge

[6] Batteries are generally not discharged completely and depth of discharge refers to the extent to which they are discharged
[7] Some batteries cannot retain their electrical capacity when stored in a shelf and self-discharge represents the rate of discharge

cycles rather than long term compact energy storage: within cars, buses, trains, cranes and elevators, where they are used for regenerative braking, short-term energy storage or burst-mode power delivery. (Source: https://en.wikipedia.org/wiki/Supercapacitor).

Table 8-2 Storage

Characteristics	Operational consequences	Planning consequences
• Smooth out power variations caused by e.g. renewable energy production • Improves voltage quality (reduces voltage variations) • Can maintain power supply (limited) during fault and interruptions •	Positive: • Frequency regulation • Reduces voltage variations • Load leveling / peak shifting • Possible to maintain power supply for a limited period after an interruption (Micro grid, UPS, …) • Reduces power variations from unregulated renewable generation (smooth out the network load) • Island mode operation with RES • Black start capability during grid outages	Positive: • Reducing the need for grid reinforcements • Improves the reliability and voltage quality • Reduces interruption costs • Available today, but somewhat immature yet
	Negative: • Increased maintenance • Increased costs for O&M • Requires new competence • Requires additional investments to exploit all possible benefits (Micro grid, UPS,…)	Negative: • Increased costs for O&M • Expensive technology

8.1.3 Electric Vehicles (EVs)

The number of Electric Vehicles (EVs) and Plug in Hybrid Electric vehicles (PHEVs) in Norway is increasing rapidly. The development of new EV models and better batteries happens fast. The trend is larger batteries and installation of home charging stations with 3-10 kW capacity. New fast charging stations with several charging points with capacity of 50 -100 kW each are frequently established. Electrical trucks and busses will also be more common within the few next years. This development could trigger the need of significant reinforcements in the distribution grid.

Table 8-3 Electric Vehicles (EVs)

Characteristics	Operational consequences	Planning consequences
• Charging at home • Fast charge • Vehicle to grid (V2G) • Vehicle to home (V2H) • Battery capacity is increasing • Kia Soul EV: - 27 kWh battery capacity. - Fast charge, (20 -50 kW DC, CHAdeMO) - Semi fast charge & Home charging station (3,7-7 kW AC, Type 2) - Slow charge at home (2 kW AC, Schuko) • Tesla Modell S: 60-85 kWh battery capacity. - Tesla super charge (120 kW DC, Tesla Model S) - Quick charge (50 kW) - Semi fast charge & Home charging station (3,7-43 kW, AC, Type 2, Ind.3-pin or Ind.5-pin) - Slow charge at home (2-3 kW AC, Schuko)	Positive: • V2H – EV can be used as battery storage at home, but extended use of battery will reduce the battery lifetime. • V2G - EV can be used as battery storage in the grid. This will also affect the battery lifetime. • Quick charge in selected places – strong grid close to major arterial roads/ malls and etc.	Positive: • Transition from 230V IT to 400V TN networks will be necessary (in Norway) • Grid dimensioning • Introduce new components (battery, DSTATCOM) • V2H – reduces ENS/CENS - Time limited
	Negative: • Large load (power) in charging mode • Coinciding need of charging of many EVs at the same time (e.g. after work)	Negative: • Power demand of households increases • Increased variations in power demand • Voltage problems • The need for grid reinforcements in LV and MV • Management and control of voltage and load • V2G and V2H are immature technologies • Number of EVs increases – load problem increases

8.1.4 Energy efficient but high powered appliances

Climate change and rising energy costs in much of the world has resulted in increased demand for more energy efficient electrical appliances. The appliances shall also be compact and efficient to use. This leads to among other things, the development of energy efficient but high-powered appliances like induction cookers, tankless or demand-type water heaters, heat pumps. Such appliances draws either large currents over short periods or nonlinear currents. This has undesirable effects on power quality in low-voltage networks, e.g. increased level of flicker, voltage changes and harmonics [35].

Table 8-4 Energy efficient but high powered appliances

<table>
<tr><th>Characteristics</th><th>Operational consequences</th><th>Planning consequences</th></tr>
<tr><td rowspan="2">Energy efficient (Energy losses are small)
High powered (e.g. heating water with 15 kW instead of 2 kW)</td><td>Positive:</td><td>Positive:
Transition from 230V IT to 400V TN networks will be necessary (in Norway)
Grid dimensioning
Introduce new components (battery, DSTATCOM, ..)</td></tr>
<tr><td>Negative:
Weak grid in Norway (230 V IT) might give voltage quality problems (variations, dips, …)
Large and rapid load variations</td><td>Negative:
Power demand of households increases
Increased variations in power demand
Voltage problems
The need for grid investments:
- Reinforcements in LV and/or MV grid
- Or new equipment/ tools for management and control of voltage and load.</td></tr>
</table>

8.1.5 Voltage booster

A voltage stabilizing booster is installed by electric utilities in the low voltage grid to ensure a continuous and stepless voltage correction to the end user. It is typically used where a long distribution line causes voltage drops according to power use. Voltage boosters are available for different voltage systems and power levels.

Areas of application [8]:

- Stabilizing voltage for long LV lines or sea cables.
- Supporting telecom base station transmitters, vacation homes, weekend cottages, rural homes and stores, farms, fish farms, production plants etc.
- Provisional power supply for constructional areas, tunnels, etc.
- Stabilizing voltage in the grid when voltage fluctuations is caused by distributed generation like solar cells, hydropower or wind power plants.
- Stabilizing and lifting voltage on the LV side, when voltage drop is caused on 1 kV or higher.

Table 8-5 Voltage booster

Characteristics	Operational consequences	Planning consequences
• Increases or decreases the voltage at the connection point in the grid	Positive: • Can postpone investments in the grid • Can be used on long lines for improving the voltage conditions	Positive: • An alternative to grid reinforcement • Can postpone grid reinforcement • Available technology • Relatively cheap
	Negative: • Increased operation and maintenance costs, mostly because of large losses. • Possible source of error	Negative: • Increased operation and maintenance costs, mostly because of large losses. • Regulates the voltage slowly – not fast enough to handle rapid voltage variations

[8] Source: www.Magtech.no

8.2 More accessible data

The implementation of smart meters and smart grids with extended use of new sensors provides the DSOs with a lot more data than before.

These alternatives are discussed under this heading:

- Smart metering (AMI) at consumers
- Smart metering in distribution substations
- New sensors

8.2.1 Smart metering – consumers

A smart meter is an electronic device that records consumption in electric energy in intervals of an hour or less and communicates that information at least daily back to the utility for monitoring and billing. Smart meters enable two-way communication between the meter and the central system. Unlike home energy monitors, smart meters can gather data for remote reporting. Such an advanced metering infrastructure (AMI) differs from traditional automatic meter reading (AMR) in that it enables two-way communications with the meter. "Smart Meters" can also monitor and report power quality information and power outage notifications. Every electricity meter installed at customers in Norway shall be a smart meter by 2019. Advanced metering and control systems (AMS in Norwegian) have three main functions: Metering, communication and network control.

Table 8-6 Smart metering (AMI) - consumers

Characteristics	Operational consequences	Planning consequences
• Value registration at least every 15 minutes • Power metering in 4 quadrants (consumption and generation, active and reactive) • Register the power quality (voltages, inter-ruptions, earth faults, …) • Internal switch for disconnecting/connecting load • Enables communication between the meter, customer, local in-house energy management system and the DSO.	Positive: • Real time info about the load • Automatic notification of network faults and abnormal events in the grid (earth fault, interruptions, abnormal voltages, … • Automatic collecting measurement values • Provides opportunities for smart ways to operate the distribution grid based on real time information about the load • Balance measurement Negative: • Communication errors will cause problems	Positive: • Improved basis for load determination, forecasting and load flow calculations • Improved basis regarding power losses, power quality, ENS/CENS • Improved grid state documentation • Available technology but somewhat immature yet • Basis for flexible tariffs (network and power) – Demand Response (DR) Negative: • Generates large amounts of data. Need effective methods to handle these big data. • Restrictions in data storage over time in Norway – for protecting the customers. Aggregate and store information at higher level than customers is possible.

8.2.2 Smart metering – distribution substations

Smart meters installed in distribution substations provide much the same opportunities as smart meters installed at customers. The internal switch in the smart meter may not be able to disconnect load in the same way, but remote control of separate disconnectors in the substation is possible through the communication solution.

Table 8-7 Smart metering (AMI) – distribution transformers

Characteristics	Operational consequences	Planning consequences
• Value registration at least every 15 minutes • Aggregated power metering in 4 quadrants (consumption and generation, active and reactive) • Register the power quality (voltages, inter-ruptions, earth faults, …) • Makes balance measurement possible • When communication solution is established to the distribution substation, other opportunities for smart grid solutions opens up.	Positive: • Real time info about the aggregated load • Automatic notification of network faults and abnormal events in the grid (earth fault, interruptions, abnormal voltages, … • Automatic collecting measurement values • Provides opportunities for smart ways to operate the distribution grid based on real time information about the load • Balance measurement may reveal: - Errors in documentation - Earth faults - Transformer load - Power theft - Voltage drop in LV network	Positive: • Improved basis for load determination, forecasting and load flow calculations • Improved basis regarding power losses, power quality, ENS/CENS • Improved grid documentation • Opportunities for using smart grid solutions as an alternative to grid reinforcement • Available technology but somewhat immature yet
	Negative: •	Negative: • Generates large amounts of data. Need effective methods to handle these big data.

8.2.3 New sensors

New sensors installed in LV and MV distribution grids, communicating with local (e.g. in distribution substations) and/or central control systems (e.g. the DSOs main control center), provide minute-by-minute information about network conditions that can be used for many purposes within smart grids. The use of new sensors in the distribution systems will escalate in the coming years as the grids become smarter. Internet of things and automation are two relevant keywords for this topic.

Table 8-8 New sensors

Characteristics	Operational consequences	Planning consequences

• Provides minute-by-minute or even faster network information like e.g.:
- Open door
- Temperatures (air, oil, conductor, …)
- Decay
- Mechanical load
- Electrical fault
  - Insulation strength
  - …..
	Positive:
	• Faster fault location
	• Improved condition monitoring
	• Detect and correct errors before interruptions occurs
	• Reduce CENS (Cost of Energy Not Supplied)
	• Improved power quality
	• Monitor the degradation of grid components
	• Better utilization of the grid
		Positive:
		• Better knowledge of the state of the grid:
		  - Better dimensioning (less faults in the future?)
		  - Proper maintenance (reduced costs)
		• Affects ENS and CENS
		  - Faster fault location and isolation
		  - Detect errors before interruption occurs
		  - Reduce the number of interruptions
		  - Reduce interruption durations
		  - Reduce interruption costs (CENS)
		• Available technology
		• Better utilization of the grid

	Negative:
	• Sensors fail too and can cause more interruptions and repairs.
		Negative:
		• Necessary to consider the advantage of measuring up against possible consequences of faulty sensor
		• Can affect ENS and CENS in a negative way when sensors fail by increasing:
		  - number of interruptions
		  - interruption durations
		  - interruption costs (CENS)

8.3 Smart solutions related to operation, monitoring and protection

These alternatives are discussed under this heading:

- Phasor Measurement Unit (PMU)
- Real Time Thermal Rating (RTTR)
- Smart distribution substations
- Distribution Management System (DSM)
- Micrograds

8.3.1 Phasor Measurement Unit (PMU)

A phasor measurement unit (PMU) is a device that measures the electrical waves on an electricity grid using a common time source to synchronization. Time synchronization allows real-time measurements of multiple remote measurement points on the grid. The resulting measurement is known as a synchrophasor. PMUs are considered one of the most important measuring devices in the future of power systems. A PMU can be a dedicated device, or the PMU-function can be incorporated into a protective relay or other device [9]. Without ubiquitous, accurate and reliable real-time sensors, the power system will not have the resiliency, reliability and capacity to manage the unprecedented number of variable renewable energy sources and millions of intelligent devices and systems. PMUs have primarily been used in transmission and HV distribution grids, but are now considered useful in MV distribution grids as well. NTE Nett has recently tested the use of a PMU in one of their MV distribution grids.

Table 8-9 Phasor Measurement Unit (PMU)

Characteristics	Operational consequences	Planning consequences
• Current, voltage and frequency measurements are taken by PMUs at selected locations (critical nodes) in the power system and stored in a data concentrator every 100 milliseconds. The measured quantities include both magnitudes and phase angels, and are time-synchronized via GPS receivers with accuracy of < 1 microsecond. • Provides synchronized snapshots of the status of the monitored nodes. By comparing the snapshots with each other, both steady- and dynamic state of critical nodes in the grid can be observed.	Positive: • Dynamic monitoring of critical nodes in the power system. • Early warning system that contributes to increase system reliability • Detects rapidly stability problems in power systems. • Enables increased load of the grid – towards the dynamic limit	Positive: • Improved utilization of the grid capacity. • Improve grid reliability •
	Negative: •	Negative: • Expensive

[9] Source: https://en.wikipedia.org

8.3.2 Real Time Thermal Rating (RTTR)

Real Time Thermal Ratings System is originally developed for the transmission lines using actual meteorological data and real-time conductor temperatures and line loadings. This system provide, on probability basis, much higher ampere capacity ratings than those derived from conventional methods. With the increased amount of DG connected to the distribution networks, RTTR has become a relevant solution for these networks as well.

Sensors connected to the conductors send information about conductor temperatures to the central control center (DMS - distribution management system), which controls the thermal rating of the lines. Overhead lines are traditionally given a conservative ampere capacity rating according to recommendations given in IEC 1597 (1995).[10]

Table 8-10 Real Time Thermal Rating (RTTR)

Characteristics	Operational consequences	Planning consequences
• Thermal rating for a line or a cable is decided from measured temperatures in air and on conductor, wind speed, solar radiation and more. • RTTR are based on the observation of the conductor temperature. • Higher transmission capacity in winter than in summer	Positive: • Increases the transmission capacity for most of the time compared to today's conservative thermal ratings decided by 20°C in air, solar radiation of 900 W/m^2 and wind speed of 1 m/s.	Positive: • Thermal ratings for lines and cables become dynamic. The transmission capacity becomes higher in the winter than in the summer. • Better utilization of the real time transmission capacity • Reduces the need for grid reinforcements / grid investments • Available technology
	Negative: • Need equipment for regulating load and generation to avoid overloading lines and cables. • Hidden faults and weaknesses in the grid appears due to higher loads and higher temperatures on the conductors. • The number of faults and interruptions may increase and lead to increased ENS and CENS.	Negative: • Need equipment for regulating load and generation to avoid overloading lines and cables. • Hidden faults and weaknesses in the grid appears due to higher loads and higher temperatures on the conductors. • The number of faults and interruptions may increase and lead to increased ENS and CENS. • The network analyzing tool must be able to handle real time thermal ratings.

[10] Maximum temperature on conductor 80 °C , Air temperature 20 °C, wind speed 1 m/s, Solar radiation 900 W/m^2

8.3.3 Smart distribution substations

A distribution substation (MV/LV) has traditionally not provided the utility with any information regarding conditions in the grid or in the substation itself. Substation automation has traditionally been focused on functions like monitoring, controlling and collecting of data inside the substation. With Smart Grids comes a new level of expectation for distribution automation. Substation automation is expected to expand dramatically with increased control of relays, capacitor banks and voltage regulators along the feeders. New applications are expected to incorporate DER, AMI and DR-functions.

Table 8-11 Smart distribution substations

Characteristics	Operational consequences	Planning consequences

• Real time coordination of distributed generation and transformer tap-changer.
• Tap changer control based on real time information
• Fault location, notification and isolation of
  - Earth fault
  - Short circuit
  - Phase interruption
  - Overload
• Self-healing grid
• Automatic switchover in the grid for optimal operation and minimum loss
	Positive:
	• Better control of network conditions (load, voltage, faults, …)
	• Improved power quality – quicker fault location and switchovers.
		Positive:
		• Improved basis for planning
		• Knowledge about network conditions (load, voltage, power quality, …)
		• Relatively inexpensive to establish if infrastructure and key systems already are in place

	Negative: • Complex system. Big challenge to maintain an overview of the whole system during operation.	Negative: • How will smart grid technologies affect the reliability of the grid? New components can also fail and might have shorter lifetime than traditional grid components….. • Available technology but somewhat immature yet • A lot will happen during a few years

8.3.4 Distribution Management System (DMS)

A Distribution Management System (DMS) is a collection of applications designed to monitor and control the entire distribution network efficiently and reliably. It acts as a decision support system to assist the control room and field operating personnel with the monitoring and control of the electric distribution system. Improving the reliability and quality of service in terms of reducing outages, minimizing outage time, maintaining acceptable frequency and voltage levels are the key deliverables of a DMS.

DMS access real-time data and provide all information on a single console at the control center in an integrated manner. The typical data flow in a DMS has the SCADA[11] system, the Information Storage & Retrieval (ISR) system, Communication (COM) Servers, Front-End Processors (FEPs) & Field Remote Terminal Units (FRTUs).[12]

Table 8-12 Distribution Management System (DMS)

Characteristics	Operational consequences	Planning consequences
• Improved monitoring, control and management of operating conditions in the grid • Possible to implement automatics and control over the grid from the control center • Improved generation of reports and statistics	Positive: • Control centers will be necessary in order to have control and be able to operate the grid efficient in the future. • Be able to handle dynamic operating conditions • Simplifies and improves some operational functions (statistics and reports, etc.) • Faster fault location	Positive: • Collection of large amounts of monitoring data provides better insight. This in turn provides a better basis for power system analysis and planning. • Smart solutions may reduce time to fault location, number of outages and ENS/CENS. • Available technology
	Negative: •	Negative: • Comprehensive and expensive

[11] SCADA – Supervisory control and data acquisition – is a control system architecture for high-level process supervisory management.

[12] Source. https://en.wikipedia.org

8.3.5 Microgrids

Microgrids are electricity distribution systems containing loads and distributed energy resources, (such as distributed generators, storage devices, or controllable loads) that can be operated in a controlled, coordinated way either while connected to the main power network or while islanded (*CIGRÉ C6.22 Definition, ref. [36])*.

<u>CIGRÉ C6.22 Definition Qualifiers:</u>
Generators cover all sources possible at the scales and within the context of a microgrid, e.g. fossil or biomass-fired small-scale combined heat and power (CHP), photovoltaic modules (PV), small wind turbines, mini-hydro, etc.

Storage Devices include all of electrical, pressure, gravitational, flywheel, and heat storage technologies. While the microgrid concept focuses on a power system, heat storage can be relevant to its operation whenever its existence affects operation of the microgrid. For example, the availability of heat storage will alter the desirable operating schedule of a CHP system as the electrical and heat loads are decoupled. Similarly, the pre-cooling or heating of buildings will alter the load shape of heating ventilation and air conditioning (HVAC) system, and therefore the requirement faced by electricity supply resources.

Controlled loads, such as automatically dimmable lighting or delayed pumping, are particularly important to micrograms simply by virtue of their scale. Inevitably in small power systems, load variability will be more extreme than in utility-scale systems. The corollary is that load control can make a particularly valuable contribution to a microgrid.

Table 8-13 Micrologrids

<table>
<tr><th>Characteristics</th><th>Operational consequences</th><th>Planning consequences</th></tr>
<tr><td rowspan="2">• Limited electrical systems that can be operated in a controlled way either while connected to the main power grid or while islanded e.g. during network outages or in isolated places with no nearby power grids.
• The extent depends on the available generation capacity and the load in the area. It can be a house, a residential estate, a farm, a village or a municipality.
• The generation and/or the load must be controllable in order to maintain equilibrium.
• AC or DC microgrids</td><td>Positive:
• The grid companies (distribution system operators) need to monitor and control micro grids for security.
• Excellent opportunity for improving power quality (reliability).</td><td>Positive:
• Improves reliability. Great potential for maintaining a reliable power supply
• Smart homes may be micro grids with EV, PV, windmill, fuel cell, etc.</td></tr>
<tr><td>Negative:
• Challenging maintaining an overview and having control
• Personal safety for people who work in the grid</td><td>Negative:
• Increased demands for control and safety
• Available technology but somewhat immature yet
• May be expensive in relation to the benefits
• Challenging maintaining an overview of all micro grids and their opportunities
• Tools for power system analyses must be able to calculate on micro grids.</td></tr>
</table>

8.4 Distributed generation (DG)

Distributed generation, is defined as generation of electric energy by multiple sources which are connected to the power distribution system (http://www.electropedia.org).

Distributed generation, also called embedded generation, dispersed generation, distributed energy, on-site generation (OSG) or district/decentralized energy is generated or stored by a variety of small, grid-connected devices referred to as distributed energy resources (DER) or distributed energy resource systems.

Conventional power stations, such as coal-fired, gas and nuclear powered plants, as well as hydroelectric dams and large-scale solar power stations, are centralized and often require electricity to be transmitted over long distances. By contrast, DER systems are decentralized, modular and more flexible technologies, that are located close to the load they serve, albeit having capacities of only 10 megawatts (MW) or less. These systems can comprise multiple generation and storage components. In this instance they are referred to as Hybrid power systems.

DER systems typically use renewable energy sources, including small hydro, biomass, biogas, solar power, wind power, and geothermal power, and increasingly play an important role for the electric power distribution system. A grid-connected device for electricity storage can also be classified as a DER system, and is often called a distributed energy storage system (DESS). By means of an interface, DER systems can be managed and coordinated within a smart grid. Distributed generation and storage enables collection of energy from many sources and may lower environmental impacts and improve security of supply.
(https://en.wikipedia.org/wiki/Distributed_generation).

More information about RES can be found in *APPENDIX B – Renewable energy sources (RES).*

These DG alternatives are discussed under this heading:

- Distributed Generation in general (DG)
- Photovoltaics (PV)
- Distributed Wind Power
- Combined Heat and Power
- Hydro Power

8.4.1 Distributed Generation in general

Generation from renewable energy sources (RES) have some common characteristics and consequences. Some of these are mentioned in Table 8-14.

Table 8-14 Distributed Generation in general (DG)

Characteristics	Operational consequences	Planning consequences
• Renewable energy sources (RES) • No reservoir • Not adjustable • Generates when there is sufficient water in the stream, the sun is shining, wind is blowing, etc.	Positive: • DG with additional systems for e.g. voltage regulation, active management & control of the grid and storage, might improve the power quality and enable microgrids.	Positive: • DG with additional systems for e.g. voltage regulation, active management & control of the grid and storage, might improve the power quality, enable microgrids, reduce network losses and increase network utilization.
	Negative: • Not adjustable generation • Complex load situation – forecasting and prediction are difficult • Voltage variations due to variation in generation • Reverse power flow • Protection challenges	Negative: • Not adjustable generation • Complex load situation – forecasting and prediction are difficult • Voltage rise • Reverse power flow • Protection challenges

8.4.2 Photovoltaics (PV)

Photovoltaics (PV) cover the conversion of light into electricity using semiconducting materials that exhibit the photovoltaic effect. A typical photovoltaic system employs solar panels, each comprising a number of solar cells, which generate electrical power.

The power output from a solar cell is dependent on direct sunlight, so about 10-25% is lost if a tracking system is not used, since the cell will not be directly facing the sun at every hour of the day.[13] Power output is also adversely affected by weather conditions such as the amount of dust and water vapor in the air or the amount of cloud cover.

Advances in technology and increased manufacturing scale have reduced the cost, increased the reliability, and increased the efficiency of photovoltaic installations and the levelized cost of electricity from PV is competitive, on a kilowatt-hour basis, with conventional electricity sources in an expanding list of geographic regions [37].

Net metering and financial incentives, such as preferential feed-in tariffs for solar-generated electricity, have supported solar PV installations in many countries. More than 100 countries now use solar PV. After hydro and wind power, PV is the third renewable energy source in terms of globally capacity. In 2014, worldwide installed PV capacity increased to 177 gigawatts (GW), which is two percent of global electricity demand. China, followed by Japan and the United States, is the fastest growing market, while Germany remains the world's largest

[13] http://www.solarpowerworldonline.com/2016/05/advantages-disadvantages-solar-tracker-system/

producer (both in per capita and absolute terms), with solar PV providing seven percent of annual domestic electricity consumption. (https://en.wikipedia.org/wiki/Photovoltaics).

Table 8-15 Photovoltaics (PV)

Characteristics	Operational consequences	Planning consequences
• Smaller solar power plants on rooftops or areas close to buildings (residential buildings, office buildings, industrial buildings, etc.). - Produce mainly for local use - Surplus is either sold or stored in batteries • Larger PV power plants - Produce mainly for distant use - Connected to MV or HV distribution grid	Positive: • Same as Table 8-14	Positive: • Same as Table 8-14
	Negative: • Same as Table 8-14	Negative: • Same as Table 8-14

8.4.3 Distributed Wind Power

Wind power is the use of airflow through wind turbines to mechanically power generators for electric power. Wind power, as an alternative to burning fossil fuels, is plentiful, renewable, widely distributed, clean, produces no greenhouse gas emissions during operation, consumes no water and uses little land.

Small onshore wind farms or single wind turbines can feed energy into the distribution grid or provide electric power to isolated off-grid locations. Wind power gives variable power which is very consistent from year to year but which has significant variation over shorter time scales.

Table 8-16 Distributed Wind Power

Characteristics	Operational consequences	Planning consequences
• Small / single wind turbines in connection to industry, farms, residential homes, housing estates, etc. • Produce mainly for local/own use • Surplus is either sold or stored in batteries	Positive: • Same as Table 8-14	Positive: • Same as Table 8-14
	Negative: • Same as Table 8-14	Negative: • Same as Table 8-14

8.4.4 Combined Heat and Power (CHP)

Cogeneration or combined heat and power (CHP) is the use of a heat engine or power station to generate electricity and useful heat at the same time. Trigeneration or combined cooling, heat and power (CCHP) refers to the simultaneous generation of electricity and useful heating and cooling from the combustion of a fuel or a solar heat collector.

Cogeneration is a thermodynamically efficient use of fuel. In separate production of electricity, some energy must be discarded as waste heat, but in cogeneration some of this thermal energy is put to use. All thermal power plants emit heat during electricity generation, which can be released into the natural environment through cooling towers, flue gas, or by other means. In contrast, CHP captures some or all of the by-product for heating, either very close to the plant, or – especially in e.g. Scandinavia and Eastern Europe – as hot water for district heating with temperatures ranging from approximately 80 to 130 °C. This is also called combined heat and power district heating (CHPDH). Small CHP plants are examples of decentralized energy.

Table 8-17 Combined Heat and Power

Characteristics	Operational consequences	Planning consequences
• Fuel cells in connection to industry, farms, residential homes, housing estates, etc. • Produce heat and electricity mainly for local/own use • Surplus is either sold or stored in batteries/reservoirs	Positive: • Same as Table 8-14	Positive: • Same as Table 8-14
	Negative: • Same as Table 8-14	Negative: • Same as Table 8-14

8.4.5 Hydro Power

Building of small hydro power stations have been very popular in Norway the last 10 years.

Small hydro is the development of hydroelectric power on a scale serving a small community or industrial plant. The definition of a small hydro project varies, but a generating capacity of 1 to 20 megawatts (MW) is generally accepted, which aligns to the concept of distributed generation.

Small hydro can be further subdivided into mini hydro, usually defined as 100 to 1,000 kilowatts (kW), and micro hydro which is 5 to 100 kW. Micro hydro is usually the application of hydroelectric power sized for smaller communities, single families or small enterprise. The smallest installations are pico hydro, below 5 kW.

Pico	:	< 5 kW
Micro	:	5 – 100 kW
Mini	:	100 – 1000 kW
Small	:	1 – 20 MW

Small hydro plants may be connected to conventional electrical distribution networks as a source of low-cost renewable energy. Alternatively, small hydro projects may be built in isolated areas that would be uneconomic to serve from a network, or in areas where there is no national electrical distribution network. Since small hydro projects usually have minimal reservoirs and civil construction work, they are seen as having a relatively low environmental impact compared to large hydro. This decreased environmental impact depends strongly on the balance between stream flow and power production.

Plants with reservoir, i.e. small storage and small pumped-storage hydropower plants, can contribute to distributed energy storage and decentralized peak and balancing electricity. Such plants can be built to integrate at the regional level intermittent renewable energy sources.

Table 8-18 Hydro Power

Characteristics	Operational consequences	Planning consequences
• Not adjustable hydro power generation without reservoirs • Produce electricity mainly for local/own use • Surplus is sold	Positive: • Same as Table 8-14	Positive: • Same as Table 8-14
	Negative: • Same as Table 8-14	Negative: • Same as Table 8-14

8.5 Demand Side Management (DSM)

The development is driven by the fact that – despite increased efficiency of electric devices – consumption is steadily rising some percent every year. While generation might not be much of a problem, it is the grid capacity that is a challenge [38]. New projects with renewable generation raise questions about the grid connection. The grids might soon face their limits, and intelligent DSM is one way to stretch these limits a bit further. DSM thus promotes distributed generation.

DSM includes everything that is done on the demand side of an energy system, ranging from exchanging old incandescent light bulbs to compact fluorescent lights up to installing a sophisticated dynamic load management system. DSM can be a “utility driven” or “customer driven” activity.

Depending on the timing and the impact of the applied measures on the consumer process, DSM can be categorized into the following (see Figure 8-1):

a) Energy Efficiency (EE)
b) Time of use (TOU)
c) Demand Response (DR)
d) Spinning Reserve (SR)

The quicker changes are processed and done, the more unwanted impact they have onto the customers' processes. The “processes” can be manufacturing output, pump power or even optimizing human comfort or health in a building.

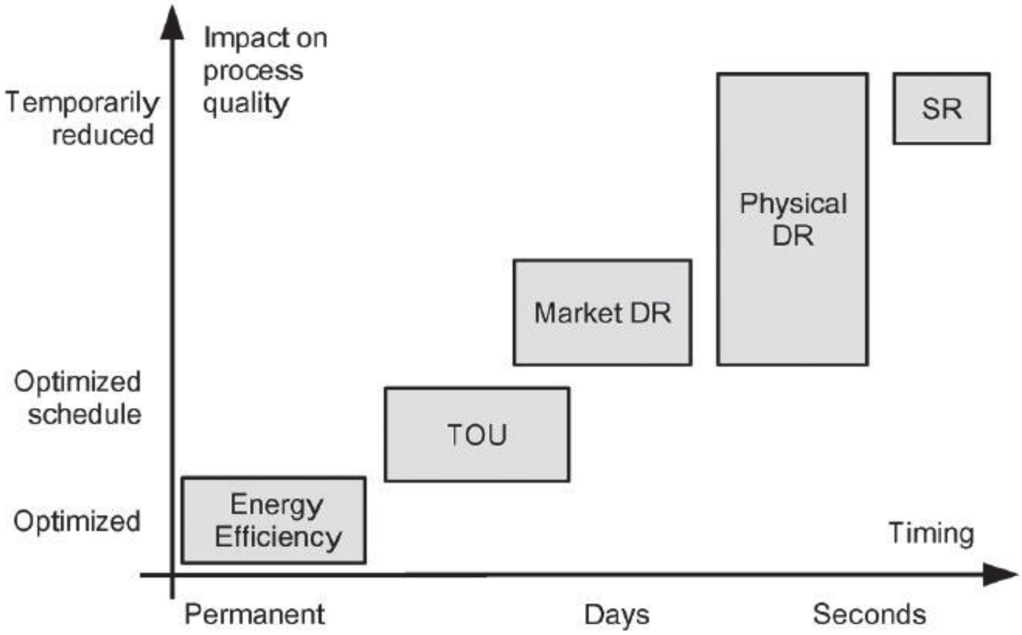


Figure 8-1 Categories of DSM [38]

End-users with flexible demand could be able to (or be willing to) participate in organized DSM solutions in service. Typical flexible demand is for electric boilers, water heaters and, in some cases, direct electricity space heating (in houses with alternative heating sources such as wood, oil, or gas stoves). Air conditioning could also be considered a flexible load, at least for shorter periods (a few minutes). This could apply as well to refrigerators and ice boxes (freezers).

Active use of flexible demand can reduce peak demand. To a certain extent, this is more beneficial than an increase in power generation. Reduced peak demand saves energy and reduces (or postpones) network investments.

These alternatives are discussed under this heading:
- Variable network tariffs
- Smart Homes
- Market-based balancing of power generation and consumption
- Energy Service Company (ESCO)

8.5.1 Variable network tariffs

The DSOs can use variable network tariffs to give incentives for the consumers to use energy when it is cheapest and for the producers to generate when it is most profitable.

Table 8-19 Variable network tariffs

<table>
<tr><th>Characteristics</th><th>Operational consequences</th><th>Planning consequences</th></tr>
<tr>
<td rowspan="3">• Several different tariff models are applicable
• Network tariff varies with available grid capacity.
• Network tariffs are based on energy and power consumption – not only energy consumption as today
• Electricity rates based on real time spot price</td>
<td rowspan="2">Positive:
• Reduces the use of energy and power in periods when the prices are high.
• The power part of the tariff may vary in fixed steps or follow the real time spot price.
• Energy consumption will level out
• Power consumption will be reduced
• Utilization time will increase
• The consumption during night may increase</td>
<td>Positive:
• Consumption varies with the electricity prices. This is not happening today because of monthly settlement.
• Different tariff models for different consumers gives different models for relationship between tariff and consumption.
• Available technology</td>
</tr>
<tr>
<td rowspan="2">Negative:
• The tariffs (energy and power costs) will affect the consumption. This means that the load prediction becomes more uncertain and the load models must be adapted to this change.
• Requires AMI
• The relationship between price and consumption need to be modelled</td>
</tr>
<tr>
<td>Negative:
• Billing every hour requires new systems for handling large amounts of data</td>
</tr>
</table>

8.5.2 Smart Homes

Consumers can install their own control system to manage energy and power consumption and generation based on information about network tariffs, market prices and their own consumption/generation. The purpose for the customers are minimizing their electricity bill (or maximizing their profit from their generation).

Table 8-20 Smart Homes

Characteristics	Operational consequences	Planning consequences
• Smart energy and power control in residential homes • Many technologies in combination - Photovoltaic (battery) - Solar collectors (water heating) - Wind turbine (battery) - Heat pump (heat and/or hot water) - Electric vehicle (battery, charging and storage) - Fuel cell (heat and electricity) - Biomass boiler (heat and/or hot water) - Storage (electric battery, hot water) - Smart control of consumption, generation and storage by price and availability	Positive: • Residential building or housing estate as a micro grid will give new and enhanced options. The options depends on available generating capacity and regulation possibilities. • Storage and generation reduces the consequences of grid outages.	Positive: • Residential building or housing estate as a micro grid will give new and enhanced options. The options depends on available generating capacity and regulation possibilities.
	Negative: • The dependency in electricity for management and control purposes increases. • Increased ENS / CENS? • Complex load situation – forecasting and prediction are difficult.	Negative: • Complex load situation – forecasting and prediction are difficult. • Dynamic grid operation • Difficult to make load models for long term power system planning - Variation - Forecasting (development) - Price dependency - ... • Available technology but somewhat immature yet • Expensive for the customer

DSM may be carried out directly by the TSO and DSO, but in the future it is believed this can be done by a third party, the ESCO (Energy Service Company). Peak demand reduction can be beneficial for the utilities in terms of energy loss reduction and postponement of new investments. The ESCO will take part in the balancing markets and share its profit with the customer and power supplier.

8.5.3 Market-based balancing of power generation and consumption

TSOs controls the power balance in the transmission system through generation bidding and load forecasting in different regulation markets. For the distribution grids, the DSOs can perform balancing in the form of congestion management. The DSO can arrange a local market and make agreements with consumers/producers regarding congestion of consumption/generation in strained situations. The DSO regulates/controls the load/generation according to agreements.

Table 8-21 Market-based balancing of power generation and consumption

Characteristics	Operational consequences	Planning consequences
• Generation and consumption are balanced by market signals (price/demand). • Generation and consumption can both be regulated. • Optimal solution is chosen.	Positive: • Can be used in strained situations to keep the lights on	Positive: • Can be used in strained situations to keep the lights on • Reduced ENS/CENS
	Negative: • Complex load situation – forecasting and prediction are difficult • Dynamic grid operation • Need continuous monitoring, management and control of the grid	Negative: • Complex load situation – forecasting and prediction are difficult • Dynamic grid operation • Immature technology for use in distribution grids. • Need larger regulating units (aggregators) which regulate load and generation and are acting in the energy market.

8.5.4 Energy Service Company (ESCO)

Instead of congestion management controlled by the DSO, an Energy Service Company can make agreements with many consumers and actively control parts of their load, like e.g. water heaters and heating cables, and offer controllable load in the national electricity market in the same way as regulating generation.

Table 8-22 Energy Service Company (ESCO)

Characteristics	Operational consequences	Planning consequences

• ESCO (Aggregator)
• Controls a lot of loads
  - Contracts with many consumers
  - Trades in the electricity market - selling controllable loads
• Reducing the total power demand
• Reducing costs for involved consumers and DNO/DSO
• May assist the DNO/DSO with load balancing in special occasions (strained situations)
	Positive:
	• Reduces the total power demand
	• Increases the utilization time
	• The consumption becomes more price sensitive
	• Interaction between DSO and ESCO – communication is important
	• DSO may buy services from ESCO
	• Customer satisfaction?
		Positive:
		• ESCO services may be used/bought by DSO in strained situations
		• Provides an overview of available flexible capacity in different geographical areas.

	Negative:
	• May risk that some customers are affected more often than others
	• If a consumer is 100 % disconnected by the ESCO, the DSO might see this as an interruption and thus calculate wrong values for ENS and CENS.
		Negative:
		• Available technology but today only used for industry and large loads.
		• Difficult to make load models for long term power system planning
		  - Variation
		  - Forecasting (development)
		  - Price dependency
		  - ...
		• Requires AMI
		• The ESCO needs direct control over part of the end-users load
		• Direct communication between ESCO and customer

8.6 Compilation of the consequences

Based on the list of positive and negative consequences for each element mentioned in Table 8-1 to Table 8-22, the consequences are summarized in Table 8-23 using color codes. Of the 22 mentioned elements, only one is considered to have only negative consequences to the grid. 11 elements are considered to have mainly positive consequences to the grid and 10 are considered to have both.

Table 8-24 compiles the consequences for planning and operation. Does the element affect load modelling, generation modelling or load-flow/stability/operation/maintenance?

Elements in the future smart grid will definitely contribute to improving the quality of supply to end users in the electricity distribution grid, but it will also provide a number of new challenges that need to be addressed in the distribution system planning, i.e.:

- The use of more automation and control equipment in order to utilize the grid better will provide stability issues
- Increased amount of connected distributed generation from renewables
- Increased use of energy efficient and power-intensive equipment in industry, business, social services and households will give greater fluctuations in the load-flow.
- Plus Energy Houses
- The prevalence of Electric Vehicles increases
- Increased use of sensors, metering and control systems provide a lot of data and information. It can be a challenge to utilize all the information and the opportunities it provides in a timely and satisfactory manner.

One important conclusion from this chapter is that new elements in the future Smart Grid will lead to increased uncertainty regarding future load flow and the need for grid capacity.

Table 8-23 Compilation of consequences for the grid

New components in the distribution grid	More accessible data	Smart solutions related to operation, monitoring and protection	Distributed generation (DG)	Flexible demand (DR, DSM)
1. SVC/STATCOM-D	1. Smart metering (AMI) – consumers	1. Phasor measurement unit (PMU)	1. Distributed generation in general (DG)	1. Variable network tariffs
2. Storage	2. Smart metering (AMI) – distribution transformers	2. Real time thermal rating (RTTR)	2. Photovoltaics (PV)	2. Smart homes
3. Electric Vehicles (EVs)	3. Sensors	3. Smart distribution transformers	3. Distributed wind power	3. Market based balancing of power generation and consumption
4. Energy efficient but high powered appliances		4. Control centers for distribution grids	4. Combined heat and power	4. Energy service company (ESCO)
5. Voltage booster		5. Micro grids	5. Hydro power	

Color codes:

- Only negative consequences for the grid.
- Both negative and positive consequences for the grid. The consequences are depending on the situation. May increase the load, but may also be a resource to reduce other problems (e.g. photovoltaics).
- Mainly positive consequences for the grid. The few (if any) negative consequences are negligible small compared to the positive consequences.

Table 8-24 Compilation of consequences for planning and operation

New components in the distribution grid	More accessible data	Smart solutions related to operation, monitoring and protection	Distributed generation (DG)	Flexible demand (DR, DSM)
1. SVC/STATCOM-D 2. Storage 3. Electric Vehicles (EVs) 4. Energy efficient but high powered appliances 5. Voltage booster	1. Smart metering (AMI) – consumers 2. Smart metering (AMI) – distribution transformers 3. Sensors	1. Phasor measurement unit (PMU) 2. Real time thermal rating (RTTR) 3. Smart distribution transformers 4. Control centers for distribution grids 5. Micro grids	1. Distributed generation in general (DG) 2. Photovoltaics (PV) 3. Distributed wind power 4. Combined heat and power 5. Hydro power	1. Variable network tariffs 2. Smart homes 3. Market based balancing of power generation and consumption 4. Energy service company (ESCO)

Color codes:

Load modelling

Generation modelling

Load-flow and stability. Operation & Maintenance.

The question is:
Is today's deterministic fit-and-forget methodology for distribution system planning shown in Figure 3-1 suitable for the future smart grid as well?

Grid dimensioning based on worst-case scenario will no longer be a viable alternative since generation from renewables vary with e.g. the wind or the solar radiation, and new energy efficient and high powered loads vary more stochastically than before. Consequences of this worst-case reinforcement practice will be poor utilization of the grid capacity and consequently high costs.

Although other relevant technical aspects such as congestion, voltage rise and reverse power flows are considered in today's fit-and-forget approach, it is mainly based on maximum generation – minimum demand scenarios that, for RES, do not occur frequently. While in some cases, the actual design of networks has been adapted to cater for distributed generation, this passive way of planning and operating of distribution networks has proven cost-effective in the last decades, it might in the future become a barrier for increasing penetrations of DG and non-conventional loads [11].

Distribution network operators (DNOs) will usually provide firm capacity access to medium-scale DG-plants (i.e. ability to produce up to the registered capacity at any time with a defined range of power factor capability) provided there is minor or no impact on the network (otherwise reinforcements will need to be paid for). This means that with each subsequent connection the hosting capacity of the network will be reduced, reaching its fit-and-forget limit soon. Some DNOs, in order to facilitate further penetrations, have also adopted non-firm connections where generators are tripped automatically (in a last-in first-out basis) after a network constraint is breached.

Connection of small-scale (or domestic-scale) distributed generation, commonly in the form of photovoltaic panels, micro hydro power or micro combined heat and power (CHP) have, in general, different rules. Such installations will basically need to comply with minimum standards and register the connection as part of, for example, a fed-in-tariff scheme. This means that the DNO has little or no control over the penetration of this type of connections. As a consequence, high penetrations of small-scale DG can quickly and more easily lead low-voltage circuits to have technical issues similar to those found upstream.

DNOs subject to unbundling rules cannot invest in medium-scale generation facilities and are meant to provide DG owners with cost-effective connection means, irrespective of the technology or geographical location. Domestic-scale generation and new loads are only required to comply with the corresponding standards, but do not need to apply for a connection. In this context, the uncertainties in planning consents and financial support surrounding medium-scale generation and loads pose DNOs with major challenges as to what, where and when to reinforce the system in order to facilitate the transition to a low-carbon economy without the risk of stranded assets. This lack of certainty and planning coordination translates into DNOs often connecting DG plants in the above mentioned fit-and-forget, case-by-case manner. Thus, any sophisticated solution, albeit potentially more cost-effective for society in the long term, is left behind.

In order to facilitate the integration of these low-carbon technologies, the use of a more *active* approach for managing distribution networks (including both network elements and participants) has been proposed in the last decade by academia and industry. Due to the increasing penetration of distributed generation connected to the MV, particularly in Europe, significant interest was first given to coordinated control approaches that could mitigate voltage or congestion issues [39], [40] and [41], albeit as standalone solutions. Similar concepts evolved also considering for instance multiple distributed generation plants (e.g. wind farms) [42], electricity storage [43], and demand side management [44]. However, most of these works focus on the operational challenges rather than planning aspects.

The growing vision of the need of active distribution network approaches led in 2006 to the creation of the CIGRE Working Group C6.11 on the "Development and Operation of Active Distribution Networks". This

Working Group highlighted the fact that active networks affect all planning activities as, for instance, DG affects load forecast and active management affects the design of the system. Consequently, DNOs need to move from the planning of the passive paradigm of distribution towards one where integration – not simply connection – of DER is taken account of, at a reasonable cost.

A survey carried out by the WG C6.19 Survey Task Force [44] to determine the state-of-the-art and identify which developments are needed for the planning of active distribution network, showed that 90 % of the respondent utilities follow traditional steps of the typical planning process. Although there are significant differences in how these activities are done, it is clear that [44]:

- The planning process at present hinges very strongly on data related to customers usage and city planning to form accurate load forecasts, which is the main input into the technical planning portion of the study.
- At present, little or no consideration is given to distributed generation or demand side integration in the development of these forecasts.
- While of interest to many utilities, demand-side integration and active distribution network concepts fail to be given serious consideration by utilities as viable alternatives in the planning process.

Given that there is a lack of planning techniques for active distribution networks, this report aims at identifying a suitable planning method that could ensure the transition to future distribution networks. Since loads and generation seems to become more variable and more stochastic than today, the planning method should involve individual and probabilistic models for loads and generation. This is consistent with the conclusion in Chapter 4.6.

PART III – Planning methodology for the future smart and active distribution grids

9 Active distribution system (ADS) planning

According to previous chapters 5, 6, 7 and 8, the distribution systems are transforming from passive networks to active networks. Most of the text in this chapter is taken from these two reports:

- *Active Distribution System Management, A key tool for the smooth integration of distributed generation*. A EURELECTRIC paper, February 2013, Per Hallberg (chair). [45]
- *Planning and Optimization Methods for Active Distribution Systems,* CIGRÉ Working Group C6.19, August 2014, Fabrizio Pilo (convenor). [11]

These reports are essential and form a good basis for the work done in this thesis. Some of the figures in this thesis are slightly modified from the original version found in the two mentioned reports.

9.1 Active distribution systems

There is no one-size-fits-all solution because distribution networks are rather heterogeneous in terms of grid equipment and DG density at different voltage levels. Every distribution network should be assessed individually in terms of its network structure (e.g. customers and connected generators) and public infrastructures (e.g. load and population density). Nevertheless, the needed development towards future distribution systems which meet the needs of all customers can be described in the three schematic steps pictured in Figure 9-1: from (1) passive network via (2) reactive network integration to (3) active system management.

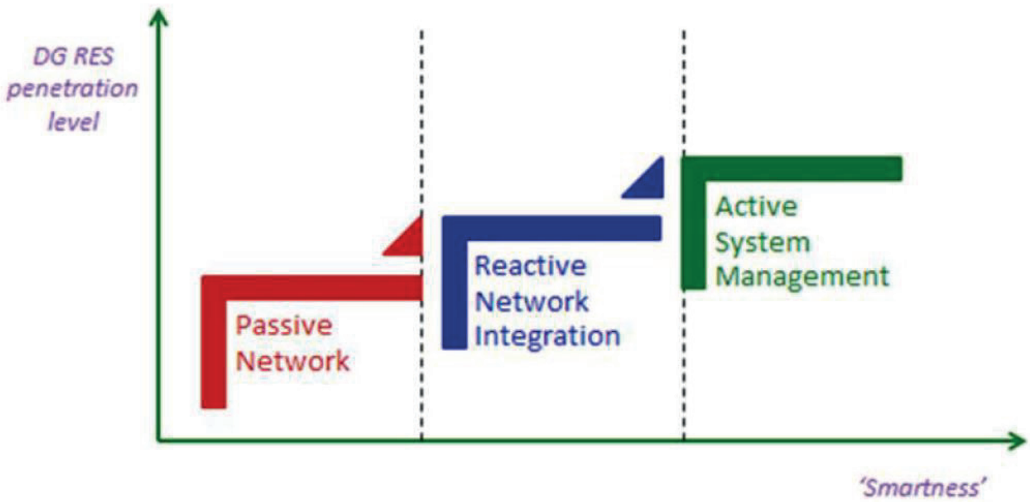


Figure 9-1 Three-Step evolution of distributed systems [45]

(1) **Passive distribution networks** make use of the so-called 'fit and forget' approach. This approach implies resolving all issues at the planning stage, which may lead to an oversized network. DSOs provide firm capacity (firm grid connection and access) that may not be fully used anymore due to local consumption of the electricity produced by DG. This approach has the advantage of requiring low flexibility, control and supervision of network operation, but is only possible for a network with very low DER penetration. Once DER penetration rises, the system cannot be designed to cater for all contingencies without very significant investment in basic network infrastructure, making this approach less economical.

(2) **Reactive network integration** is often characterized by the 'only operation' approach. This approach is used today in some countries with a high share of DG. The regulation requires connecting as much DG

as possible with no restrictions. Congestions (or other grid problems) are solved at the operation stage by restricting both load and generation. This solution could restrict DG injections during many hours per year and lead to negative business case for DG if they are not remunerated for the restrictions. This solution is however not allowed in Norway (see Chapter 4.7 *Generation modelling*, page 32). Already today, some 'front-runner' countries with high DG penetration levels can be considered as having reached the interim 'reactive network integration' stage at which DSOs solve problems once they occur (largely only in operation).

(3) **The active approach** would allow for interaction between planning, access & connection and operational timeframes. Different levels of connection firmness and real-time flexibility can reduce investment needs. The existing hosting capacity of the distribution network can be used more optimally if other options including ICT, connection & operational requirements guaranteeing adequate performance of DER towards the system (i.e. via grid codes) and market-based procurement of ancillary services from DER are considered. Operational planning of distribution networks (similar to that at transmission level) would be in place in networks with high DER shares in order to incentivize dispatch in a way that is compatible with the network. Improved network capacity planning and congestion management at distribution level at different times and locations will be required to maximize the level of generation which is injected in the most economical way for all parties, while maintaining network stability. DSOs must have tools for overseeing maintenance of network standards. Additionally they should have the possibility to buy flexibility from DG and load in order to optimize network availability in the most economic manner or to manage network conditions which are beyond the contracted connection of the customers. DSOs should have the possibility to buy flexibility from DG and load on so-called 'flexibility platforms' in order to solve grid constraints. The network reinforcement could be deferred until the moment when it becomes more cost-effective than the on-going cost of procuring reliable services from DER.

Table 9-1 describe this three-step evolution of distribution systems in more detail regarding:

- Network development (planning, connection and access)
- Network operation
- Information exchange
- Technical development

Table 9-1 Three-Step Evolution of Distribution System in detail [45]

Layer		Passive Distribution network	Re-active distribution network	Active distribution system management
Network development (planning, connection & access)		Fit and forget approach: everything "solved" at the planning stage	Only operation approach: Connection with no restrictions and solutions at the operations stage Or Fit and forget approach	Combined planning and operational solutions: Active capacity and loss management through commercial interaction with market actors selling flexibility services Connection and access criteria combined with operation tools to manage DER
Network operation		Low monitoring & control of DG RES, often only by the TSO Missing rules & services for DG contribution to quality of service, security of supply & firmness	Emergency generation curtailment by DSO. Active voltage control distribution networks. Grid codes for DG to meet connection criteria and be able of voltage based control and reactive power contribution.	Flexibility support from DSO to TSO and from TSO to DSO when required New system services for DSOs arranged via commercial ancillary services and grid codes.
Information exchange		Little information exchange from TSOs/DER to DSOs (small DER do not send information)	High-level information exchange from DSOs/DER to DSOs	Structured and organized off-line and where needed real-time information exchange (standardized interfaces with DER required)
Technical development	Network	Limited monitoring & control capabilities (usually only HV) Conventional SCADA for HV network and DMS/OMS for MV and LV	Increased monitoring and control at HV & MV via telecommunications SCADA/DMS/OMS with the measurement of certain new DG	Increased monitoring, simulation and control down to LV via telecommunications Advanced Distribution Management Systems for DSOs/ SCADA and Distribution Management System (DMS)
	DER	DG often not prepared for power factor control Storage & EV not developed	Enhanced DG protection systems/ inverters enabling voltage & reactive power control	Configurable settings: e.g. protection / fault ride through settings, voltage droop Presence of storage & EVs

Active system management schemes range:

- From the innovative standalone operation of a single network element (e.g. on-load tap changer) without the need of remote communications
- To the extensive use of ICT infrastructure in order to manage network elements and participants/actors altogether, according to the corresponding application of the scheme

ADS approaches have the potential to tackle many network issues in the short to medium term, but it is important to emphasize that at some point in the planning horizon, traditional investments will be needed.

Chapter 8 provides a more detailed overview of some new elements in the future distribution grids and how these elements will affect the operation and planning of distribution systems.

9.2 General framework for ADS planning

The transformation from the current passive distribution network to the future Smart Grid paradigm aims at applying at distribution level (improved and tailored) techniques and solutions that have been used for decades in transmission systems. These techniques and solutions could in principle, have been used in distribution systems in decades as well, but they have so far been too expensive while the needs for such solutions in the distribution systems have not been so great because of the absence of generation. The advent of more advanced distribution networks is progressively changing distribution planning objectives. Maximum exploitation of existing assets and infrastructure will become priority, and their operation will be much closer to their physical limits than in the past. Indeed, the future philosophy of distribution network planning will consider less traditional network investments in favor of cost-effective Active Distribution Network solutions such as generator dispatch, demand side integration, control of transformer taps, etc. in order to manage network issues.

Consequently, it is crucial that modern planning tools integrate ADS solutions in the set of feasible alternatives to identify the best technical and economic balance between traditional network reinforcements/expansion and active approaches. To this end, **the representation of loads and generators cannot longer be based on snapshots of the operating conditions (e.g. max generation/min demand and min generation/max demand) as commonly assumed by current planning methods and tools.** There is the need of adopting time-series (or time dependent) models in order to capture the operational aspects of different network elements. In addition, the costs associated from the implementation of ADS should also be defined, taking into account the dependencies on the ICT infrastructure and the corresponding regulatory environment. All these aspects radically affect methods and techniques used for distribution network planning.

To adequately cater for ADS alternatives, probabilistic approaches should be considered to capture the more uncertain behavior of demand and generation, and the assessment/comparison of alternatives should be based on one or more objectives. Figure 9-2 shows a general framework for planning based on a figure proposed in [11].

The main novelty is represented by the blocks for evaluating the risk of constraint violation and the use of active management (no-network solutions) over traditional network solutions. A macro code for distribution planning can be based on the following steps:

1) Definition of the planning study. This includes defining input data (technical, financial, economic, etc.).
2) Load and generation modelling. Pre-processing of ADS customer data (loads and generators) to capture time-dependent features.
3) Generation of planning alternatives, i.e. a set of possible expansion/development/building alternatives.
4) Network calculations and risk evaluation.

5) Active distribution network implementation. If operation issues are to be expected in the planning period, try to solve them with an ADS solution. If this is not possible, resort to traditional network approaches.
6) Multi-Objective alternative evaluation. Assessment of each alternative according to the specific problem, based on e.g. network calculations and reliability analysis, possibly with a multi-objective approach.
7) Selection of the best alternative or the set of best options.

Some of these steps will be explained further.

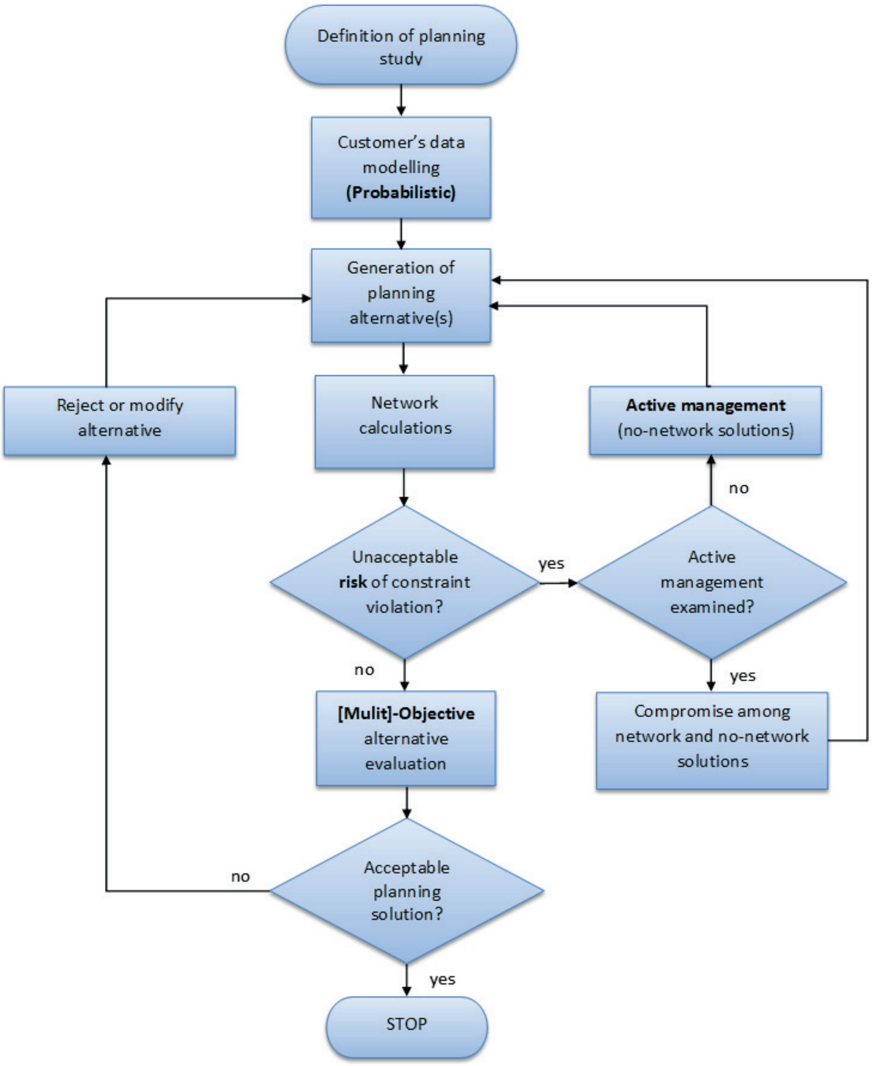


Figure 9-2 Probabilistic planning methodology for electrical networks (based on a figure found in [11])

9.2.1 Load and generation modelling

Of all the parameters affecting network design and timing of major reinforcements, the load and generation forecast is the most sensitive because erroneous estimations could lead to considerable drawbacks. Over-estimation of load can pre-date investment and cause equipment over-sizing. Under-estimation provokes early degradation of the quality of service due to untimely upgrades. Adequate knowledge of load profiles is essential in two planning features:

- The identification of the maximum stress conditions – Economically, any system reinforcement should be planned on the basis that further reinforcement will not be required for a given number of years.
- The determination of energy losses – the peak power losses affect the sizing of network's equipment, while annual energy losses increase the DNOs operating costs.

Since the pattern of the electrical demand of each customer and the pattern of the generation from each DG/DER is usually not accurately known, it might be necessary to calculate system loadings on a statistical basis, either considering existing loads or forecast values.

The main drawback of today's deterministic approach (described in Chapter 4), is that the distribution network is designed assuming worst-case conditions as certain, even if actually they might have a very low probability of occurrence. Table 9-2 summarizes traditional, current and modern modelling of loads and generation.

Table 9-2 Data modelling for distribution network planning studies [11]

Traditional	Current	Modern
Daily load curves were collected to classify several categories of loads and used to identify the worst condition, i.e. maximum demand (coincidence factors). Constant/predictable generation (not RES) was considered as negative load. Unpredictable generation (RES) was considered only for the estimation of technical losses. In other contexts set to zero.	Due to a higher penetration of DG, all generation technologies are considered. However, uncertainties of RES are not represented. Two worst-case conditions are defined: 1) Max load – No generation 2) Min load – Max generation These conditions are considered as certain even if they will appear rarely (particularly for renewables).	Daily load curves and daily generation curves have to be explicitly modelled. Some typical operating conditions need to be recognized together with their relative probability of occurrence. Importance of chronological representation (time series).

These simplified representations are unsuitable for the planning studies of the future active distribution networks. In order to capture the operational aspects that can affect the planning stage, the time variability of demand and generation has to be explicitly represented in the planning calculations. The development of smart metering will also help DNOs to collect actual load profiles from every node. **One open question is how high the corresponding time resolution should be** (e.g. every minute, every 15 minute, every half hour, etc.). The answer depends on the characteristic of the control strategy analyzed and the impact it could have on the results of the planning studies. For instance, the control cycle that some DER can offer to the system usually requires a time step in the range of seconds, but it has negligible effect at the planning stage. The analysis of automatic voltage control relays (i.e. on-load tap changers) and other voltage regulation for the whole distribution network can be carried out with different time steps: one minute, five minutes, fifteen minutes or one hour [14]. All these discretization options are useful at the planning stage to highlight the capability of the voltage regulation to prevent some constraint violations, deferring possible network investments. A finer discretization can capture some extreme operational conditions that would be smoothed with a rough representation but, generally, these situations are sporadic and the risk of disregarding them in the planning decision can be acceptable. **For the above reasons, a time step of one hour is commonly used to represent load and generation profiles and to analyze the impact of operation strategies in the planning studies**.

9.2.2 Network calculations and risk evaluation

The several new uncertainties that characterize the future electrical distribution system suggest the use of probabilistic models to represent the typical planning data and the introduction of the risk concept in the choice of the planning alternatives. These uncertainties can be modelled by suitable probability density functions, if the probabilistic data for the input variables are available. Depending on the stochastic distributions assumed (i.e. Gaussian, Beta, Rayleigh, etc.), network calculation can be performed by specific probabilistic load flow algorithms or the more general Monte Carlo simulation approach. **Instead, when the probabilistic data are unknown, the planner can draw out possible scenarios based on experience and knowledge or, for instance, using fuzzy set theory**. The results of these calculations are the stochastic representation of the nodal voltage and branch current variables, through which the technical constraints can be verified with a relative confidence (acceptable risk of violation). For instance, the planner may define an acceptable probability of overload occurrence (e.g. 1 %) and, by using the probability distribution of the branch current, the planner can determine the value of current that has this probability of occurring. If this value is greater than the thermal limit, the corresponding branch has to be upgraded. With a more risky choice (maximum overload occurrence of 10 %), this refurbishment could be avoided.

It should be recognized that probabilistic calculations are sometimes complex and cumbersome and it is often not easy to determine the proper modelling of distribution systems, particularly when strong correlations exists among the stochastic variables and external correlations are influenced by market or by operation control centers. Moreover, a strong additional difficulty in the probabilistic load flow problem resolution is given by the non-linearity of the load flow equations. The only way to solve this severe problem, with different density functions, complex correlations and non-linear combinations of the stochastic variables, is the resort to **Monte Carlo simulation methods**, particularly if parallel computing capabilities are exploited. However, also with parallel computing, this precise approach causes a dramatic increasing in the computation time, especially for planning purposes where calculations has to be repeated several times within an optimization procedure (for network design or DER allocation).

Example:
A branch current (I_b) is described as a normal distribution function with expected value (μ_b) 100 A and standard deviation (σ_b) 150 A. The distribution density and the cumulative probability of the distribution function for the branch current is shown in Figure 9-3. The 50, 90, 95 and 99 percentiles are marked in the figure. The 99 percentile in this example tells us that there is a 99 percent probability that the branch current will be below 449 A, or a 1 percent probability that it will be higher than 449 A.

If the thermal limit for the branch (e.g. cable) is 400 A, there is about 2.3 % probability of overload occurrence. If this is considered an unacceptable risk of overload, actions like e.g. introducing active management or grid reinforcement, must be taken to reduce this risk (according to Figure 9-2).

[14] The Norwegian Regulations on Delivery Quality (FoL) has limits for 1 min rms, while EN50160 has limits for 10 min rms.

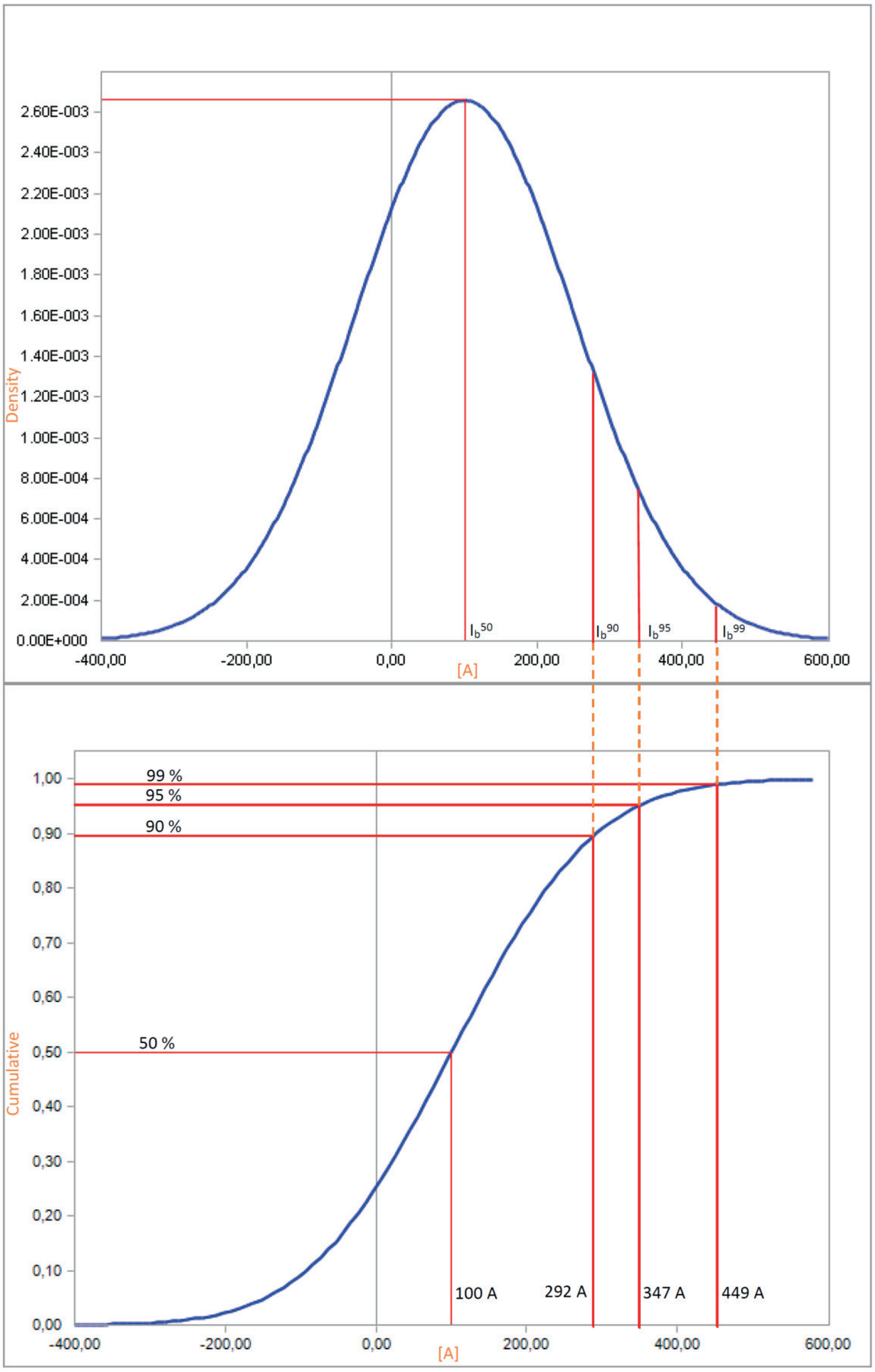


Figure 9-3 Example - Probabilistic network design, based on the concept of acceptable risk

9.2.3 Active Distribution Network Implementation

Generally speaking, the control of a power system is executed by means of two categories of actions:

- Those continuously applied during the ordinary network operation, for the preservation of a prefixed quality of service and for the efficiency improvement of the system (e.g. frequency control, voltage control, power flow management for energy losses reduction, reactive support, etc.).
- The ones execute occasionally to satisfy operational constraints for normal and N-1 contingency situations (e.g. generation curtailment, demand side management, on-line network reconfiguration, intentional islanding, innovative and coordinated protection scheme, etc.).

The first step in the integration of the operation in the ADS planning is the identification of which options have an effective impact on the planning analyses and need to be represented. **Frequency and voltage controls** have a small time constant, requiring the use of small time-step in the time-series representation of loads and generators, and often they are zero-energy services (particularly for frequency), determining no significant changes in the expected values of nodal voltages and branch currents. Continuous voltage regulation applied to compensate the variability of the renewable productions can reduce the standard deviations of these electrical variables. Therefore, these kinds of control have in general very low impact on planning studies. For sure, frequency control can be disregarded, while it could be useful trying to model in the probabilistic network calculations the voltage regulation service offered by some energy resources (e.g. energy storage) by means of a negative linear correlation with RES. However, if offered by third parties to the DSO and TSO, these services affect the revenue of the investments in DER. Indeed, assuming an over-dimensioning of the energy resource (or of its electronic converter), multiple benefits can be captured from the same device (e.g. energy storage can earn from the load levelling service and the simultaneous local voltage regulation service).

Power flows management, instead, strongly influences the network efficiency (in term of Joule losses) that constitutes a fundamental term of the distribution network OPEX. **The reactive support** for the HV system will be an important ancillary service of the future ADS that transforms, from TSO point of view, the distribution systems from pure energy sinks to participating actors. This control strategy may influence the allocation and sizing of DERs, the revenue of the DER owner (depending on the regulatory environment), and even the network expansion plan.

Almost **all the operation strategies used to solve contingencies** have a direct impact on the CAPEX for upgrading (investment deferral), due to the direct control of the energy production and/or consumption or the temporarily release of the technical constraints. It is worth noting that the most of the upgrading investments came from the “N-1” security analysis.

Only the **Intentional Islanding** and the **implementation of innovative protection schemes** have a major impact on OPEX by means of their capability of improving the continuity of the supply and the customer’s reliability indexes. For this reason, these two options have to be considered separately during the reliability analysis of the planning solution rather than with the network calculation.

9.2.4 Multi-Objective alternative evaluation [11]

In the uncertain scenario that characterizes the future ADS, a Multi-Objective (MO) approach proves to be useful for the distributors compared with the traditional single objective function of minimizing the overall network cost. In fact, the impact of several new technologies and control architectures required by the ADS is hard to characterize exclusively in terms of costs, also due to the lack of clear rules that should govern the active management (for instance, the remuneration for ancillary services). Therefore, it is easier and more effective to keep separated the various and non- homogenous objective functions by comparing known costs with advantages of the ADS solutions measured in terms of specific performance indexes. Moreover, the liberalization of the electricity market has broken the monopoly of the players involved in the power system, adding to the electric utilities new players and stakeholders like the Regulator, which represents the interest of the civil society and wants to favor the integration of RES at reasonable costs, the generator owners that wish to maximize the profits of their investments, and also aggregators of active demand and small generation. The need to find compromise solutions for the conflicting goals of these system stakeholders, and the difficulty of defining a unique objective function, is another significant reason that leads to MO approaches.

The goal when solving a multi-objective optimization problem is finding non-dominated (Pareto optimal) solutions and quantifying the trade-offs in satisfying the different objectives. A solution belongs to the Pareto set if no improvement is possible in one objective without worsening in any other objective. In the literature, the MO methods are divided into two main groups. The first group makes use of single-objective technique and a priori information. By changing the master objective function several solutions of the Pareto set are identified. This procedure is known as the "**classical approach**" and it asks the user to perform an a priori decision making, by assigning preferences to the objectives under consideration. The ε-constrained and the weighted-sum methods are the most widely used in this category and provide one single least-cost solution at a time. One "master" objective is optimized and the rest considered as constraints, or alternatively, all objectives are aggregated into a single objective function that is optimized. Deep knowledge of the problem is required to define adequate master objectives and constraints levels or aggregation method and weights, respectively. The need to make such a priori decision is a drawback of the classical approach since it is in some cases too much dependent on the planning engineering personal point of view.

The complexity of the future distribution system suggests the use of "true" MO algorithms that produce a set of Pareto optima solutions without the use of subjective weights. These algorithms fall in the group of multi-objective optimization methods based on **Evolutionary Algorithms (AE**). EA manages sets of possible solutions simultaneously, and permit identification of several solutions of the Pareto front at once. During the past twenty years a large number of Multi-Objective Evolutionary Algorithms (MOEA) has been developed. The main classification of these algorithms is in first generation or second-generation MOEA, the latter being characterized by the use of elitism. At present, two of the most recognized algorithms of the second generation are the Non Sorting Genetic Algorithm II (NSGA-II), and the Strength Pareto Evolutionary Algorithm 2 (SPEA2). These algorithms allow generating a rich set of trade-offs between the examined objectives, do not require a priori preference articulation and develop concave portions of the Pareto approximate front.

Multi-Objective programming is a powerful tool, but one of its strengths could also be interpreted as a weakness: providing more than one solution, it leaves their interpretation open to the subjectivity of the planner, rather than to objective roles. For this reason, this modern approach has to be always combined with the application of **Decision Making tools** that assign a fitness value to a planning solution representing the overall goodness or risk of its implementation. These tools can be based on the probability choice method, which minimizes the expected costs of each alternative in all the scenarios, or on the risk analysis, which minimizes the regret felt by a Decision Maker when the decision he had made was not optimal, given the future that in fact has occurred. A third approach has also been proposed in the Literature that, resorting to the stability areas concept, combines the two aforementioned ones and helps to recognize the best solution when it is difficult to assign a probability of occurrence to each scenario.

9.3 Scheduling for the adaption of the new planning tools

In the previous section, a possible course has been chartered for the evolution of the planning tools of the future distribution systems, highlighting the main points of improvement against the traditional planning procedures. These key features that modern distribution planning tools should process, their suggested implementations and the relative advantages and disadvantages are summed up in Table 9-3.

Table 9-3 Summary of the suggested improvements to the distribution planning tools [11]

Key points	Suggested improvement	Pros & Cons
Load and generation modelling	Classification	+ Implicit estimation of the occurrence probability of different operation conditions - Finer classification boosts computational burden - Difficult modelling of chronological aspects
	Daily patterns	+ Easy modelling of chronological aspects - Explicit adoption of suitable pdf
Probabilistic approach	Probabilistic Load Flow calculations	+ Allows dealing with uncertainties of RES production and load demand + Risk management of constraint violations - Need of simplifications to avoid computational overburden
		+ Allows adopting simple analytical expressions for the Probabilistic Load Flow - Imperfect modelling of RES production
Multi-Objective approach	Evolutionary algorithms (NSGA-II or SPEA2)	+ Simultaneous identification of several solutions of the Pareto set + No a priori knowledge of the objectives - High computational burden
ADS solutions integration	Linearized OPF separated from Probabilistic Load Flow	+ Reduced computational burden + Permits adoption of probabilistic approach

Even if it is generally established that the transformation of the distribution network planning procedure is needed to correctly cope with the growing presence of renewable energy sources and to suitably plan the evolution towards the active management of the distribution system, it is unlikely that current utilities are ready to drastically change all their consolidated routines at once. Instead, in order to be easier accepted and adopted, this radical change should be gradual, by introducing the novelties one at a time, where possible (Figure 9-4). Moreover, each innovation of the planning procedure should be sustained by ad hoc business cases that provide its benefits (improvements) in comparison with the traditional one.

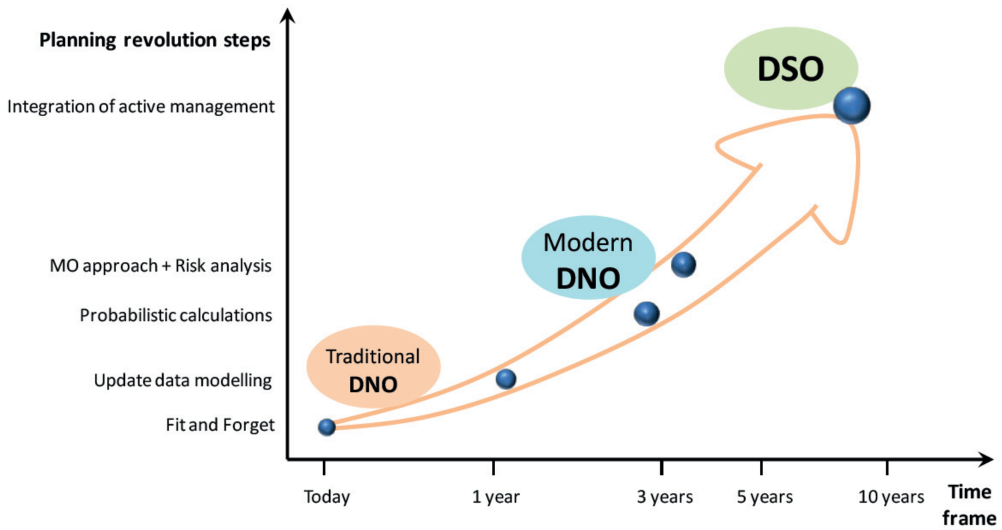


Figure 9-4 Scheduling for a gradual revolution of the distribution planning tools [11]

Therefore, looking back on the general framework proposed in Figure 9-2, a possible scheduling of the actions to take for this planning revolution can be identified by the following steps.

1. *Updating load modelling*. The first move should be a critical analysis and a potential update of the load models used by utilities, often based on measurements taken some decades ago. Starting from actual measurements of their customers and classifying the various operation conditions, it would be possible to apply directly the traditional planning tools to most of these conditions, neglecting those outside. This action could be implemented quite immediately, when measurements are available.

2. *Probabilistic calculations*. The second move could be the more difficult because it requires dealing explicitly with the uncertainties introduced by the RES productions and the behavior of the new loads (Electric Vehicles). The utilities should change their perspective to the planning problem by moving from deterministic to probabilistic network calculations and adopting the risk concept of constraint violation. Even still considering only traditional network solutions (system reinforcements), this improvement will allow utilities to look at RES no more as a problem but also as a resource. In any case, this action requires a strong modification of the traditional planning tools and it could be implemented reasonably in the medium-term.

3. *Multi-Objective optimization and Risk Analysis.* This third step is not strictly dependent on the previous one, because it is unrelated from the approach (deterministic or probabilistic) used for the network calculation. Therefore, it could be adopted also before the aforementioned second step. However, uncertainties are still important in this stage, from the side of the planning scenario. Moreover, due to the obvious need of the DNO to select one planning alternative in the Pareto set, the adoption of the Multi-Objective approach is always combined with suitable risk analysis methodologies.

4. *Active Management Integration.* In parallel to the previous steps, researchers and pilot projects on the implementation of the ADS will be carried on demonstrating, as expectable, the advantage of such distribution system evolution. In the meanwhile, also the National Authorities will have the time to define suitable regulatory environments for the effective implementation of an active management of the distribution system. Therefore, in five to ten years distributors could be ready to evolve their status from simple DNO to modern DSO.

Obviously, the illustrated time frame is depending on the particular conditions into which each utility operates. There are situations of low presence of DG and absence of advanced metering systems, where the period of this evolution could be longer. On the other side, some utilities have implemented or are implementing specific smart metering projects and they are already facing operational problems due to a huge penetration of RES (e.g. voltage variations and inversions of power flow in the substation transformers). Thus, they have to plan expansion of their networks and the adoption of these new planning procedures could be hastened.

10 Probabilistic models for load and generation with the use of data from smart meters

Good and reliable models for the variation and development of loads and generation connected to the grid today and in the future, are essential for the long-term development of the distribution and transmission grid. Poor models will probably result in a large difference between the future estimated (calculated) and real loads/generation and this again will result in wrong decisions and over- or underinvestment in the grid.

The ongoing and continuing increase in grid connection of distributed generation from renewable energy sources and change in consumption pattern will make the power flow more unpredictable and stochastic than before. Generation from renewables is normally unregulated (e.g. solar and wind) and will vary a lot. Increased use of energy efficient but power-intensive equipment like heat-pumps, electric vehicles and induction cookers together with time-varying tariffs for electricity use will affect the consumption pattern for each consumer. The consumption will also vary a lot more than before because of this. Automation and control systems together with new tariffs (if they are designed in a timely manner) can level out some of these variations in both generation and consumption, but it can also be the other way – amplifying the variations.

Increased uncertainty regarding future load flow and need for grid capacity means that more efforts must be used in load/generation modelling in the future. New methods should be probabilistic instead of deterministic as today.

The increased use of sensors, metering and control systems provide a lot of new data and information. It can be a challenge to utilize all the information and the opportunities it provides in a timely and satisfactory manner. Data from new smart meters will be essential in future load modelling. This chapter describes how the load modelling can be changed for the better in the future with the use of data from the new advanced metering systems.

10.1 Load modelling with the use of data from smart meters

According to a requirement from the Norwegian regulator, smart meters will be implemented in Norway within 2019-01-01. This will give the DSOs a lot more information about the behavior of each load/customer. From having unreliable information about monthly or maybe only yearly energy consumption, smart meters can give information about energy consumption every hour or up to every 15 minutes. Smart meters can also provide information about maximum load, maximum and minimum voltage, interruptions, and other voltage quality parameters. This new information should be used to make new and improved load models, both for short term purposes (operational planning) and for long term purposes (power system planning and long term development of the grid).

Load modelling with the use of data from smart meters can be done in many ways (see also chapter 9.2.1). Future load models must take into account the increased uncertainty in load and load-variation. The loads tends to be more energy efficient and power consuming, i.e. more stochastic in character. **As a part of this PhD-work a new method for load modelling is developed.** The method is briefly described and compared to today's method in Table 10-1.

In the developed method, every load/consumer is modelled individually based on temperature corrected metered hourly energy consumption in kWh/h for the last three to five years. More frequent values can also be used if data exists, e.g. 15-minute values. Individual models takes into account every type of electrical equipment used by the individual consumers and there is no need to have detailed information about the appliances used /installed (EV home charging station, induction cooktop, heat pump or any other high powered appliances).

Table 10-1 Load modelling – Description of the new method using data from smart meters

Description	New method with smart meters	Old method without smart meters
Modelling of expected load	Expected load for every customer modelled individually.	Expected load modelled for just a few customer categories (e.g. household, office building, industry, agriculture, school, etc.)
Variation curves for describing expected load	From one and up to seven daily variations for each month	From one and up to seven daily variations for each month. Usually two (workday and weekend/ holiday)
Modelling of uncertainty	Individual stochastic variable described by a distribution function.	Possible but usually not used. If used, then only on category level.

Figure 10-1 shows a flow-chart describing the load modelling process with the use of data from smart meters in more detail. The modelling process is described in more detail in Figure 10-1 and in the chapters 10.1.1 to 10.1.4

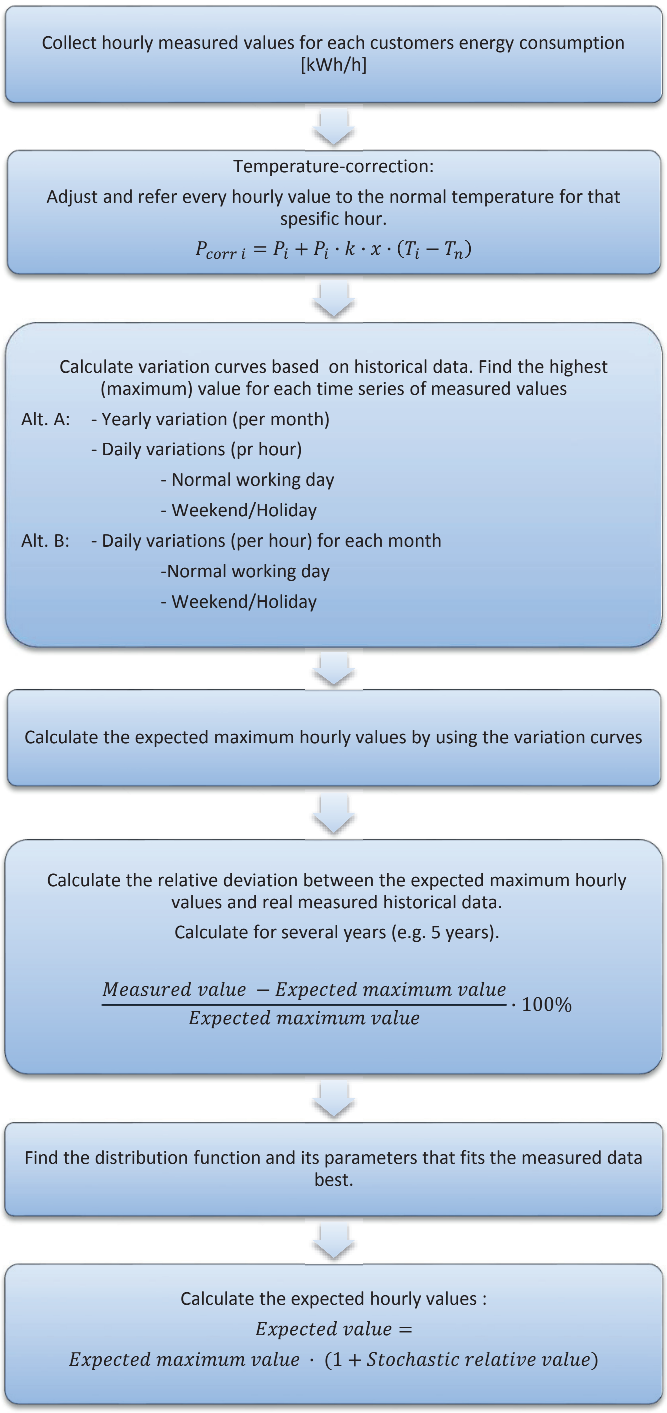


Figure 10-1 Flow-chart - Load modelling with the use of data from smart meters

10.1.1 Temperature correction of hourly metered energy consumption

The method for temperature adjustment described in Chapter 4.2, is used to adjust the temperature dependent part of the annual energy consumption by using the relation between Heating Degree Days for a normal year (HDD_{normal}) and the Heating Degree Days for the actual year "I" (HDD_i). When adjusting hourly values, the method should instead use e.g. the relation between the metered energy consumption for one specific hour, the actual temperature that specific day and the normal temperature for the same day.

Since the temperature dependent part of the energy consumption in Norway is mainly related to space heating during the cold months, only hourly metered values for the period November – April needs to be temperature adjusted. The following formula can be used for temperature correction of kWh/h (or kW-values) related to normal temperature:

$$P_{corr\ i} = P_i + P_i \cdot k \cdot x \cdot (T_n - T_i) \qquad (10\text{-}1)$$

Where:

- $P_{corr\ i}$ = Temp. corrected kWh/h-value hour "*i*"
- P_i = Measured energy use hour "*i*" (kWh/h)
- k = temperature dependent part of the energy use
- x = describing the temperature sensitivity of the temperature dependent part of P_i (° C^{-1})
- T_i = average for the last three days (3-day average) of measured temperature, day "I"
- T_n = Normal daily mean temperature for the specific day

Examples of temperature dependency factors (k) can be found in Table 10-2. The temperature sensitivity (x) for the temperature dependent part of the consumption can be set to 0,05 according to [14].

Table 10-2 Temperature dependency (example from www.enova.no)

Type of building	Older than 1950	1951-1970	1971-1988	1989-1998	1999-2008	2009-2011	2012-2014	Passive house
Small house	0,75	0,70	0,60	0,50	0,50	0,35	0,30	0,25
School	0,65	0,60	0,55	0,50	0,45	0,40	0,35	0,30
Hospital	0,45	0,40	0,35	0,40	0,35	0,25	0,20	0,15
Hotel	0,55	0,50	0,45	0,45	0,35	0,35	0,30	0,25
Shop	0,50	0,45	0,40	0,40	0,30	0,25	0,25	0,25
Workshop	0,70	0,65	0,60	0,55	0,55	0,50	0,40	0,35

(Source: www.enova.no)

In Norway the Norwegian Meteorological Institute monitor, calculate and publish meteorological data from about 340 monitoring stations in Norway. Information about daily temperatures and normal temperatures for a specific area can be found on their web site www.met.no. Table 10-3 shows examples of metered temperatures and the associated normal temperature for some days in November 2012 at a measure station in Steinkjer, Norway. The 3-day average temperature can easily be calculated from these daily average values.

The temperature dependency has some time delay - it takes time for the cold to creep inside the houses. It is therefore considered more correct to use the 3-day average as a basis for the adjustment rather than the daily average. When peak load for one specific year is adjusted and referred to peak load for the dimensioning year, the dimensioning outdoor temperature (winter design outdoor temperature) is used as a reference. This design temperature is in Norway defined as the lowest 3-day average temperature during a period (usually the last 30 years) [14].

Table 10-3 Example of metered and normal daily temperatures (in °C) at station EGGE in Steinkjer, Norway

Date	Average temperature	Minimum temperature	Maximum temperature	Normal average temperature
01.11.2012	5,2	1,1	9,4	2,0
02.11.2012	6,8	5,8	8,1	1,8
03.11.2012	4,1	1,3	8,5	1,6
04.11.2012	-0,1	-2,8	4,2	1,4
05.11.2012	-0,3	-2,7	1,7	1,2
06.11.2012	1,1	-0,8	3,1	1,0
07.11.2012	1,7	-0,7	4	0,8
08.11.2012	-0,6	-2,4	1,5	0,6
09.11.2012	-1,2	-5	0,9	0,4
10.11.2012	2,4	0,3	5,3	0,2
11.11.2012	2,5	-1	5,6	0,0
12.11.2012	2,7	-0,2	4,9	-0,2
13.11.2012	0,4	-2,2	1,2	-0,3
14.11.2012	5,5	1,1	7,8	-0,5

(Source: www.met.no)

10.1.2 Load variation curves and hourly expected maximum load

Load variation curves illustrate how expected loads vary in time with reference to maximum load (i.e. highest metered value of the data basis). The load variation curves can be calculated from temperature corrected time series with metered energy consumption on an hourly basis. Better resolution than one hour can be used in principle, but it will probably not provide a better and more reliable result. A finer discretization can capture some extreme conditions that would be smoothed with a rough representation, but these situations are sporadic and the risk of disregarding them in the planning decision can be acceptable (see Chapter 9.2.1, last paragraph).

Loads and generation vary and have a somewhat stochastic character, and:

- Normally, it will be statistically impossible to prove that the load is different at e.g. 12:00 and 15 minutes later at 12:15 in a day in January. If however, loads are controlled to e.g. start and stop at certain hours and e.g. run for short periods less than one hour, a better resolution could make sense.
- A finer discretization than one hour would result in a higher and more accurate value of the peak load. 15 minutes average value will be higher than 60 minutes average.

Consumers act individually, and consumption varies during the day, the week and the year. The consumption is not the same on Mondays and Sundays, and the consumption is not the same on a Monday in January and a Monday in July. Calculation of load variation curves can be done in several ways:

- The method assumed to be the best and most accurate is to calculate one daily load variation curve for every day (seven) for each month (twelve). This means that 7 x 12 = 84 different daily load variation curves are calculated for each load individually. This however, requires data from many years in order to produce a useful and good result. If data for e.g. three years are available, then each daily variation curve (e.g. Mondays in January) will only be based on data for about 13 days [15]. This is not enough to make a statistically reliable result.

[15] 3 years x 365 days / 12 months / 7 days = 13

- A second alternative can be to calculate daily load variation curves for workdays (Monday – Friday) and weekend/holidays (Saturday – Sunday and holidays) for each month. This means that 2 x 12 =24 different daily load variation curves are calculated for each load individually. Three years of data will in this case mean that each daily load variation curve for workdays and weekend/holidays in January will be based on about 65 and 26 days respectively [16].

- A third alternative can be to combine one yearly load variation curve and two daily load variation curves (like described in the second alternative). In this alternative, it is assumed that the daily variation is the same in every month. This means that three load variation curves (yearly variation curve and daily variation curves for workdays and weekends/holidays respectively) are calculated for each load individually. Three years of data will in this case mean that each yearly variation curve is based on data from every day in the time series, i.e. about 1095 days and each daily load variation curve for workdays and weekends/holidays will be based on about 782 and 312 days respectively.

Examples of yearly and daily variation curves are shown in Figure 10-2 and Figure 10-3. These curves are calculated according to the third alternative, from a real three year time series with consumption in kWh/h-values from a specific school supplied by the distribution system utility NTE Nett in Norway. A flow-chart describing how daily variation curves can be calculated is shown in Figure 10-11, page 101.

Expected maximum load for specific hour can be calculated by multiplying the maximum load (peak load) with the corresponding factor (-s) from the variation curve(-s). If yearly and daily variation curves are combined, the corresponding factors from both curves must be multiplied with the peak load. If this is done for every hour in a year, the result can be as shown in Figure 10-4 for one week and as Figure 10-5 for a year. The peak load for this customer is 136 kWh/h.

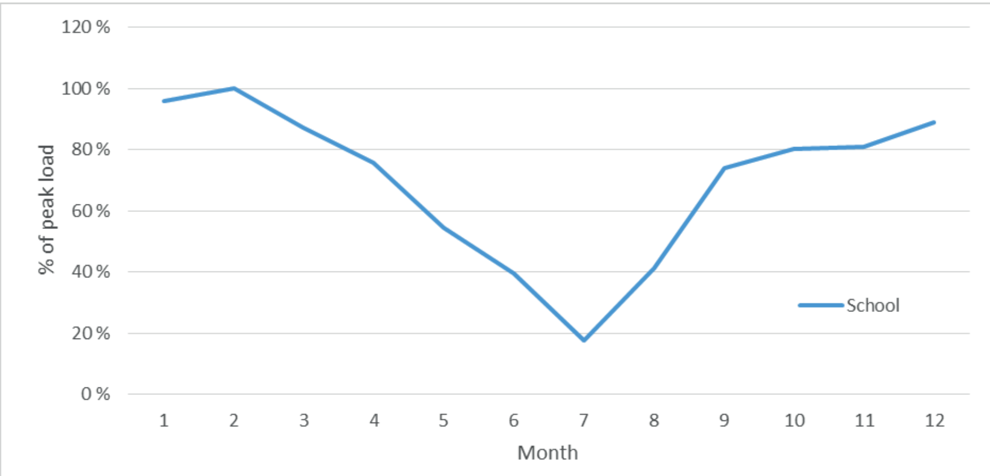


Figure 10-2 Example of yearly variation curve calculated for one specific school consumer (NTE Nett)

[16] For workdays: 3 yeas x 365 days /12 months x 5 days / 7 days = 65 days. For weekends/holidays: 65 days x 2/5 days = 26 days

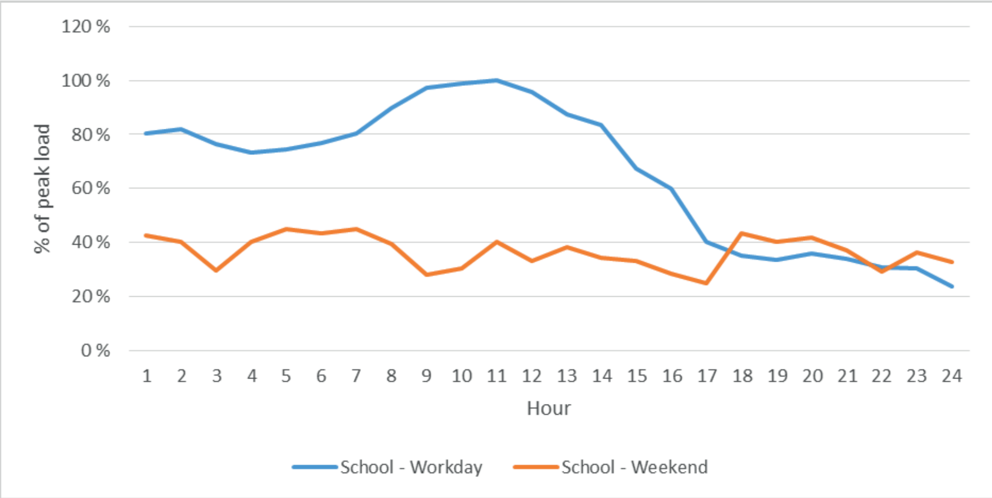


Figure 10-3 Example of daily variation curves calculated for one specific school consumer (NTE Nett)

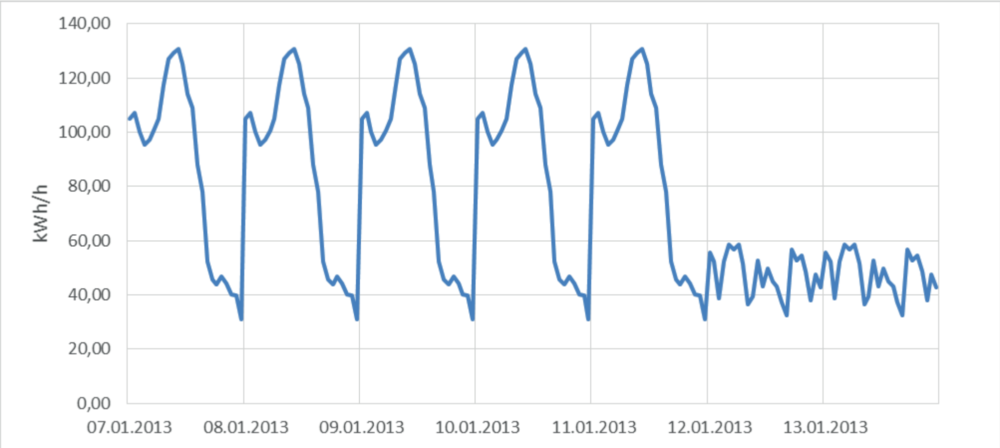


Figure 10-4 Expected variation curve calculated for one specific school consumer, one week in January

The variation curves in Figure 10-2Figure 10-3Figure 10-4Figure 10-5

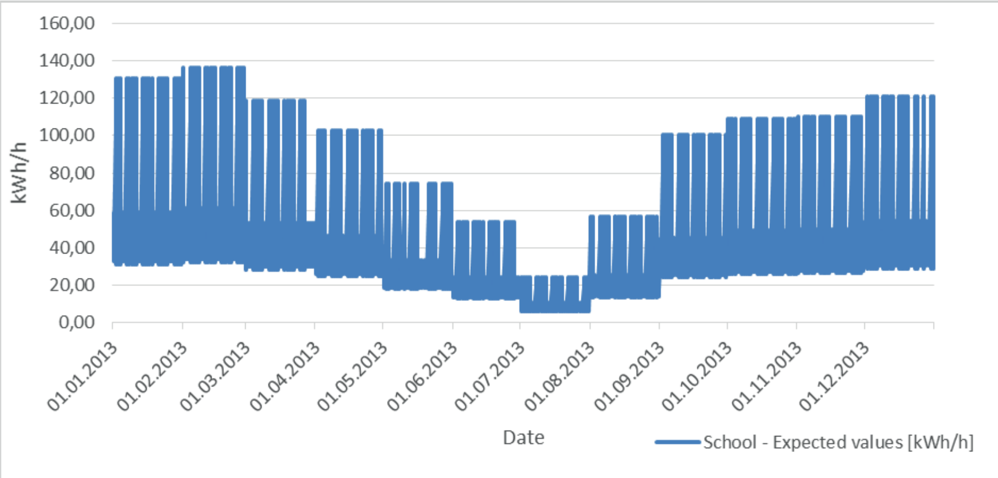


Figure 10-5 Expected variation curve calculated for one specific school consumer, one year

10.1.3 Distribution function describing the stochastic load variation

To describe the stochastic variation around the expected value, a stochastic variable can be added to the expected value. The stochastic variable can be expressed by the statistical distribution function that best describes the hourly deviation between metered and expected value for a time series of several years with kWh/h values (or even 15 min values).

The deviation can be calculated as:

$$Deviation = \frac{Measured\ value - Expected\ maximum\ load}{Expected\ maximum\ load} \cdot 100\% \qquad (10\text{-}2)$$

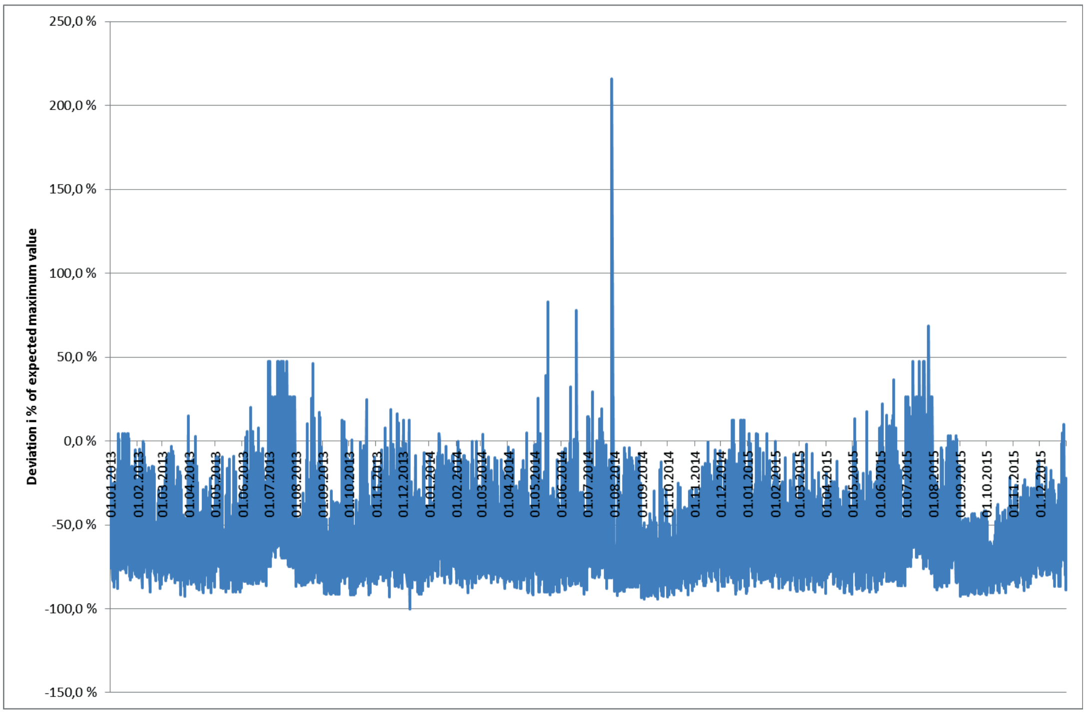


Figure 10-6 Relative deviation between calculated hourly expected maximum values and real metered values. One specific school consumer during 2013-2015.

By analyzing the relative deviation like the one in Figure 10-6, it is possible to find the probability density function that best describes this stochastic variation in the load. The probability density function is a probability distribution function with a set of parameters. Fitting distribution functions to data can be done by using computer tools like the Excel ad-in ModelRisk [17] which is used in this work.

In the Distribution Fit window in ModelRisk (Figure 10-7), you can fit distributions to a set of data in the spreadsheet. Different distribution functions and their parameters are estimated using maximum likelihood estimation (MLE). The different fitted distributions can be ranked according to the SIC (Schwarz), AIC (Akaike) and HQIC (Hannan-Quinn) information criteria. The distribution with the highest values for the chosen criteria (e.g. -SIC, -AIC or -HQIC) [18] fits the data best. More information about the ranking can be found in the ModelRisk Help-file available at http://www.vosesoftware.com/products/modelrisk/.

Figure 10-7 shows the result from a distribution fit for the relative deviation in Figure 10-6. In this case the Burr distribution with a unique set of parameters fits the data best. The blue bars in the figure is the distribution of the metered values and the red curve is the fitted Burr distribution function.

[17] www.vosesoftware.com

[18] To avoid confusion the *negatives* of these criteria are displayed in the list (ModelRisk).

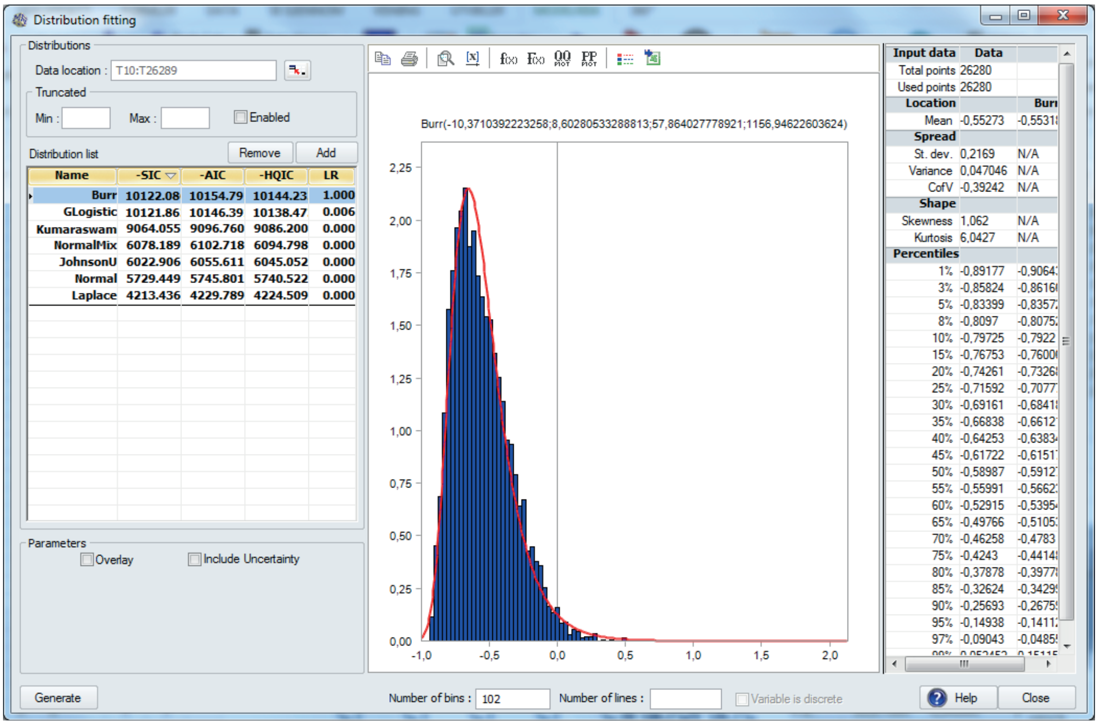


Figure 10-7 Distribution fit – for a specific school consumer – using ModelRisk

The equation for the Burr probability density function is:

$$f(x) = \frac{cd}{bz^{c+1}\,(1+Z^{-c})^{d-1}} \quad where\ \ z = \left(\frac{x-a}{b}\right) \qquad (10\text{-}3)$$

For the deviation in Figure 10-6, the Burr parameters are:

a = -10,3710392223258
b = 8,60280533288813
c = 57,864027778921
d = 1156,94622603624

Each load will have its own unique probability density function, with a distribution function and a unique set of parameters.

10.1.4 Probabilistic load model

The final probabilistic load model is the combination of the expected maximum load and the probability density function describing the stochastic variation in the load, i.e. the relative deviation between metered values and the calculated expected maximum values. By adding together the expected maximum values in Figure 10-5 and the probability density function in Figure 10-7, the result is a probabilistic load model shown in Figure 10-8. The real metered (and temperature corrected) time series, which is used as a basis for this calculation, is shown in Figure 10-9 for comparison.

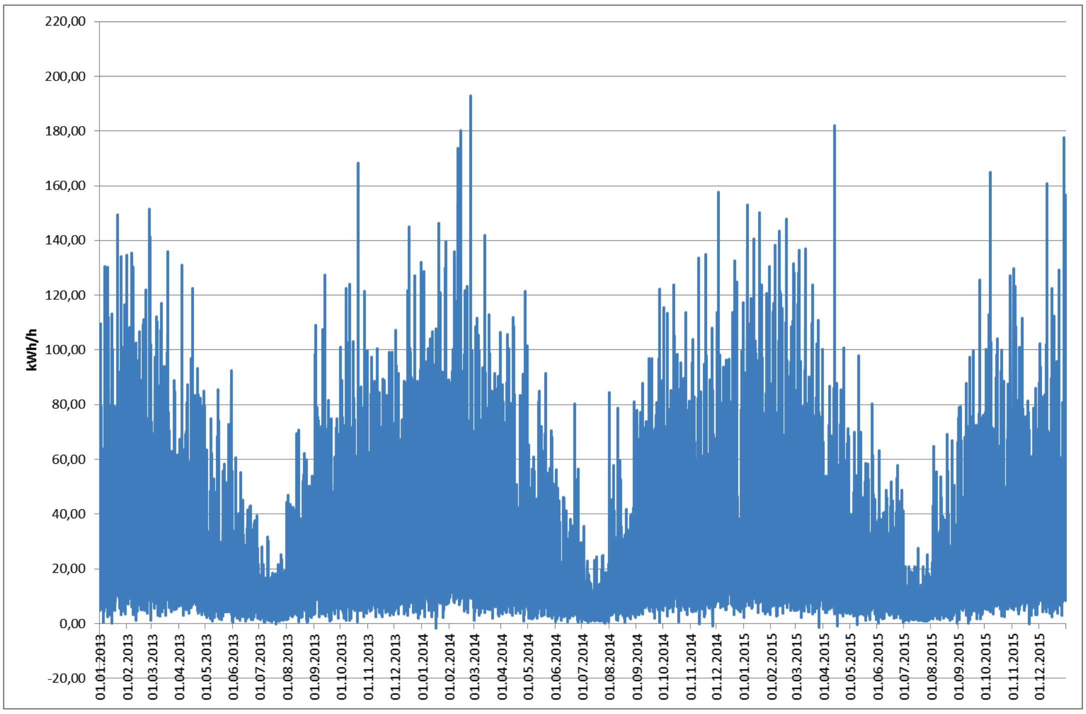


Figure 10-8 Calculated load using a probabilistic load model (one specific school consumer)

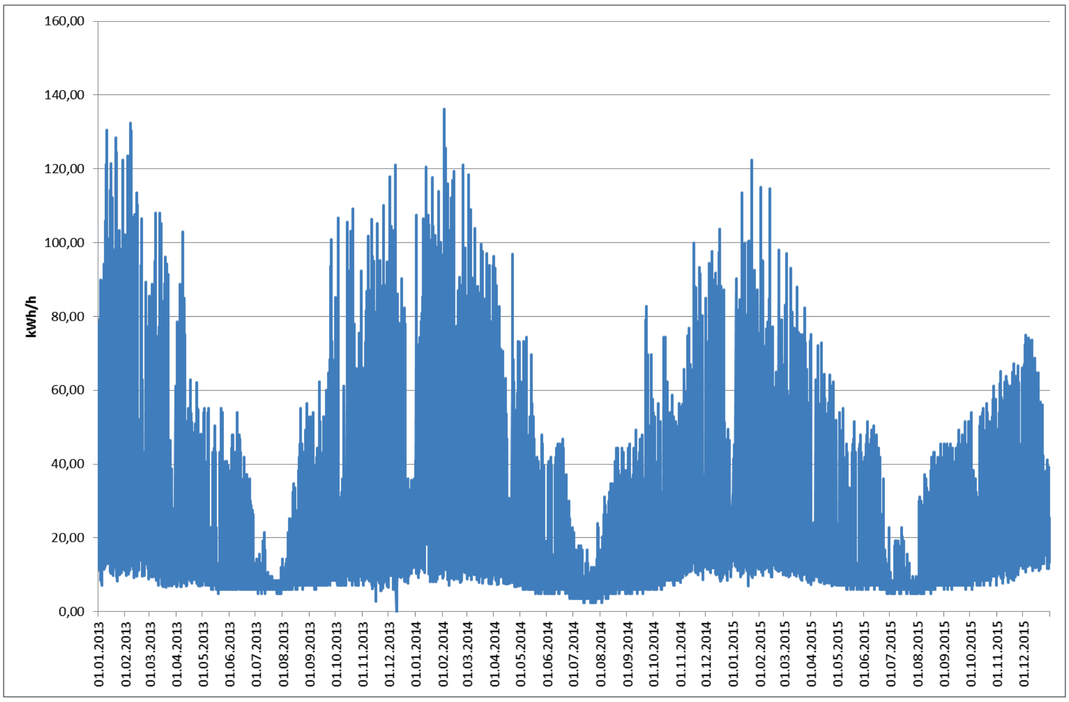


Figure 10-9 Metered kWh/h (temperature corrected) for a specific school consumer 2013-2015 used as a basis for the analyzes.

10.2 Testing of some alternatives of new load modelling methods

Chapter 10.1 describes the principles of a new method of load modelling with the use of data from smart meters. The method can be implemented in different ways regarding the reference peak load and number of load variation curves. Some alternatives have been compared in order to find the best method.

10.2.1 Modelling alternatives

Four different load modelling alternatives A-D (Table 10-4) were investigated and tested up against real metered data. The best alternative is then tested up against today's method for load modelling as described in Chapter 4 . The tested models are all based on the same idea about using load variation curves in combination with a distribution function describing the stochastic nature of the load, as described in chapter 10.1. The difference between the alternatives is the reference value and the number of load variation curves used. Table 10-4 gives a brief overview of the alternatives investigated.

Table 10-4 Investigated alternatives for load modelling

#	Reference	Load variation curves	Number of load variation curves used
A	Average load	Yearly variation (per month) Daily variations (per hour) • Normal working day (Monday-Friday) • Weekend and holiday	3
B	Maximum load	Yearly variation (per month) Daily variations (per hour) • Normal working day (Monday-Friday) • Weekend and holiday	3

C	Average load	Daily variations (per hour)
		• Two variations per month
		  ○ Normal working day (Monday-Friday)
		  ○ Weekend and holiday
			24

D	Maximum load	Daily variations (per hour)
		• Two variations per month
		  ○ Normal working day (Monday-Friday)
		  ○ Weekend and holiday
			24

Explanations:
Average load is used as a reference value in alternative A and C. For each time series (i) with metered data the average value of all (N) metered values ($W_{i,n}$) in the time series is calculated. Load variation curves are expressed as percent-values of this average load.

$$Average\ \ load = \overline{W_i} = \frac{1}{N} \cdot \sum_{n=1}^{N} W_{i,n} \qquad [\frac{kWh}{h}] \qquad (10\text{-}4)$$

Maximum load (peak load) is used as a reference value in alternative B and D. Maximum load is the absolute highest metered value in the time series. If the 99 or 98 percentile value is used instead of the 100 percentile, the most extreme (faulty) values could be avoided. The 99 percentile is more difficult to find when several criteria are used to select the values. That is why the 100 percentile is used in this investigation.

$$Maximum\ load = \widehat{W_i} = \max_{1 \le n \le N} W_{i,n} \qquad [\frac{kWh}{h}] \qquad (10\text{-}5)$$

Yearly variation describes how the expected average load (in alternative A and C) or expected maximum load (in alternative B and D) varies monthly through the year. The yearly load variation curve for series "*i*" is found by calculating the ratio in percent between monthly average load (or monthly maximum load) and the reference value (average load or maximum load). Figure 10-2 shows an example of a yearly variation curve for a specific consumer. Figure 10-10 illustrates how a yearly load variation curve for load *"i"* can be calculated from hourly values ($W_{i,n}$) and referred to average load.

Daily variation describes how the expected average load (in alternative A and C) or expected maximum load (in alternative B and D) varies hourly through the day. In alternative A and B only two daily load variation curves are calculated – workday and weekend/holiday. In these alternatives, it is assumed that the daily variation is the same in every month. In alternative C and D two different variation curves are calculated for each month. These alternatives takes into consideration that the daily variation might vary through the year. The consumption in winter does not necessarily follow the same pattern as the consumption in summer. Figure 10-3 shows an example of a daily variation curve for a specific consumer. Figure 10-11 illustrates how a daily load variation curve for load *"i"* can be calculated from hourly values ($W_{i,n}$) and referred to maximum load.

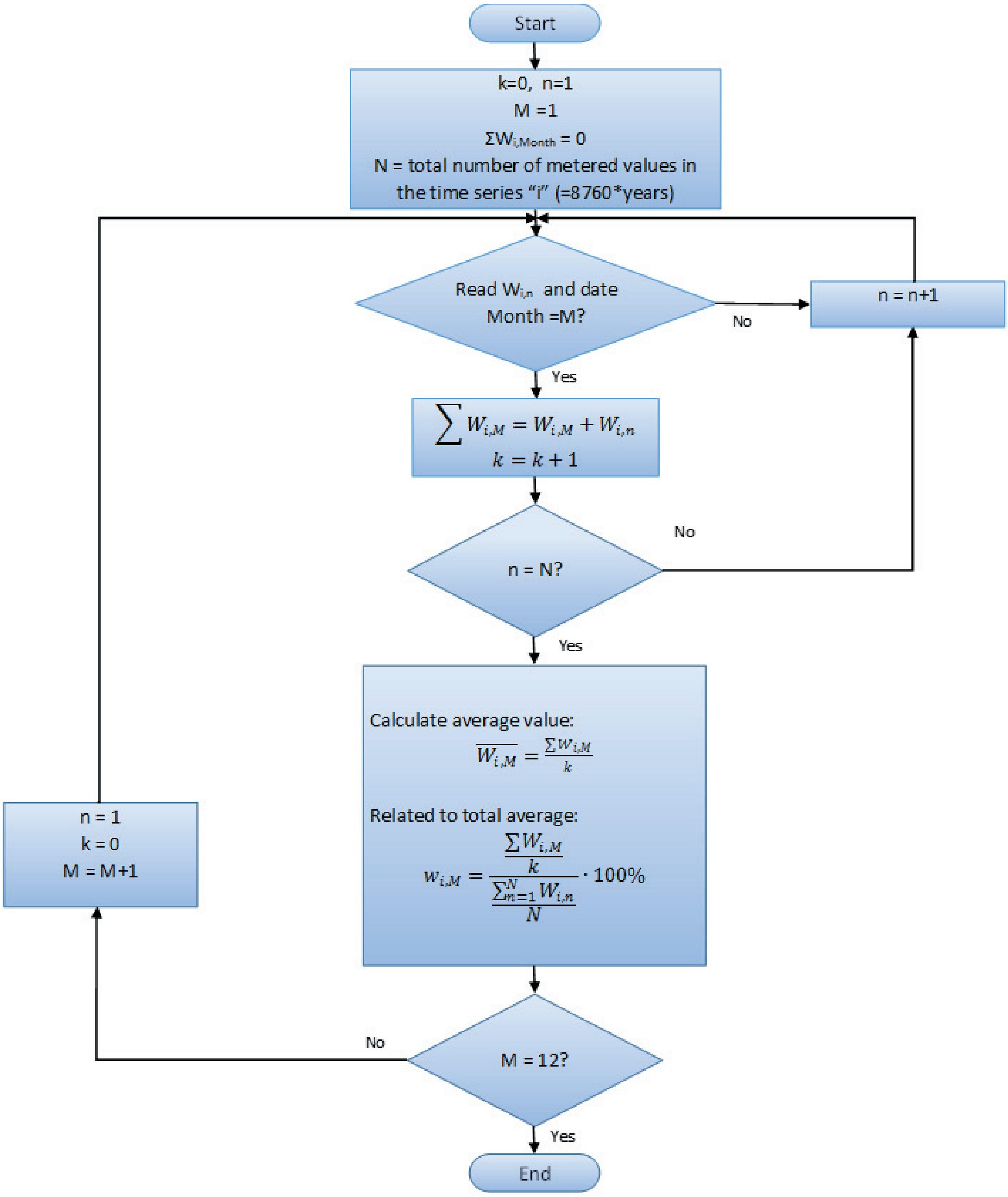


Figure 10-10 Flow-chart - Calculating yearly load variation curve referred to average load for load "i"

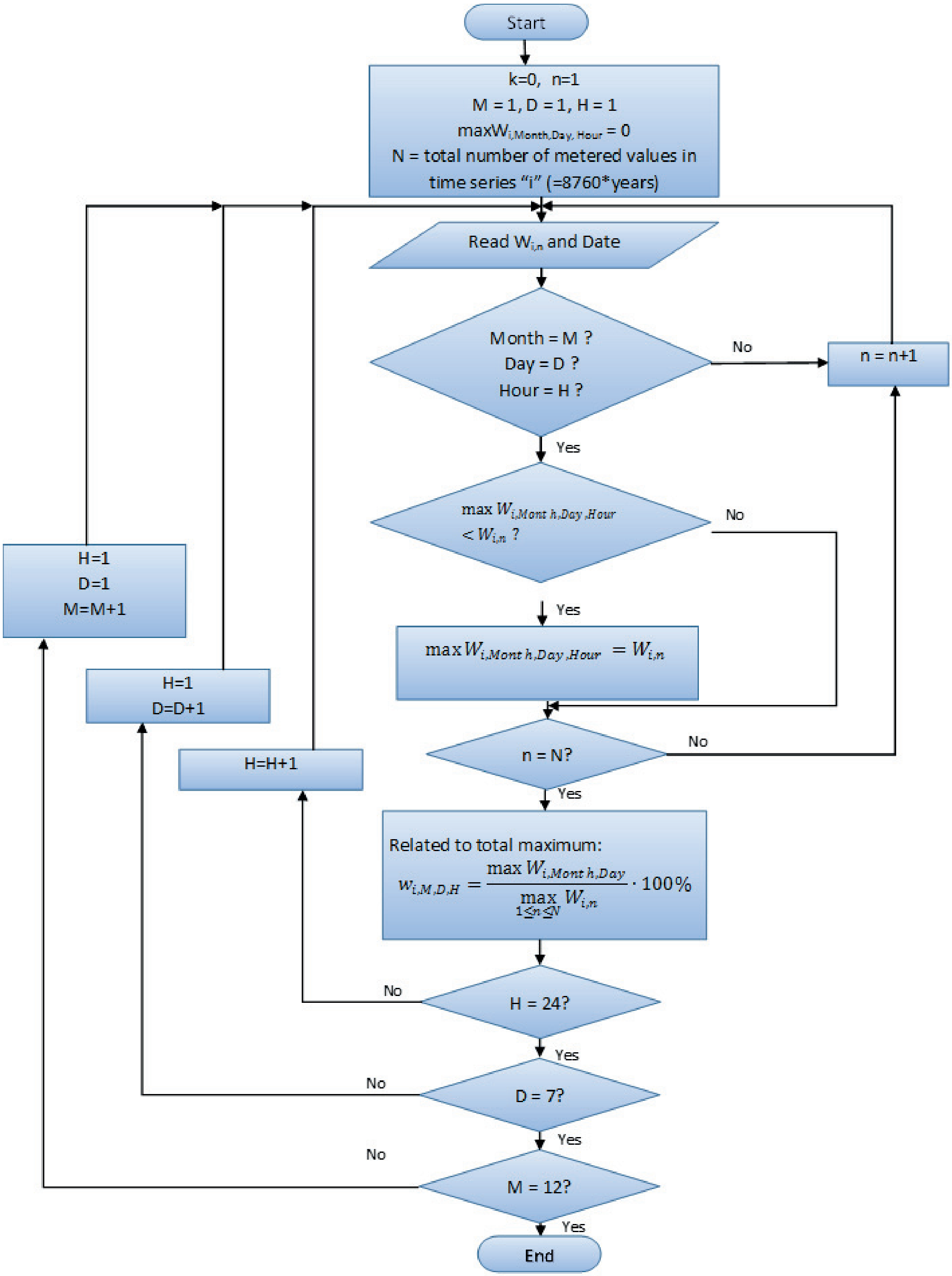


Figure 10-11 Flow-chart - Calculating yearly daily variation curve referred to maximum load for load "i"

10.2.2 Evaluation of the alternatives

Time series – the same seven loads (consumers) mentioned later in *Chapter 11 Case study* – with hourly metered energy consumption (kWh/h) over a period of three years (2013-01-01 – 2015-12-31), are used to test the alternatives in Table 10-4 and decide which is the best, i.e. which alternative fits the real metered data best.

For each load, four alternative sets of load variation curves are calculated according to the alternatives in Table 10-4. These variation curves are then used to calculate an hourly expected load. The deviation between this expected load and the corresponding metered load is then used to find a stochastic distribution function that best fits the deviation. The load model consists of the sum of the hourly expected load described by the load variation curves and a stochastic distribution function (as described in Chapter 10.1).

The relative deviation between the stochastic load model and the metered load is then calculated for **every hour** in the period:

$$Rel.deviation = \frac{Calculated\ load\ according\ to\ the\ stochastic\ model - Measured\ and\ temp.corrected\ load}{Calculated\ average\ expected\ load} \qquad (10\text{-}6)$$

For each alternative the average value, maximum value, minimum value and the standard deviation of the relative deviation are found for each of the seven loads mentioned in *Chapter 11 Case study*. The average values for the seven loads are also calculated. The results from alternative A to D are presented in Table 10-5 to Table 10-8 respectively.

Table 10-5 Relative deviation - Alternative A

Alt. A	Farm	Grocery store	House #1	House #2	House #3	School	Workshop	Average
Average value	-0,10	0,00	-0,01	0,00	0,01	0,00	-0,01	-0,02
Maximum value	20,41	1,08	4,25	3,41	3,10	7,46	4,83	6,36
Minimum value	-28,70	-1,18	-3,15	-3,25	-3,58	-4,98	-3,43	-6,90
Standard deviation	1,67	0,24	0,58	0,55	0,61	0,59	0,43	0,67

Table 10-6 Relative deviation - Alternative B

Alt. B	Farm	Grocery store	House #1	House #2	House #3	School	Workshop	Average
Average value	0,00	0,00	0,00	0,00	0,01	0,00	0,01	0,00
Maximum value	1,08	0,88	1,37	2,03	1,59	2,60	2,09	1,66
Minimum value	-1,03	-0,74	-1,04	-1,12	-1,38	-2,85	-1,19	-1,34
Standard deviation	0,24	0,20	0,32	0,30	0,31	0,31	0,36	0,29

Table 10-7 Relative deviation - Alternative C

Alt. C	Farm	Grocery store	House #1	House #2	House #3	School	Workshop	Average
Average value	-0,10	0,00	0,00	0,00	0,00	0,00	-0,01	-0,02
Maximum value	10,81	1,41	3,33	2,99	2,95	5,39	3,62	4,36
Minimum value	-35,62	-1,15	-3,73	-4,62	-3,50	-5,66	-3,06	-8,19
Standard deviation	1,54	0,23	0,57	0,53	0,59	0,51	0,40	0,62

Table 10-8 Relative deviation - Alternative D

Alt. D	Farm	Grocery store	House #1	House #2	House #3	School	Workshop	Average
Average value	0,01	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Maximum value	1,03	0,73	1,62	1,56	1,75	1,68	0,88	1,32
Minimum value	-1,00	-0,72	-1,00	-0,93	-0,99	-1,00	-0,89	-0,93
Standard deviation	0,37	0,20	0,33	0,30	0,31	0,32	0,32	0,31

When comparing the average values (column to the right) for the seven different loads in the four alternatives, it appears that the relative deviation in alternative A and C is larger than in alternative B and D. It is larger both in extreme values and in standard deviation. **This means that load models made according to alternative B and D give better results than the two other alternatives**.

The difference between alternative B and D in this case is negligibly small. This means that the load model using different daily load variation curves for each month does not give a significantly better result than the load model using the same daily variation curves for the whole year. Later in this thesis, in Chapter 11.2.2 (page 114) load models are made according to alternative B because this alternative fits the metered data best (together with alternative D), has the same number of load variation curves as today's model and is a simpler method than alternative D.

10.3 Generation modelling

Generation connected to the distribution grid, can be divided in two groups:

- Generation and consumption are connected to the same meter. This can for example be a prosumer – a consumer that produces electricity, often by rooftop solar panels, and sells surplus energy back to the grid. In this case, the generation does not need to be modelled separately. One model can include both generation and consumption.
- When generation is metered separately with an own meter, the generation must naturally be modelled separately.

Various types of power plants have different generation profiles, and generation should therefore be modelled individually just like ordinary consumers. Generation from renewable energy sources like wind and sun, do also vary stochastically and need to be modelled by a stochastic distribution function.

Generation where hourly metered generation values exist for some years, can be modelled the same way as loads, described in Chapter 10.1. Metered data can be used to define generation variation curves and find the distribution function that fits the stochastic variation in the generation best. There is in principle no difference between load and generation modelling according this method.

10.4 Load and generation modelling without data from smart meters

Metered and probabilistic data are in some cases, unknown. This can e.g. be when:

- New power plants from e.g. renewables like wind and solar are connected to the grid
- New consumers/loads like e.g. new businesses and buildings are connected to the grid
- An existing consumer installs generation and becomes a prosumer

A new load/generation can be modelled similar to a standard or known equivalent load/generation model if any exist. The standard/known equivalent load/generation variation curves and distribution function for stochastic variation can be used for the new load/generation for a few years until sufficient amount of metered data for individual modelling are collected.

If a corresponding standard model or equivalent load/generation does not exist (is unknown), then the planner can estimate a load/generation model based on experience and use this model for a time (few years) until sufficient metered data are known. One example of an estimated model representing the generation from a 50 kW rooftop solar panel is shown in Chapter 11.4.2.

10.5 Modelling of Active Distribution System solutions

Assessment of ADS solutions like e.g. demand response, demand side management and generation curtailment, is included in the probabilistic planning methodology shown in Figure 9-2. Such ADS solutions must therefore be included in the network calculations, and this can be done by e.g. introducing conditional expressions into the load and generation models or into the algorithms for network calculations. Two examples will illustrate how this can be done.

Example 1 – Load limit for a consumer:

If a specific load or generation is limited to a defined value by the consumer or by the utility, the corresponding probabilistic model used in network calculations must be limited to the same value. This can be done by modifying the load or generation model by using If-Then-Else statements:

IF *a limit is defined*

THEN IF *load is larger than the limit*

THEN *load is set equal to the limit*

ELSE *load is unchanged*

ELSE *load is unchanged*

Similar statements can be used for generation and for other restrictions. If several restrictions are set for the same load/generation, several statements must be nested together in order to give a correct expression of the limitations.

Example 2 – Load limits for cables:
Active management of demand and generation can e.g. be used in order to prevent overloading of cables. This can be implemented in various ways in the network calculation systems in the market. If-Then-Else statements can be used to model these limitations as well:

- The total load (consumption and generation) supplied by the cable, must be lower than the load that results in 100 % load on the cable.
- If the total load is higher than the limit, then one by one of the predetermined consumers/generators, have their load/generation reduced according to predefined rules, until the total load is equal to the limit.
- If reduction of the first load is not enough to reduce the total load below the limit, then the next load is reduced. If this is not enough, then the third load is reduced and so on.

For the first load (load1):

IF *total load is larger than the limit*

THEN IF *the difference between total load and the limit is larger than the difference between load1 and the lower limit for load1*

THEN *load1 is set to the lower limit for load1*

ELSE *load1 is reduced with the difference between the total load and the limit*

ELSE *load 1 is unchanged*

For the second load (load2):

IF *total load is larger than the limit*

THEN IF *the difference between total load and the limit is larger than the difference between load1 and the lower limit for load1*

THEN IF *the difference between total load and the limit minus the difference between load1 and the lower limit for load 1 is larger than the difference between load2 and the lower limit for load2*

THEN *load2 is set to the lower limit for load2*

ELSE *load2 is reduced with the difference between the total load and the limit minus the difference between load1 and the lower limit for load1.*

ELSE *load 2 is unchanged*

ELSE *load 2 is unchanged*

It is possible to continue like this with similar statements in order to give a correct expression of the limitations and the demand management scheme. ADS solutions like the one in these two examples are used in the case study in Chapter 11.3.

PART IV – Testing and verification

11 Case study

A case study is used to demonstrate the methods described in Part III and IV in this report. The demo will compare the present old method with the suggested new method for load modelling. The case study includes only regular load flow calculations. The calculations are done in Microsoft Excel based on a spreadsheet created by SINTEF Energy Research, available through [14], made for a simple calculation of load flow along a low voltage radial. The spreadsheet had to be modified to fit the purpose of this study. The spreadsheet calculates originally the load flow "backward" from the outermost load point and up to the feeding substation. In addition to changing the calculation method so that the load flow is calculated "forward" from the feeding substation to the outermost load point, an Excel ad-in (ModelRisk) is used to do the load flow calculations as Monte Carlo simulations. When the loads and generation are modelled as probability density functions, the results (currents and voltages) will also be presented as probability density functions.

11.1 Case description

A simple low voltage network is used to test the models described in Part IV in this thesis. The model is illustrated in the single line diagram in Figure 11-1. The model consists of one distribution substation with one 22/0,4 kV, 315 kVA transformer, seven different loads and one generation unit, all radially connected with cables.

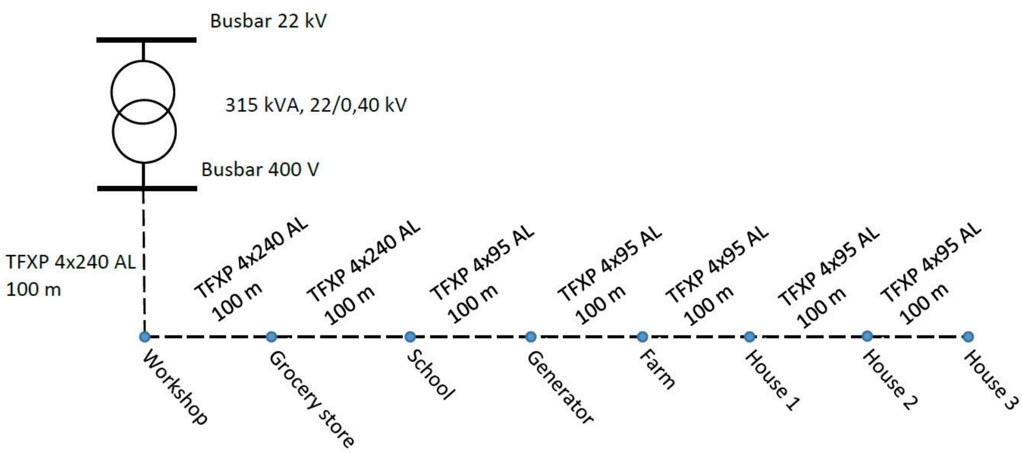


Figure 11-1 Demo case - Single line diagram

Table 11-1 Branch data

Node 1	Node 2	Type	Length [m]	R [Ω]	X [Ω]	I_{th} [A]
Busbar 22 kV	Busbar 400V	315 kVA 22/0,4 kV	-	0,005	0,025	455
Busbar 400V	Workshop	TFXP 4x240 Al	100	0,013	0,007	375
Workshop	Grocery store	TFXP 4x240 Al	100	0,013	0,007	375
Grocery store	School	TFXP 4x240 Al	100	0,013	0,007	375
School	Generator	TFXP 4x95 Al	100	0,032	0,008	220
Generator	Farm	TFXP 4x95 Al	100	0,032	0,008	220
Farm	House1	TFXP 4x95 Al	100	0,032	0,008	220
House1	House2	TFXP 4x95 Al	100	0,032	0,008	220
House2	House3	TFXP 4x95 Al	100	0,032	0,008	220

11.2 Load models

The loads in this model are presented in Table 12-2. These are real loads, and time series with metered hourly electric energy consumption for the years 2013-2015 are used as basic data for the models. The loads are modelled both deterministic as described in Chapter 4 (page 21) and probabilistic as described in Chapter 10.1 (page 87). The probabilistic model used is the Alternative model B in Table 10-4.

Table 11-2 The loads

Name	Year of construction	People living or working there	Heating system	Description
Workshop	1990	10	Heat pump and electricity	Includes office, shop, store and workshop
Grocery store	2000	5	Heat pumps and electricity	Open 6 days a week 0700 - 2300
School	2012	200	Heat pump and electricity	Primary school
Farm	1986	1	No heating	EV charging, grain dryers with large fans/motors
House #1	1790	8	Firewood, electricity	Old large farmhouse
House #2	1960	2	Firewood, heat pump, electricity	Semi-detached house
House #3	1970	5	Firewood, heat pump, electricity	Detached house

Table 11-3 The loads - Basic information about the selected time series (2013-2015)

Name	Energy consumption [kWh/year]	Maximum [kWh/h]	Average [kWh/h]	Minimum [kWh/h]
Workshop	79 980	30,43	9,04	1,96
Grocery store	593 160	115,66	66,71	21,58
School	188 070	136,23	24,41	0,00
Farm	8 200	36,73	1,01	0,00
House #1	36 540	14,68	4,63	0,00
House #2	21 060	10,21	2,56	0,00
House #3	22 950	10,66	2,59	0,00

11.2.1 Deterministic load models
Three different deterministic load models are made.

The first model is made according to the method used by NTE Nett today, described in Chapter 4 (page 21). Maximum loads in this model are calculated by dividing annual energy consumption with standard utilization time for the consumer category. Standard load variation curves for the different load categories are used. Table 11-4 summarizes the information used in this first deterministic model.

Table 11-4 Load models – Deterministic #1

Load	Annual energy consumption [kWh/h]	Utilization time [h/year]	Max load (1) [kW]	Cos (φ)	Yearly load variation curve	Daily load variation curve
Workshop	79 980	4 100	19,507	0,980	Standard	Retail trade
Grocery store	593 160	4 100	144,674	0,980	Standard	Retail trade
School	188 070	3 800	49,493	0,980	Standard	School
Farm	8 200	3 000	2,734	0,980	Standard	Farming
House 1	36 540	3 600	10,150	0,980	Standard	Household
House 2	21 060	3 600	5,850	0,980	Standard	Household
House 3	22 950	3 600	6,374	0,980	Standard	Household

(1) Max power = yearly energy consumption / Utilization time

Yearly load variation curve describes how the consumption varies monthly (in percent of maximum load) during the year. The standard yearly load variation curve is shown in Figure 11-2.

Daily load variation curve describes how the consumption varies hourly (in percent of maximum load) during the day. The standard daily load variation curves are shown in Figure 11-3.

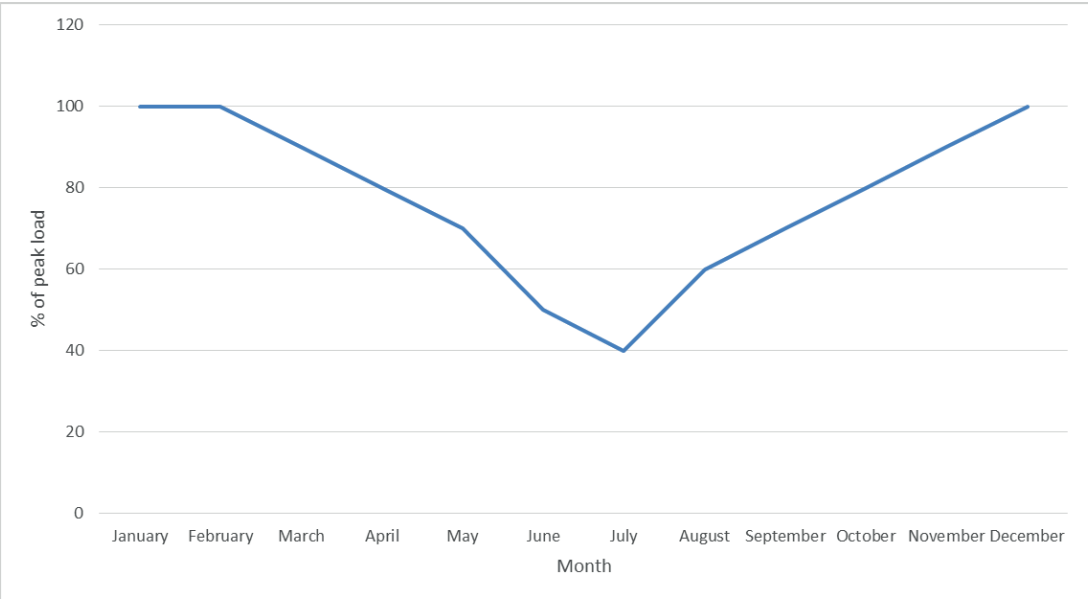


Figure 11-2 Standard yearly load variation curve used

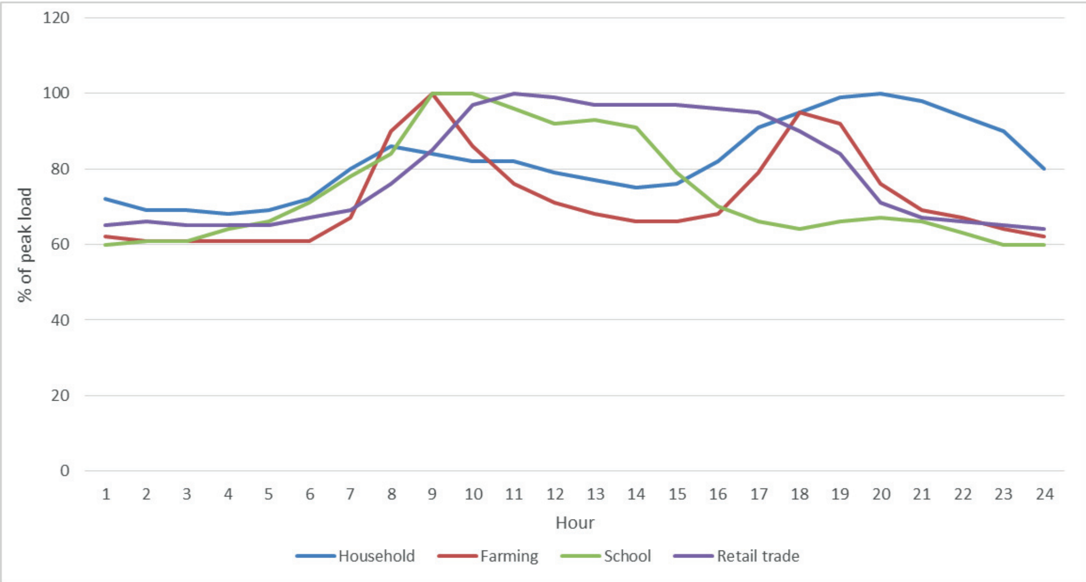


Figure 11-3 Standard daily load variation curves used

The second model is made as the first model, except that individual load variation curves are calculated, as described in Chapter 10.1.2, page 91. Table 11-5 summarizes the information used in this second deterministic model. Figure 11-4 and Figure 11-5 show the calculated individual yearly and daily load variation curves respectively.

Table 11-5 Load models – Deterministic #2

Load	Annual energy consumption [kWh/h]	Utilization time [h/year]	Max load (1) [kW]	Cos (φ)	Yearly load variation curve	Daily load variation curve
Workshop	79 980	4 100	19,51	0,980	Workshop	Workshop
Grocery store	593 160	4 100	144,67	0,980	Grocery store	Grocery store
School	188 070	3 800	49,49	0,980	School	School
Farm	8 200	3 000	2,73	0,980	Farm	Farm
House 1	36 540	3 600	10,15	0,980	House 1	House 1
House 2	21 060	3 600	5,85	0,980	House 2	House 2
House 3	22 950	3 600	6,37	0,980	House 3	House 3

(1) Max power = yearly energy consumption / Utilization time

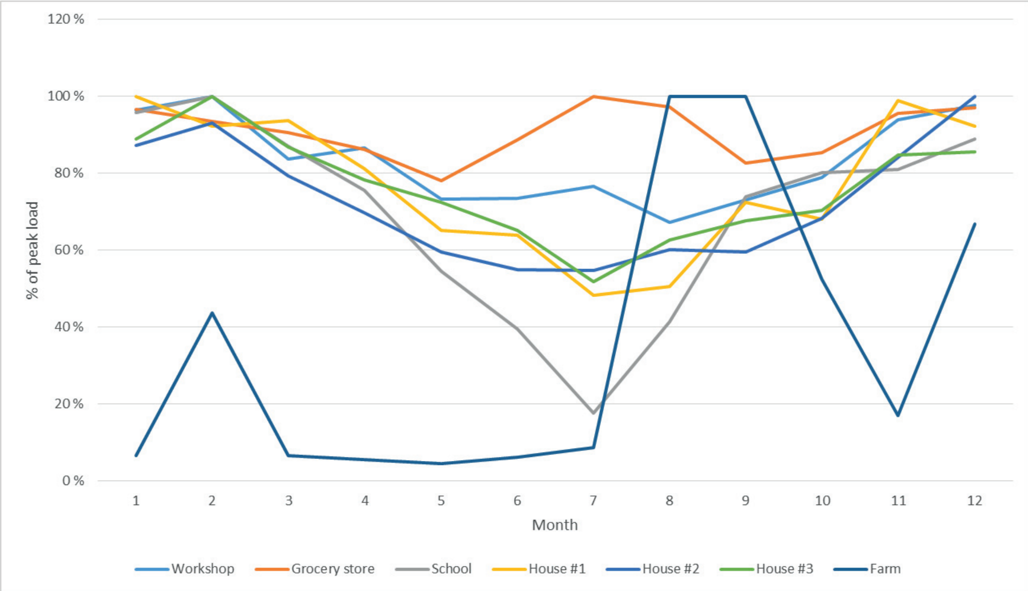


Figure 11-4 Individual yearly load variation curves

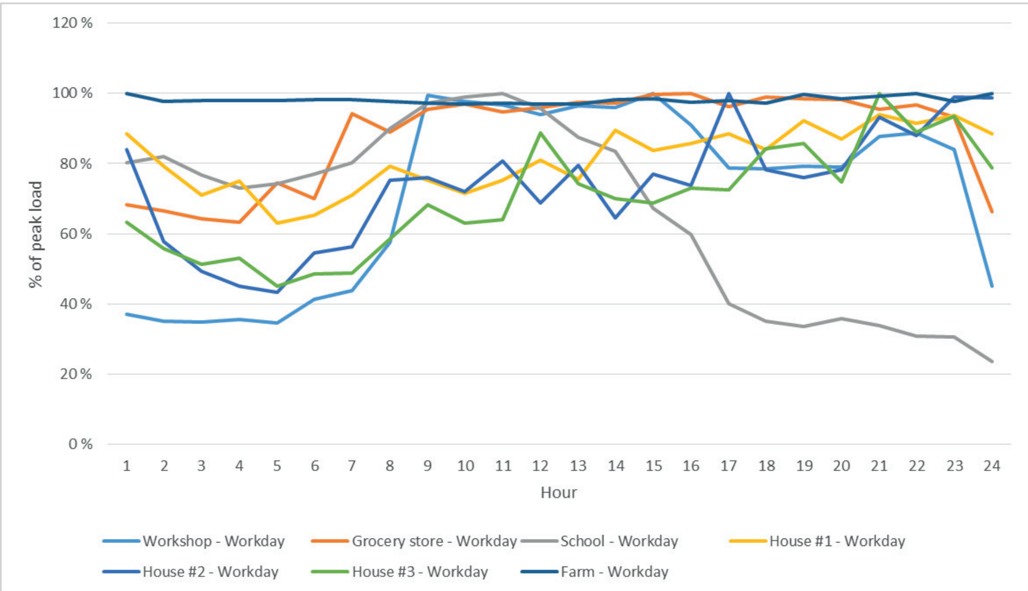


Figure 11-5 Individual daily load variation curves (ordinary workdays)

In the third model, the loads are modelled with individual load profiles as in the second model, but now the real metered peak load in each time series is used as a reference instead of a calculated peak value. Table 11-6 summarizes the information used in this third deterministic model. The individual load variation curves are the same as in Figure 11-4 and Figure 11-5.

Table 11-6 Load models – Deterministic #3

Load	Max load (1) [kW]	Cos (φ)	Yearly load variation curve	Daily load variation curve
Workshop	30,43	0,980	Workshop	Workshop
Grocery store	115,66	0,980	Grocery store	Grocery store
School	136,33	0,980	School	School
Farm	36,73	0,980	Farm	Farm
House 1	14,68	0,980	House 1	House 1
House 2	10,21	0,980	House 2	House 2
House 3	10,66	0,980	House 3	House 3

(1) Max power = highest (peak) value in the time-series (kWh/h) with metered data, temperature corrected

11.2.2 Probabilistic load models

The probabilistic load models are made according to the description given in Chapter 10.1, page 87. Maximum load and individual load variation curves are the same as described in Table 11-6, Figure 11-4 and Figure 11-5.

As mentioned in Chapter 10.1.3 page 96, each load will have its own unique probability density function, and a unique set of parameters. **The distributions used for the loads in this case are only examples and valid only for these unique loads and their time-series.**

Every load in the model except Farm, is modelled with the Burr distribution. The Burr distribution has four parameters *a*, *b*, *c* and *d*. This distribution is a right-skewed distribution bounded at *a*. *b* is the scale parameter while *c* and *d* control its shape. The Burr distribution has a flexible shape and controllable scale and location which makes it appealing to fit data. It has, for example, been found to fit tree trunk diameter data for the lumber industry. It is frequently used to model insurance claim sizes, and is sometimes considered as an alternative to a Normal distribution when data show slight positive skewness [46].

The equation for the Burr probability density function is [46]:

$$f(x) = \frac{cd}{bz^{c+1}\,(1+Z^{-c})^{d-1}} \quad where\ \ z = \left(\frac{x-a}{b}\right) \qquad (11\text{-}1)$$

The load Farm is modelled with the Johnson Bounded distribution since this fit these data best. The Johnson Bounded distribution has four parameters: *α1, α2, min* and *max*. The range is defined by the *min* and *max* parameters. Combined with its flexibility in shape (defined by the *α1* and *α2* parameter), this makes it a viable alternative to the PERT, Triangular and Uniform distributions for modelling expert opinion.

The equation for the Johnson Bounded probability density function is [46]:

$$f(x) = \frac{\alpha_2(max-min)}{(x-min)(max-x)\sqrt{2\pi}} exp\left[-\frac{1}{2}\left(\alpha_1 + \alpha_2 ln\left[\frac{(x-min)}{max-x}\right]\right)^2\right] \qquad (11\text{-}2)$$

The distribution functions describing the stochastic deviation between calculated load and metered load are described in Figure 11-6 to Figure 11-12. Along the x-axis is the relative deviation between the metered hourly value and the expected maximum value for the same hour. The value -0.40 means that the metered value is 40 % lower than the expected maximum. Along the y-axis is the probability density in % or the cumulative value (0.00 – 1.00). To the left in the figures are the parameters, and to the right are some statistics for the probability density function. The distribution function for each load is unique and shows that the loads vary individually.

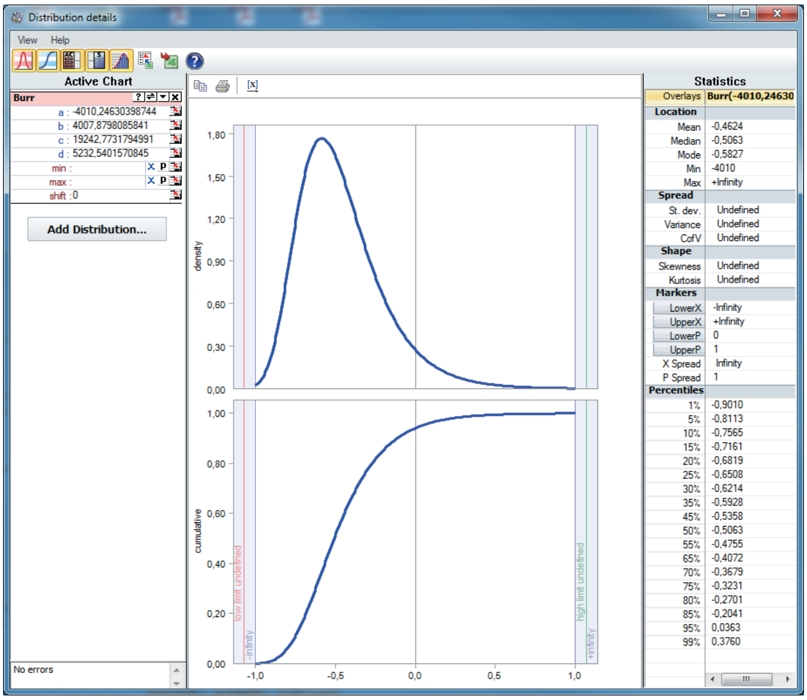


Figure 11-6 Distribution function – Workshop – on a workday (Burr)

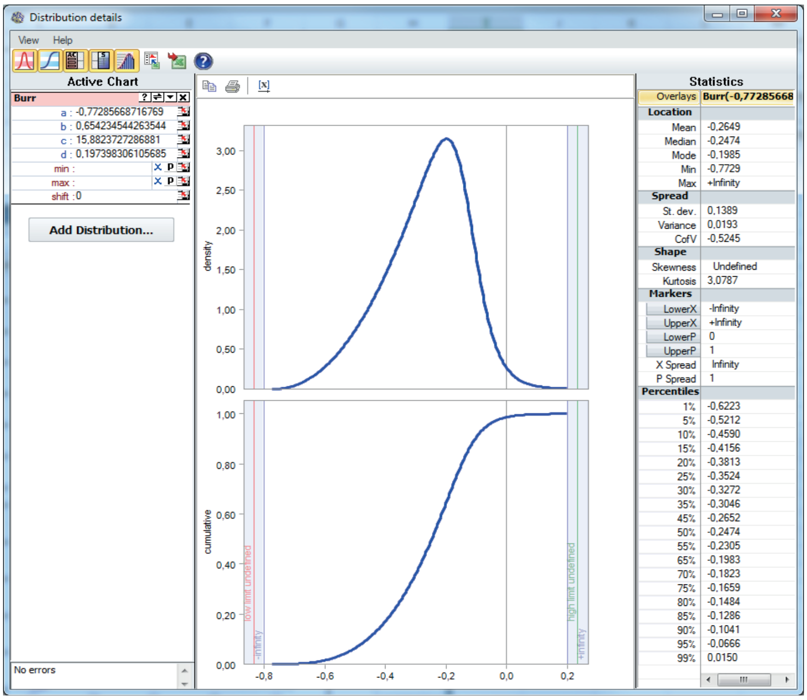


Figure 11-7 Distribution function – Grocery store – on a workday (Burr)

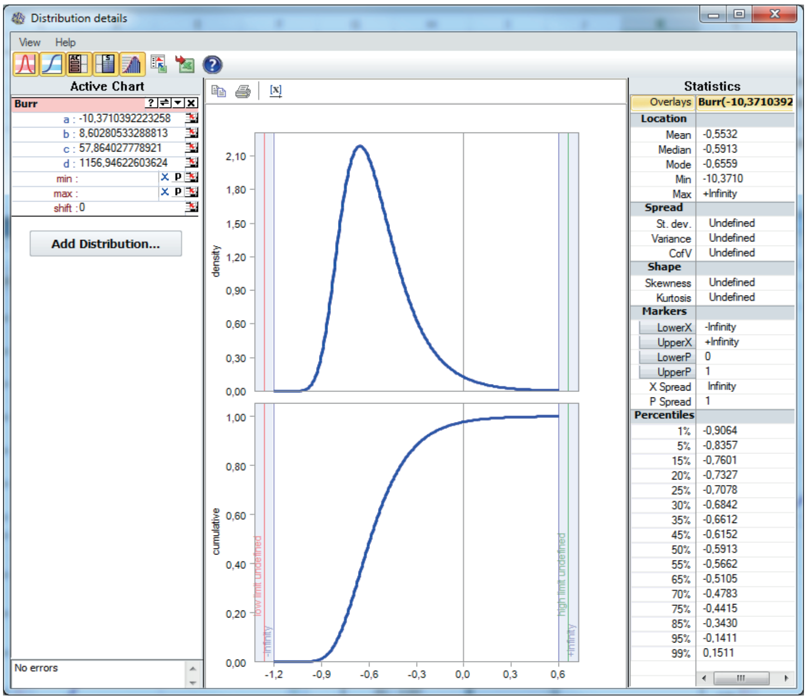


Figure 11-8 Distribution function – School – on a workday (Burr)

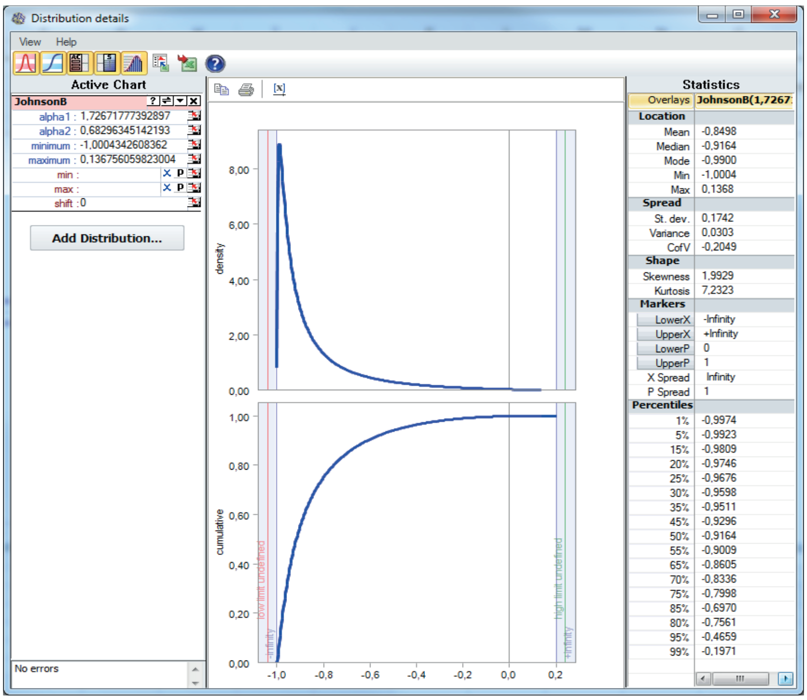


Figure 11-9 Distribution function – Farm – on a workday (Johnson Bounded)

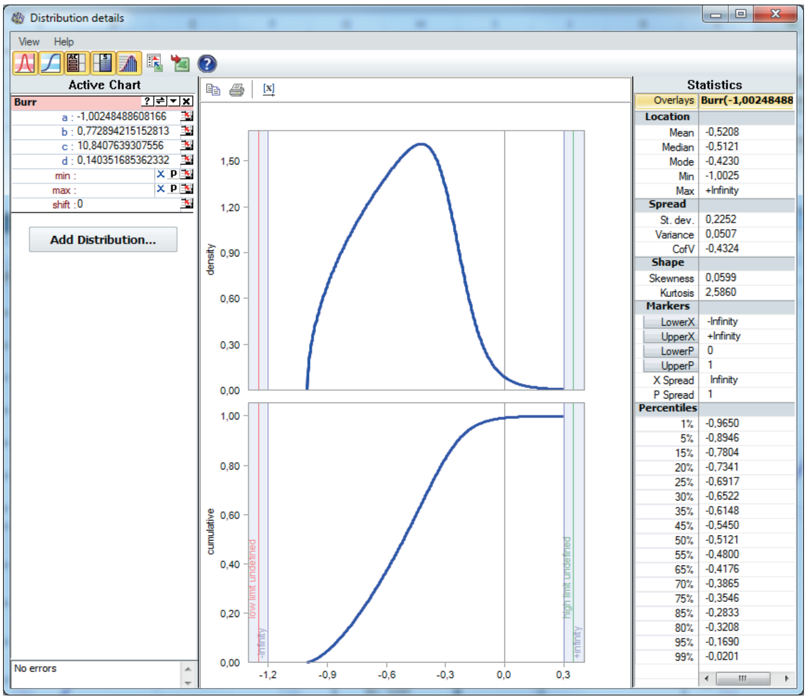


Figure 11-10 Distribution function – House 1 – on a workday (Burr)

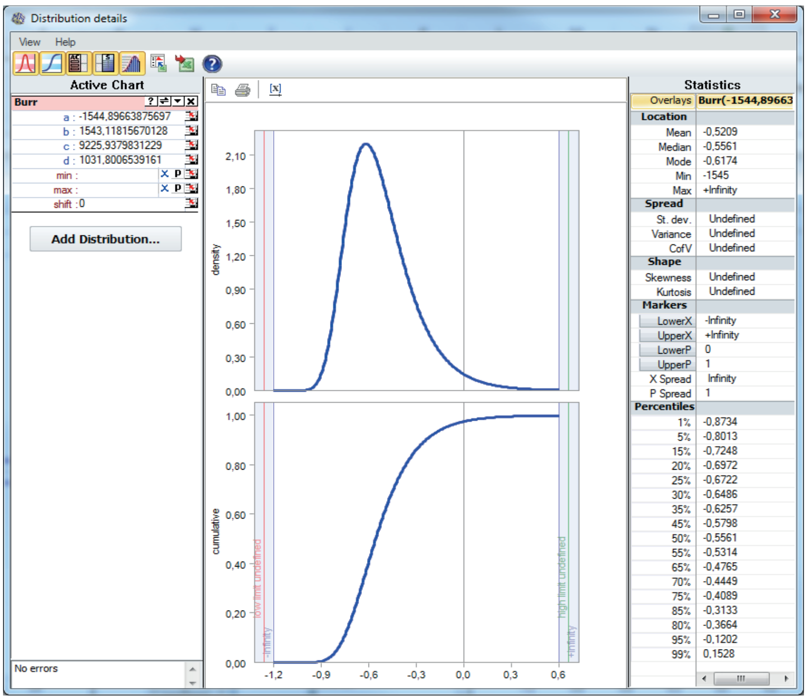


Figure 11-11 Distribution function – House 2 – on a workday (Burr)

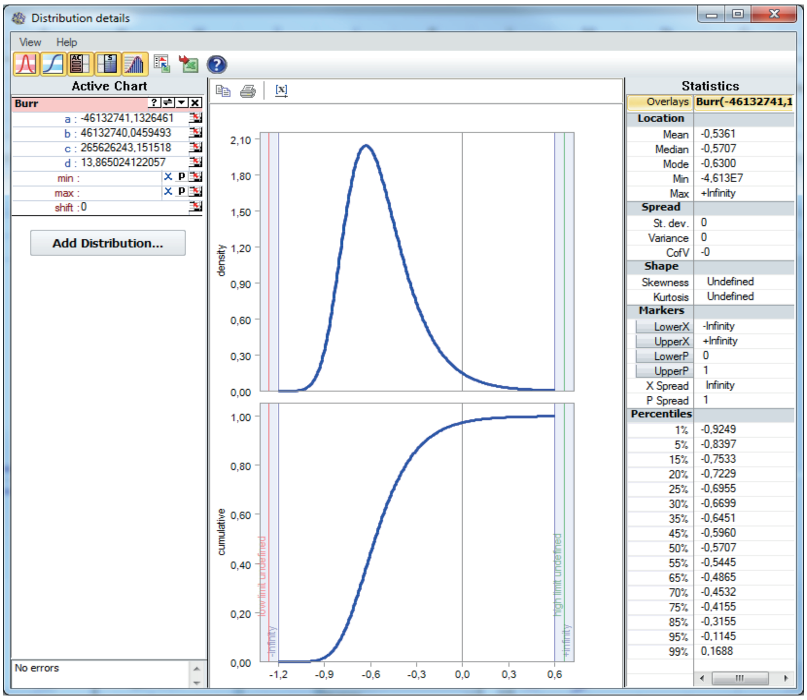


Figure 11-12 Distribution function – House 3 – on a workday (Burr)

11.3 Demand response (DR)

Some of the simulations include demand response. The purpose is to see how DR can be modelled and how it will affect the load situation in the grid. DR is one example of active management (no-network solution) in order to avoid unacceptable risk of constraint violation, as described in *Figure 9-2 Probabilistic planning methodology for electrical networks (based* on a figure found in [11]. Two types of DR are included in the case model:

- Load limits for consumers.
- Load limits for cables.

Load limits for consumers

In this demo case the load at *School* is limited to max 90 kW. If the load originally is higher, it will be limited to 90 kW. E.g. in the third deterministic model (Table 11-6) the load at school is 136 kW. When simulating this alternative the load at *School* is set to 90 kW. In the probabilistic model the load at school is checked and limited to 90 kW in every sample within the Monte Carlo simulation. This is done by using the IF function in the Excel like described below, and use the adjusted load as an input for the network calculations.

$IF\ (P_{school\ max} > 0$

$\quad IF\ (P_{school} > P_{school\ max}$

$\quad\quad P_{school}' = P_{school\ max}$

$\quad\quad P_{school}' = P_{school}\ )$

$\quad P_{school}' = P_{school}\ )$

Where:

$P_{school\ max}$ = *Load limit*

P_{school} = *Load - original*

P_{school}' = *Load - adjusted*

Load limits for cables

In this demo case the current or load on Cable 1 between the *400 V busbar* and the *Workshop* is restricted to max 100 % of its thermal limit. This restriction is modelled by comparing the total load with the calculated load (limit) which gives 100 % load on the cable. If the total load is higher than the limit, then the load *Grocery Store* is reduced corresponding the difference between the total load and the limit. If it is not enough to reduce the load *Grocery Store*, then the load *School* is also reduced. This is modelled the same way in both deterministic and probabilistic model. The IF-function in Excel is also used in this case:

Grocery store:

$IF\ (P_{total} > P_{total\ max}$

$\quad IF\ (P_{total} - P_{total\ max} > P_{g\text{-}store}$

$\quad\quad P_{g\text{-}store}' = 0$

$\quad\quad P_{g\text{-}store}' = P_{g\text{-}store} - (P_{total} - P_{total\ max})$

$\quad P_{g\text{-}store}' = P_{g\text{-}store}\ )$

Where:

$P_{total\ max}$	*= Total load limit*
P_{total}	*= Total load*
P_{school}	*= Load school - original*
P_{school}'	*= Load school – adjusted*
$P_{g\text{-}store}$	*= Load grocery store - original*
$P_{g\text{-}store}'$	*= Load grocery store - adjusted*

School:

$IF\ (P_{total} > P_{total\ max}$

$\quad IF\ (P_{total} - P_{total\ max} > P_{g\text{-}store}$

$\quad\quad P_{school}' = P_{school} - (P_{total} - P_{total\ max} - P_{g\text{-}store})$

$\quad\quad P_{school}' = P_{school}\ )$

$\quad P_{school}' = P_{school}\ )$

11.4 Generator models

The model in Figure 11-1 includes one distributed generator (DG). Since it is connected to the low voltage network it is thought to be renewable generation from photovoltaics. The generator is modelled as a 50 kW solar power plant.

11.4.1 Deterministic generator model

Generation have traditionally in NTE Nett been modelled deterministically as either full or no generation, i.e. in this case 50 kW or 0 kW. This model is also used in this demo case for the deterministic calculations.

11.4.2 Probabilistic generator model

Generators can in principle, be modelled in the same way as loads with the use of data from smart meters. Each generator will have its own individual variation curve and distribution function describing the stochastic variation in generation. Since NTE Nett so far has no data from photovoltaic generation, the generation in this case is just modelled as a Beta function. The generation could have been modelled different, but for the purpose of this demo case, this model is good enough.

The Beta distribution has two main uses:

- As the description of uncertainty or random variation of a probability, fraction or prevalence.
- As a useful distribution one can rescale and shift to create distributions with a wide range of shapes and over any finite range. As such, it is sometimes used to model expert opinion, for example in the form of the PERT distribution.

The Beta distribution has two parameters α and β. The Beta distribution is the conjugate prior (meaning it has the same functional form, therefore also often called “convenience prior”) to the Binominal likelihood function in Bayesian inference and, such, is often used to describe the uncertainty about a binominal probability, given a number of trials *n* have been made with a number of recorded successes *s*. In this situation, α is set to the value (s+x) and β is set to (n-s+y) where Beta(x,y) is the prior. [46]

The probability distribution function for the Beta distribution [46]:

$$f(x) = \frac{(x)^{\alpha-1}(1-x)^{\beta-1}}{B(\alpha,\beta)} \qquad where\ B(\alpha,\beta) is\ a\ Beta\ function \tag{11-3}$$

Assumptions about maximum and mean generation are made and the values of α and β in the Beta function is found by trial. Table 11-7 summarizes the results.

Table 11-7 Generation models - Photovoltaics

	Maximum generation [kW]	Mean [kW]	Distribution function
Winter day	25	4	Beta(2,10)
Winter night	0	0	-
Summer day	50	36	Beta(10,4)
Summer night	25	7	Beta(4,10)

The three generation models in Table 11-7 are presented in Figure 11-13 and Figure 11-14.

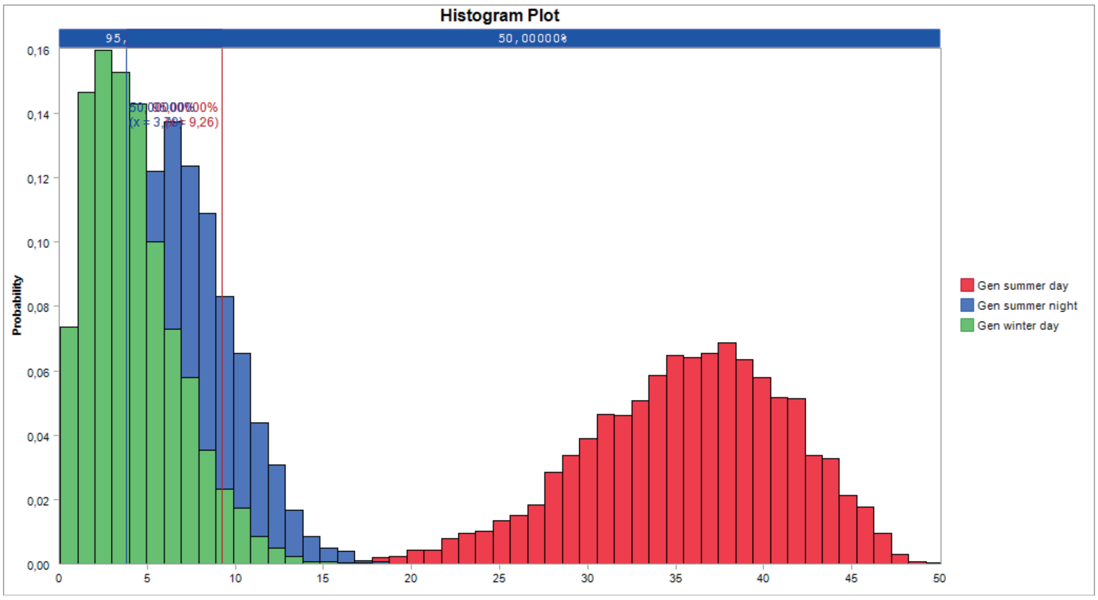


Figure 11-13 Probability distributions – generation histogram

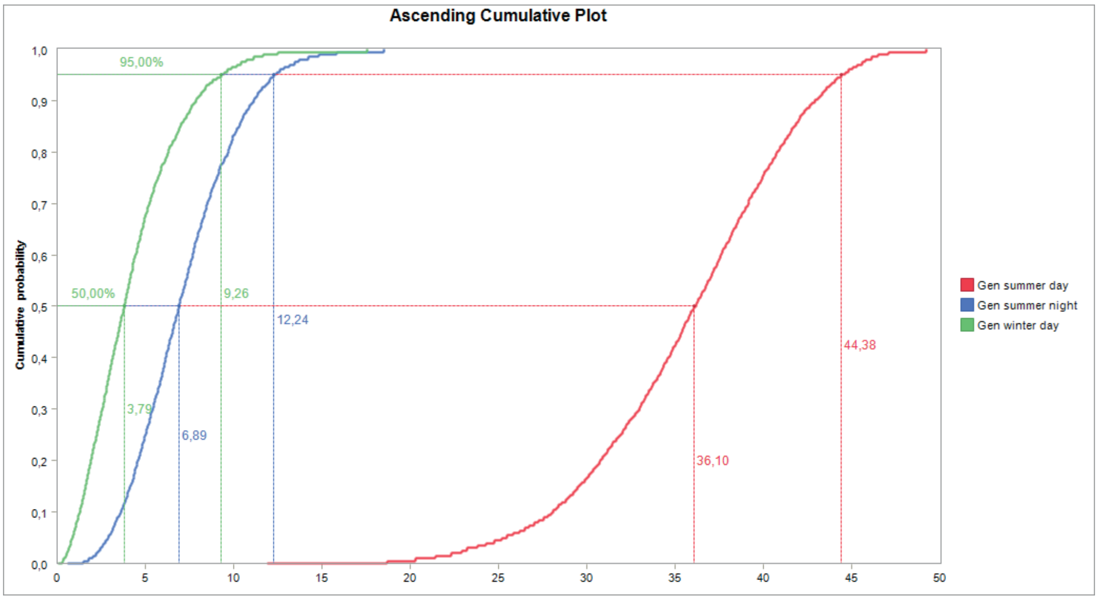


Figure 11-14 Probability distributions – generation ascending cumulative

The y-axis expresses probability in Figure 11-13 and cumulative probability in Figure 11-14, both as a value between 0 and 1. The x-axis expresses generation in kW in both figures. Statistics for the generation models are presented in Table 11-8.

Table 11-8 Generation models - Statistics

Variable Name	Summer day	Summer night	Winter day	Winter night
Location				
Mean	35,63	7,15	4,21	0,00
Minimum	11,92	0,58	0,06	0,00
Maximum	49,22	18,51	17,56	0,00
Percentiles				
1,00%	20,32	1,80	0,37	0,00
5,00%	25,18	2,84	0,85	0,00
10,00%	28,01	3,57	1,27	0,00
20,00%	30,75	4,57	1,90	0,00
30,00%	32,91	5,38	2,54	0,00
40,00%	34,57	6,14	3,14	0,00
50,00%	36,10	6,89	3,79	0,00
60,00%	37,59	7,66	4,42	0,00
70,00%	39,11	8,50	5,20	0,00
80,00%	40,77	9,66	6,26	0,00
90,00%	42,87	11,09	7,83	0,00
95,00%	44,38	12,24	9,26	0,00
99,00%	46,47	14,85	11,68	0,00

Figure 11-13, Figure 11-14 and Table 11-8 show that the Beta functions fit the assumptions in Table 11-7 relatively good.

11.5 Simulations

Load flow calculations are done with Microsoft Excel and ModelRisk – a Monte Carlo simulation risk analysis add-in for Microsoft Excel. Since Excel have no option for detailed simulation of a whole year of hourly values, only two load situations are simulated in this case:

- Winter load – in this case defined as Hour 11 in February.
- Summer load – in this case defined as Hour 11 in July.

Ten different simulation alternatives are investigated with four different load model alternatives. These are presented in Table 11-9 and Table 11-10.

Table 11-9 Simulation alternatives

#	Load situation	Demand response (DR)	Generation (DG)
1	Winter	-	0
2	Winter	Max 90 kW at School	0
3	Winter	Max 100 % on cables	0
4	Winter	-	50 kW
5	Winter	Max 90 kW at School	50 kW
6	Winter	Max 100 % on cables	50 kW
7	Summer	-	0
8	Summer	-	50 kW
9	Summer	Max 90 kW at School	50 kW
10	Summer	Max 100 % on cables	50 kW

Table 11-10 Load model alternatives

Load model	Peak load	Load variation curves	Distribution function
Deterministic 1	Calculated	Standard	-
Deterministic 2	Calculated	Individual	-
Deterministic 3	Metered	Individual	-
Probabilistic	Metered	Individual	Yes

The different load and generator models are described in Chapter 11.2 and 11.4 respectively.
The Deterministic 1 model have been used up till today in NTE Nett and many other utilities in Norway.

The following results are calculated for each of the ten alternatives:

- Loads
- Voltages at every node in the grid
- Branch currents in every transformer and cable in the grid
- Load on transformers and cables in percent of thermal limits
- Total active losses

For the probabilistic calculations, the 0, 50, 95 and 100 % values are presented.

11.6 Simulation results

Detailed results from the simulations are presented in *APPENDIX A – Demo case – calculation results*. This chapter will only give some examples and show some typical results from the simulations.

Deterministic calculation of total load for an electric grid like the one used in these simulations (see Figure 11-1), during one specific hour will provide an answer with one single value. A probabilistic calculation using distribution functions and Monte Carlo simulations will provide an answer described by a new distribution function, as shown in Figure 11-15.

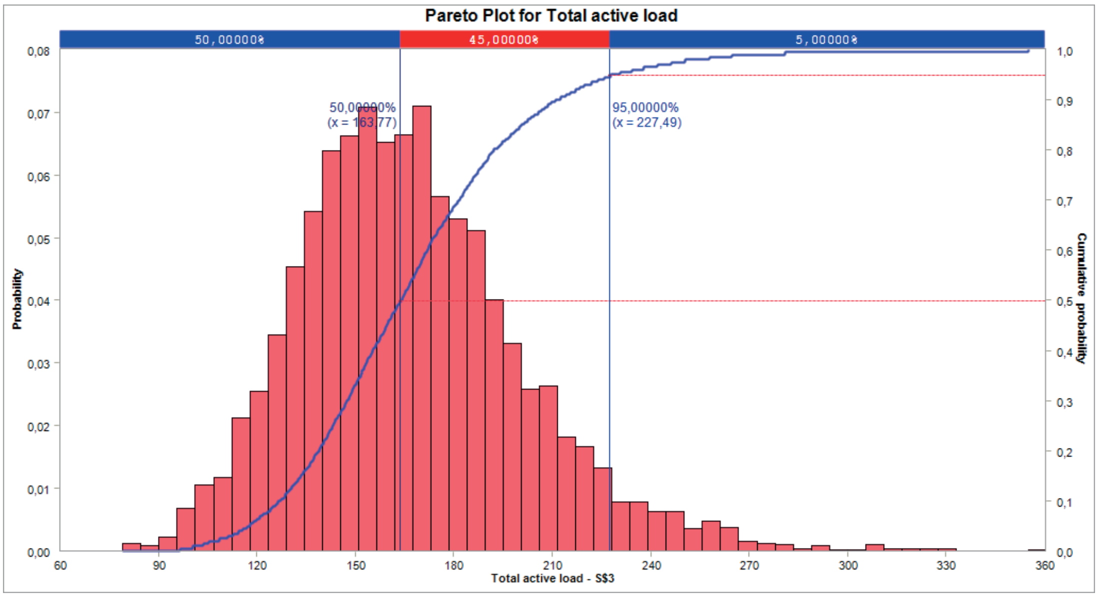


Figure 11-15 Total load - Winter - probabilistic calculation

The axes in Figure 11-15 represent:

- x-axis is total load in kW
- y1-axis to the left is the probability for the occurrence of each value of total load (the bars)
- y2-axis to the right is the cumulative probability for the occurrence of a load that is lower than the specific value (the blue line)

The 50 and the 95 percentiles are also marked in the figure with their respective x-values. Any other percentile of interest can be presented.

11.6.1 Aggregated load and generation

Aggregated load and generation is the resulting power supplied through the distribution transformer, i.e. aggregation of every load and generator in the grid. Aggregated load and generation (total load) are calculated for the 10 simulation alternatives in Table 11-9 and the four different load alternatives in Table 11-10. For the probabilistic calculation the 0%, 50 %, 95%, 99 % and the 100% percentiles are presented. The 0% and 100% percentiles are equal to the minimum and maximum values respectively.

Table 11-11 Aggregated load and generation (kW)

Alternative	Det. 1	Det. 2	Det. 3	Prob. 0 %	Prob. 50 %	Prob. 95 %	Prob. 99 %	Prob. 100 %
1	234	214	311	79	164	227	265	355
2	234	214	264	71	164	208	225	256
3	234	214	250	77	164	230	250	250
4	234	214	311	59	155	220	257	397
5	234	214	264	69	156	202	216	247
6	234	214	300	65	157	223	250	250
7	93	180	186	51	120	147	158	182
8	93	180	186	16	84	113	124	164
9	93	180	186	14	84	112	125	148
10	93	180	186	17	84	113	126	157

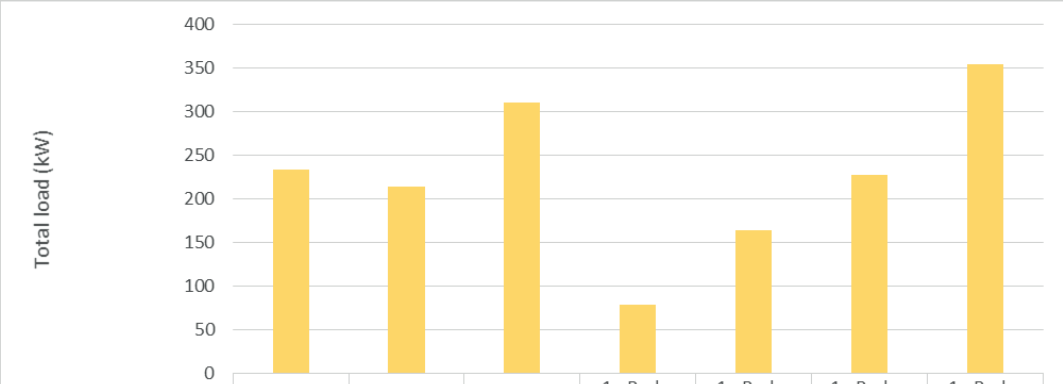
Table 11-12 Total generation (kW)

Alternative	Det. 1	Det. 2	Det. 3	Prob. 0 %	Prob. 50 %	Prob. 95 %	Prob. 99 %	Prob. 100 %
1	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0
4	-50	-50	50	-34	-7	-2	-1	0
5	-50	-50	-50	-34	-7	-2	-1	0
6	-50	-50	-50	-30	-7	-2	-1	0
7	0	0	0	0	0	0	0	0
8	-50	-50	-50	-49	-36	-25	-21	-14
9	-50	-50	-50	-49	-36	-26	-21	-12
10	-50	-50	-50	-49	-36	-25	-21	-12

The total generation in Table 11-12 has opposite sign according to the load. This means that the 0 –percentile (or the smallest value) represents maximum generation and the 100-percentile (or the largest value) represents minimum generation.

Modelling of load and generation is very crucial to how the results become. The deterministic models usually represent extreme situations and give no information about probabilities. The models are not very flexible and might lead to wrong conclusions. The probabilistic models result in distributions with information about probabilities (see Figure 11-15). If the probabilistic model is made by using a wrong stochastic distribution function, then the result will be wrong and might lead to wrong conclusions.

Figure 11-16 illustrates the results graphically for Alternative 1. The probabilistic results presented in Figure 11-15 and Figure 11-16 are for the same load and based on the same simulation.



	1 - Det. #1	1 - Det. #2	1 - Det. #3	1 - Prob., 0%	1 - Prob., 50%	1 - Prob., 95%	1 - Prob., 100%
Generation	0	0	0	0	0	0	0
Load and generation	234	214	311	79	164	227	355

Figure 11-16 Simulation 1 - Winter load – Total load

According to the probabilistic model used in this case, the different probabilities for the deterministic loads are (see Figure 11-17):

- Det. #1 (234 kW) : 96,0 %
- Det. #2 (214 kW) : 90,9 %
- Det. #3 (311 kW) : 99,8 %

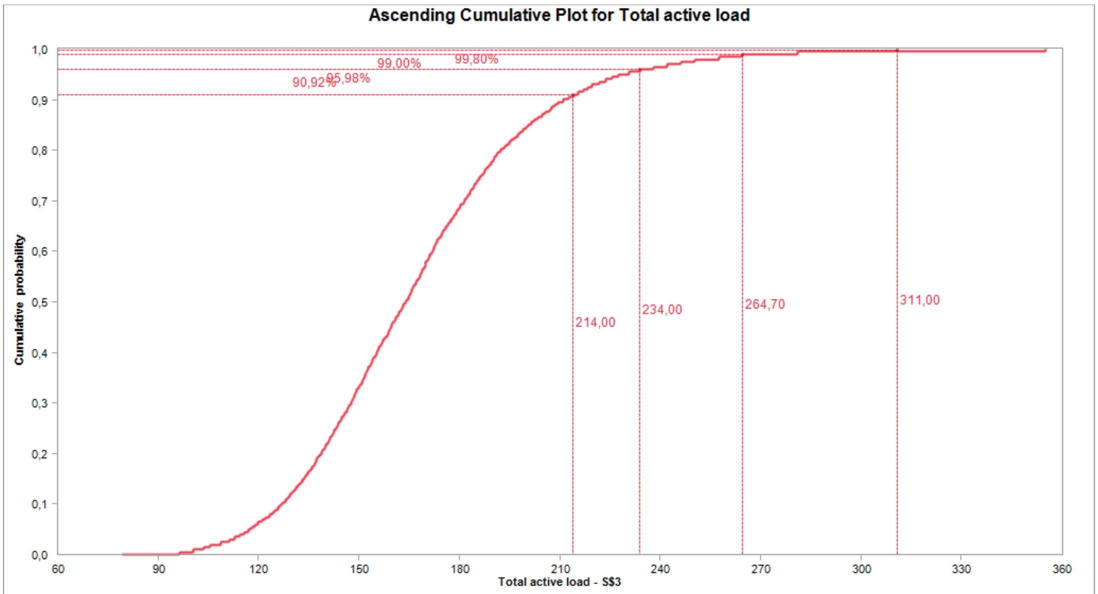


Figure 11-17 Total load – cumulative – Simulation 1 – Winter load

The 99-pecentile in Figure 11-17 is 265 kW.

11.6.2 Voltages

Voltages are calculated for every node in the model. The voltage at the feeding point is fixed at 400 V.

It is of interest to find out if voltages in the grid are within the limits of ± 10% or not. Figure 11-18 shows calculated voltages during winter load.

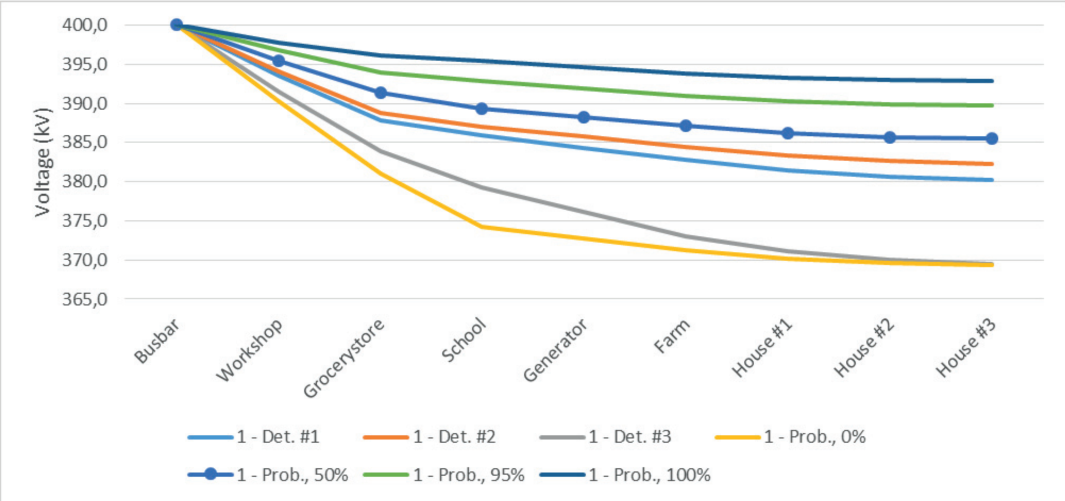


Figure 11-18 Calculated voltages – Simulation 1 – Winter load

In this case it is interesting to look at the voltage at the outermost end of the grid, i.e. at House #3. The minimum voltage at House #3 is approximately 370 V with two of the models. Figure 11-19 presents the result from a probabilistic calculation of voltage at House #3.

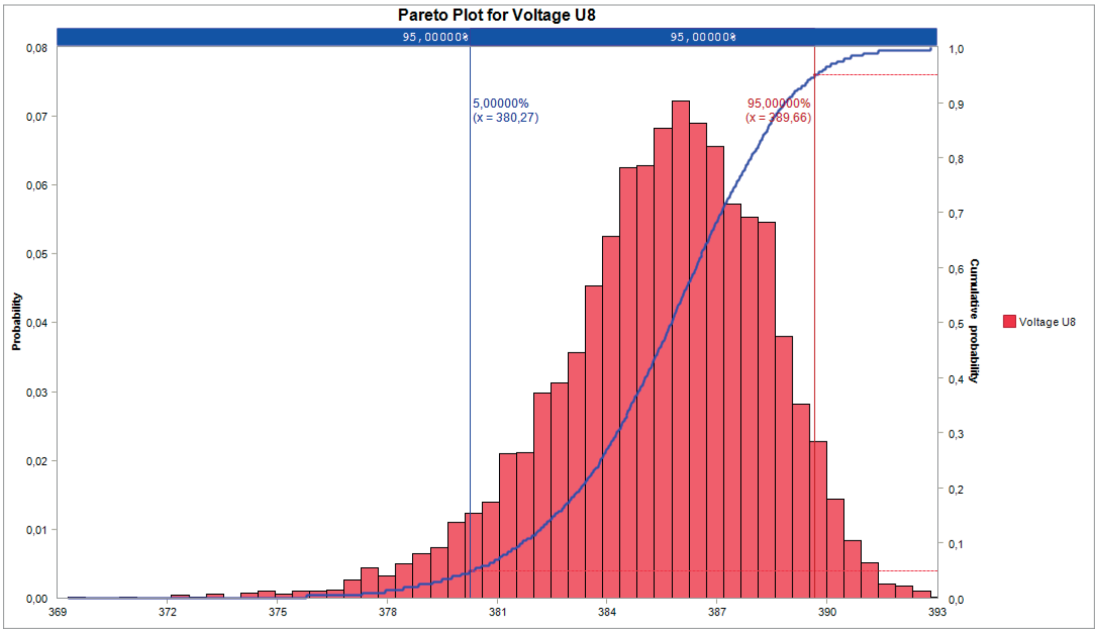


Figure 11-19 Voltage House #3 - Simulation 1 - Winter load – Probabilistic model

The minimum value is 369 V and the maximum is 393 V. The probabilistic calculation also tells us that there is only a probability of 5 % that the voltage in this node will be lower than 380 V.

11.6.3 Branch currents and loads

Currents through transformer and cables and the relationship between these currents and the corresponding thermal load limit for transformer and cables are calculated. The branch current as a percent of the thermal limit is of great interest when considering the grid capacity.

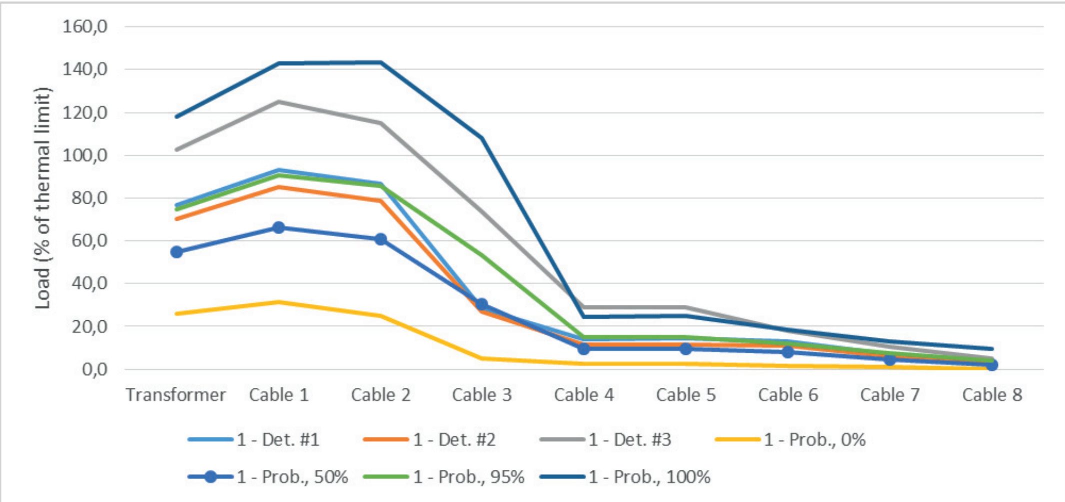


Figure 11-20 Load on transformer and cables - Simulation 1 - Winter load

According to Figure 11-20, the transformer and the three first cables might be overloaded. Both the deterministic model #3 and the probabilistic model results in more than 100 % load in these parts of the grid. The deterministic models (# 1 and 2) based on calculated peak load underestimates the load and do not indicate probability of overloaded transformer and cables. An overload of Cable 1 is most likely to happen.

Figure 11-21 shows an ascending cumulative plot for load in Cable 1 in % of its thermal limit. According to this figure, the probability of overloading Cable 1 in this situation is 2,1 %. Increasing the capacity of the cable by over 40 % (fit-and-forget) to avoid overload, will probably be an expensive solution to this problem. It can be worth looking for some other solutions like e.g. generation control, demand response (DR) or demand side management (DSM).

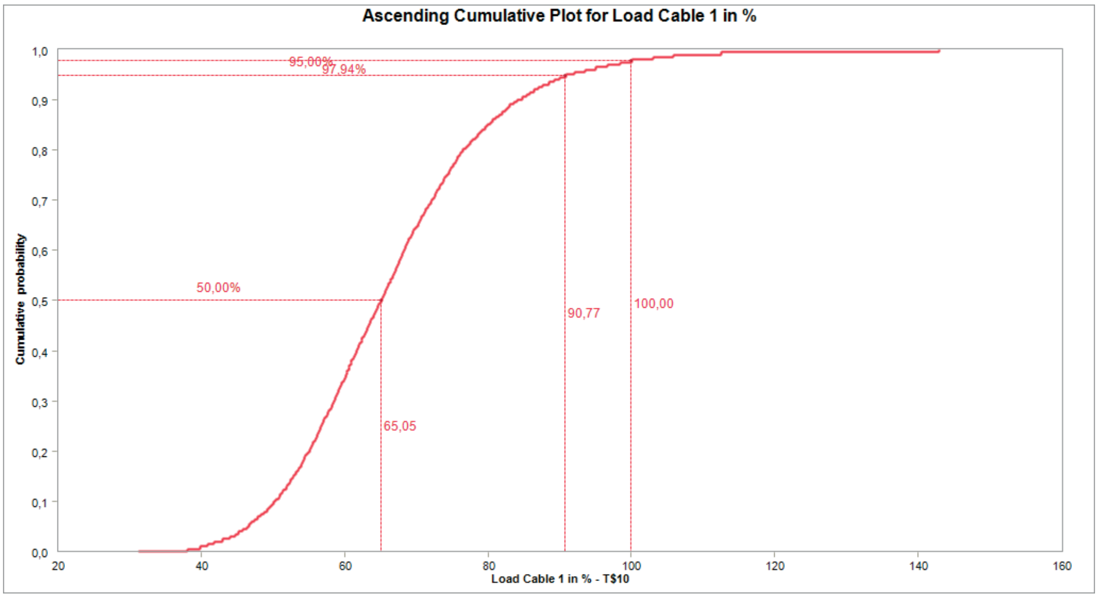


Figure 11-21 Load on Cable 1 in % - Simulation 1 - Winter load

11.6.4 Network losses

Probabilistic load models result in probabilistic models for the total active losses as well. The losses are of interest for economic reasons in evaluation of investment plans and estimating operational costs. Figure 11-22 shows total losses for Simulation 1, winter load. For economic evaluation, the total losses in kWh/year is of interest. This value is not possible to calculate with the model and calculation tools used during this PhD-work.

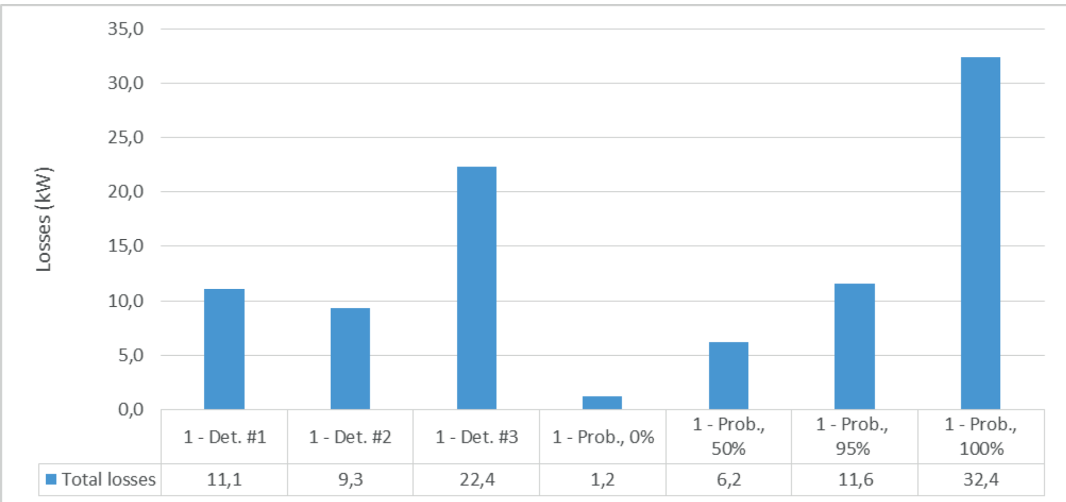


Figure 11-22 Total losses - Simulation 1 - Winter load

PART V – Discussion and conclusion

12 Discussion

This chapter discusses some of the results presented in previous chapters.

12.1 State of the art

The first part of this thesis (Chapter 2, 3 and 4) describes how things usually have been done by Norwegian utilities up to today regarding power system planning. Today's method is characterized by:

- Using a deterministic method for modelling of loads and generation
- Grid dimensioning according to a Fit-and-forget approach
- Grid operators are according to Norwegian regulation, not allowed to set restrictions on generation from power stations connected to the grid (chapter 4.7). Power stations connected to the grid shall be able to generate 100 % of time. The utility can only put temporary restrictions on generation in e.g. anticipation of planned expansion of grid capacity.
- The consumer or producer of electric energy responsible for the grid reinforcement related to connecting of new load or generation shall pay costs for the necessary reinforcement.

The disadvantages (cons) of this practice are:

- A poor utilization of the grid capacity i.e. the grid is over dimensioned
- The costs for grid reinforcement are unnecessarily large
- The large costs for grid connection of new generation represents a barrier for development of RES
- Some parts of the grid are built only to satisfy the requirement for 100 percent grid capacity for every situation.
- Unnecessary high maintenance cost due to unnecessary size of the distribution grid

The advantages (pros) of this practice are:

- A safe and robust distribution grid that can handle any load/generation situation
- No active management is needed

Better load models can be made with data from smart meters (available in Norway from 2019), and this will probably improve the results from the deterministic method compared to today. The question is if the deterministic fit-and-forget method is good enough for the future distribution grid.

12.2 The future distribution grid

The second part of this thesis describes why and how the distribution grid is changing. The focus on climate change and energy efficiency are the main drivers for change in the distribution grid – changes that will affect the power system planning and operation (Chapter 5, 6, 7 and 8):

- The use of fossil fuels is gradually reduced and replaced by renewable energy sources (RES).

- The amount of RES connected to the distribution grid is increasing:
    - Bioenergy and geothermal energy are mainly associated to heat generation and not to electricity generation – at least not as small generation units connected to the distribution grids.
    - Ocean energy is in Norway usually located by the coast far from distribution grid and load. Research and prototype testing is going on, but so far ocean energy is mainly used in small single installations at sea.
    - Direct solar energy, hydropower and wind energy will have the greatest impact on the distribution grids in terms of distributed generation (DG) in the nearest future. The amount of photovoltaics connected to the distribution grids in Norway is increasing rapidly. The

Norwegian government through ENOVA[19] has funding schemes to stimulate both private and business to install photovoltaics for electricity generation. In Norway there is a great potential for utilization of small watercourses and connect small hydroelectric power stations to the distribution grid.

- Electricity generation from RES is usually fluctuating and has a certain stochastic character, i.e. the generation varies in time the same way as the solar radiation/cloud variation, the wind speed or the available water in the river. There are no reservoirs available, so RES cannot respond to a request for more power by increasing its generation. Battery energy storage systems (BESS) is about to become more common and more used to help solve this problem with fluctuating generation from RES, but is still expensive compared with thermal storage/demand response.

- Energy efficiency is also a means to mitigate climate change. This has led to many good actions, new and improved equipment's and appliances. Some of these, however, have also led to problems regarding power quality in the distribution grids. Tank-less water heaters, heat pumps and induction cooktops are some common appliances today that are energy efficient, but high-powered. Increased use of this type of appliances results in increased load fluctuations – increased in both amplitude and frequency with a certain stochastic character.

- Smart Grids is described as a tool for cost efficient RES and active customer integration. The term Smart grids includes today most of the issues involved in planning, operation and maintenance of the electrical power system, including issues concerning the interaction with the distribution grid customers (generation, consumption, Smart House).
    - Extended use of control equipment, sensors and ICT in the distribution system will make it possible to connect more RES to the distribution grid, controlling the load flow in the grid and make the grid more robust regarding operational disturbances.

- The DSO will get a lot more data from meters, sensors, control systems etc. that can be used to make better long-term plans for grid development.

Today's fit-and-forget approach used on a distribution system with increased fluctuations in consumed and generated power, would probably result in even poorer utilization of the grid capacity since the grid will be dimensioned after the two extreme situations:
1) maximum load and minimum generation
2) minimum load and maximum generation

With a relatively large amount of RES connected to the grid, the minimum load/maximum generation situation will be decisive for the "necessary" grid capacity. Since restrictions on generation from power stations connected to the grid cannot be set, the maximum generation (theoretically) will probably be considerably higher than real maximum generation. It will be unnecessarily expensive for the DSO to continue to follow the traditional deterministic fit-and-forget approach in the future.

Stochastic variations in both load and generation results in larger uncertainty concerning the variation in the aggregated load. Power system planning in the future smart and active distribution system should therefore be done with the use of:
- Probabilistic models for load and generation.
- Probabilistic calculation tools like Monte Carlo simulations for network calculations.

[19] ENOVA – a public enterprise that is owned by the Ministry of Petroleum and Energy. Their goal is to strengthen he work in converting energy consumption and generation into becoming more sustainable, while simultaneously improving supply security (www.enova.no)

- Active management (no-network solution) like demand response and generation control included in the planning methodology to reduce the risk of constraint violation. If active management does not solve the problem alone, then network solutions or a combination of non-network and network solutions can be evaluated.

12.3 Probabilistic models for load and generation

A method for making probabilistic models for load and generation with the use of data from smart meters is described in Chapter 10. Four different alternatives for load modelling are investigated, tested and compared to the real metered data used as basis for the models (see Table 10-4).

When comparing the average values for the seven different load models made according to the four alternatives, it appears that the relative deviation between measured and calculated values in the two alternatives A and C using average values as a reference, is larger than in the two alternatives B and D using maximum (peak) values as a reference. The deviation is larger both in extreme values and in standard deviation. This means that load models made according to alternative B and D give better results than the two other alternatives, i.e. load models should use peak values as reference. The difference between alternative B and D in this case is negligibly small. This means that the load model using different daily load variation curves for each month does not give a significantly better result than the load model using the same daily variation curves for the whole year. This should however be investigated further when more data are available. Three years with data might be too little to define the 24 different load variation curves in alternative D. Only three load variation curves are defined in alternative B. Load models made according to alternative B is therefore used for further investigation in the case study (Chapter 11).

The principles for the deterministic and probabilistic load models used for the evaluation are summarized in Table 12-1.

The load models consists of:

- Peak load as a reference
- A yearly variation curve describing how the load varies monthly during the year.
- Two daily variation curves (workdays and weekends/holidays) describing how the load varies hourly during the day.
- For the probabilistic model: A distribution function describing the stochastic variation around the expected load

Table 12-1 Deterministic and probabilistic load modelling used in this evaluation

Description	New method with smart meters	Old method without smart meters
Load reference	Metered peak load (kWh/h) for every individual load	Calculated peak load with the use of standard utilization times and annual energy consumption. Standard utilization times for only a few consumer categories are used (e.g. household, office building, industry, agriculture, school, etc.).
Basis for load variation curves describing expected load	Calculated for every single load based on metered hourly energy consumption (kWh/h) for the last 3 years.	Standard load variation curves for only a few load categories are used (e.g. household, office building, industry, agriculture, school, etc.).
Number of load variation curves	One yearly variation curve and two daily variation curves (workdays and weekends/holidays).	One yearly variation curve and two daily variation curves (workdays and weekends/holidays).
Modelling of uncertainty	Individual stochastic variable described by a distribution function. Several distribution functions are tested and the one that fits the data best is chosen.	Not modelled
Load aggregation and aggregated peak load	Aggregated load can be modelled the same way as single loads. By summing the metered load (kWh/h) for the single loads and using the highest (peak) value as a reference, load variation curves and distribution function for the aggregated load can be found. As an alternative, aggregated load can be found by summing the corresponding hourly values from the single load models. This summing can also be done by performing load-flow calculations with the models for the single loads. To find the aggregated peak load, corresponding hourly values from the single load models must be summed for every hour of the year. Monte Carlo simulations should be used for the summing operation in order to take into account the stochastic variation in the load.	Aggregated load can be found by summing the corresponding hourly values from the single load models. This summing can also be done by performing load-flow calculations with the models for the single loads. To find the aggregated peak load, corresponding hourly values from the single load models must be summed for every hour of the year. Since standard load variation curves are used in the single load models, load coincident factors must be used to reduce the sum of several loads with the same load variation curves. Such factors can be found in literature, e.g. [14]

12.4 Evaluation of the methods

Deterministic and probabilistic load-flow calculations are performed and the results are compared to each other in order to evaluate the methods. Monte Carlo simulations are used to perform the probabilistic load-flow calculations. Ten different simulation alternatives are investigated with four different load model alternatives. These are presented in Table 11-9 and Table 11-10.

12.4.1 How the load models fit the metered data

The deterministic model based on standard utilization times and standard load variation curves does not give a good and reliable model of the load if the load is different from the normal. The loads *Farm* and *Grocery Store* are good examples of deterministic models that do not fit the real load well.

The load *Farm* in this case, is special since in most of the year the load is only a few kW, but in the harvesting season, the grain dryers are occasionally used. This means that electric motors are running fans of total power up to 35 kW. The peak load is high and the utilization time is low. Figure 12-1 shows a Pareto plot for this load during February. The bars in the figure represent the probability distribution of the load and the solid curve represents the cumulative probability of the load.

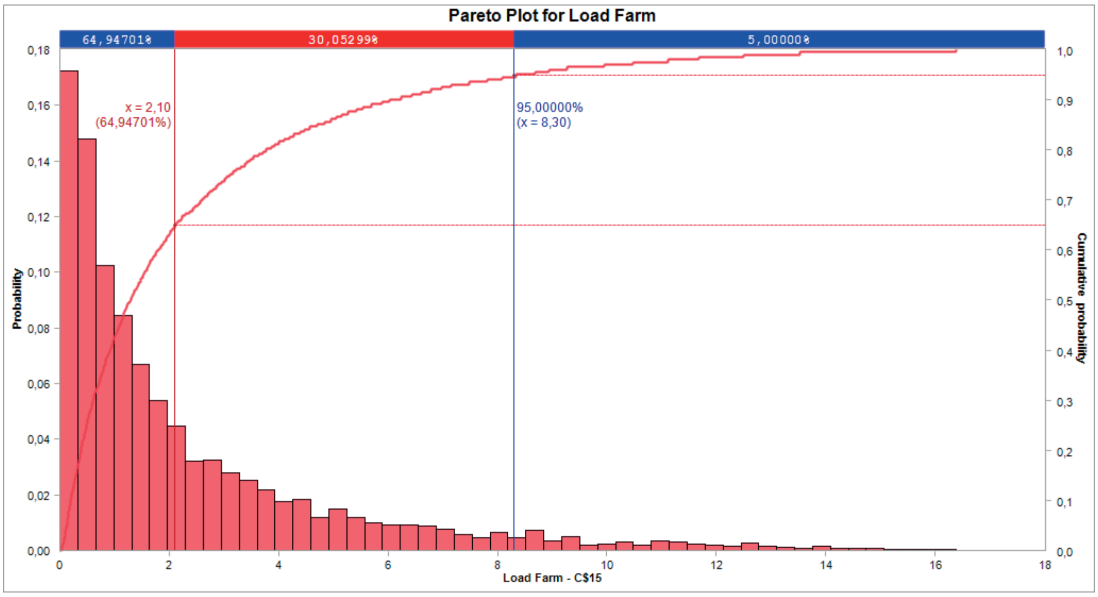


Figure 12-1 Load distribution - Farm - Winter

The deterministic model gives a peak load of 2.1 kW while the probabilistic model gives a peak load (100-percentile) of 16.4 kW (in February). The 95-percentile is 8.3 kWh/h and the 50-percentile is 1.3 kWh/h. Using individual load variation curves and real metered peak load makes it possible to consider these special variations.

Since the loads (and generations) become more stochastic, a probabilistic approach will provide better estimation of loads, currents and voltages in the grid than a deterministic approach will do.

The load G*rocery Store* in this case has opening hours from 07:00 – 23:00 while the standard load profile for retail trading is made for normal opening hours from 08:00 – 16:00. This means that the real load does not follow the standard daily load variation curve. Calculated daily variation curve for the grocery store and the corresponding standard variation curve are shown in Figure 12-2. The difference in opening hours is clearly visible in the figure.

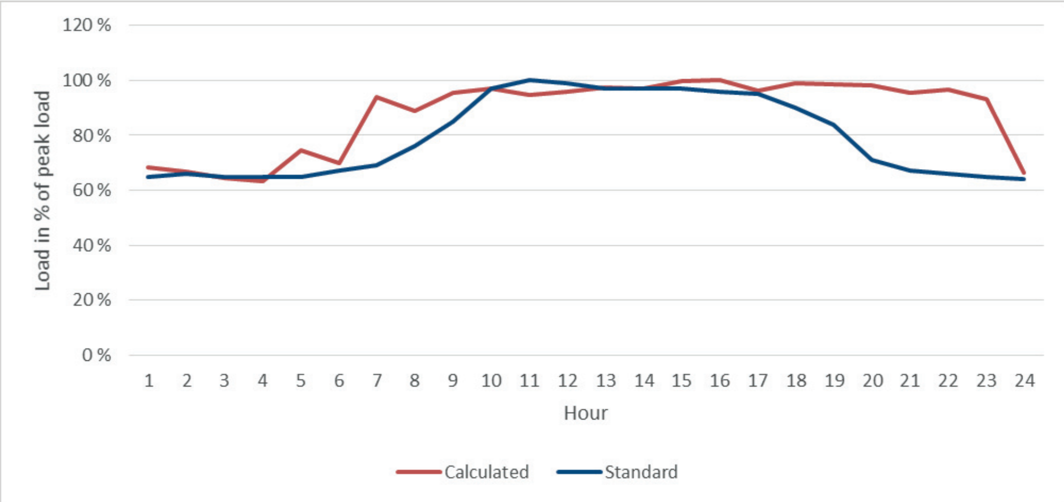


Figure 12-2 Daily variation curves – Grocery store - Winter

The standard load profiles do not suit all loads well, so when low voltage grids shall be analyzed, individual load profiles will give a better and more accurate result. When circumstances change like the opening hours in Figure 12-2, the parameters in the load model must be changed whichever model used. In the deterministic model, new standard load variation curves must be defined for new sets of load categories. By using individual load variation curves, changes in circumstances will automatically be picked up over time, i.e. with a certain time delay.

Four different load models are tested in Chapter 11:

Table 12-2 Load model alternatives

Load model	Peak load	Load variation curves	Distribution function
Deterministic 1	Calculated	Standard	-
Deterministic 2	Calculated	Individual	-
Deterministic 3	Metered	Individual	-
Probabilistic	Metered	Individual	Yes

(Table 12-2is equal to Table 11-10).

The first deterministic model represents today's load modelling. When future deterministic and probabilistic load models shall be compared, the third deterministic load model should be used because, according to the previous considerations:

- Real metered peak load is a better load reference than calculated peak load with the use of annual energy consumption and standard utilization time
- Individual load variation curves gives a better load representation than the standard curves

The difference between the *Deterministic 3* model and the *Probabilistic* model is the extra distribution function in the probabilistic model.

12.4.2 Estimation of total load

When combining several loads and generations in a grid, the deterministic method will use the sum of every peak load as the total peak load. The deterministic method describes usually an extreme situation that rarely or never will occur, since each load within the same load category (e.g. household) has its maximum at the same time. The probabilistic method will combine the distribution functions and calculate the total load as a sum of distribution functions. This will give a better and more accurate picture of the load.

Table 12-3 shows aggregated load and generation for the ten different simulation alternatives investigated for the four different load models.

Table 12-3 Aggregated load and generation (kW)

Alternative	Det. 1	Det. 2	Det. 3	Prob. 0 %	Prob. 50 %	Prob. 95 %	Prob. 99 %	Prob. 100 %
1	234	214	311	79	164	227	265	355
2	234	214	264	71	164	208	225	256
3	234	214	250	77	164	230	250	250
4	234	214	311	59	155	220	257	397
5	234	214	264	69	156	202	216	247
6	234	214	300	65	157	223	250	250
7	93	180	186	51	120	147	158	182
8	93	180	186	16	84	113	124	164
9	93	180	186	14	84	112	125	148
10	93	180	186	17	84	113	126	157

(Table 12-3 is equal to Table 11-11).

The aggregated total load Table 12-3 is larger for every alternative with the *Deterministic 3* model than the 95 percentile with the probabilistic model. Only the two alternatives 1 and 4 (winter load with and without generation) results in a higher load with the probabilistic model's 100 percentile than the *Deterministic 3* model. The probability for maximum load (100 %) in the probabilistic model is however very low, according to Figure 11-15 (simulation alternative 1). The 99 percentile in Alternative 1 is only 265 kWh/h, i.e. less than 75 % of the 100 percentile (355 kWh/h). This means (in this case), that if the DSO can tolerate a one percent risk for overload, or can handle the rare situation with 100 % load with e.g. active load management, the needed grid capacity can be reduced to 75 % compared to the fit-and-forget approach. This also shows that by using probabilistic models for planning purposes and considering active management as an alternative to grid reinforcement, the DSO can achieve:

- A better utilization of the grid capacity
- Reduced costs for grid reinforcement compared to the fit-and-forget approach
- Reduced costs for grid connection of new generation might stimulate the development of new RES projects

12.4.3 Network calculations

Performing network calculations by using Monte Carlo simulations and probabilistic models for loads and generation provides results (currents, voltages, losses, etc.) presented as distributions. Information about the distribution of loads and risks for overload can be very useful. The risk can be acceptable as it is, or reduced by introducing measures like for example demand response and load shedding.

Figure 12-3 shows the load on cable 1 in the case during winter load (alternative 1,Table 11-9). There is a 97.9 % probability that the cable will not be overloaded. The 95 percentile is 90.8 % and maximum load is about 140 % of the thermal limit. According to the Deterministic 3 model, the corresponding maximum load is about 125 % of the thermal limit.

If demand response is introduced at the load *School* by limiting the load to maximum 90 kW, it will look like Figure 12-4. This DR will reduce the maximum load on cable 1 to about 100 % of the thermal limit. The new distribution of the load in cable 1 is shown in Figure 12-5. According to the Deterministic 3 model, the corresponding load is about 105 % of the thermal limit.

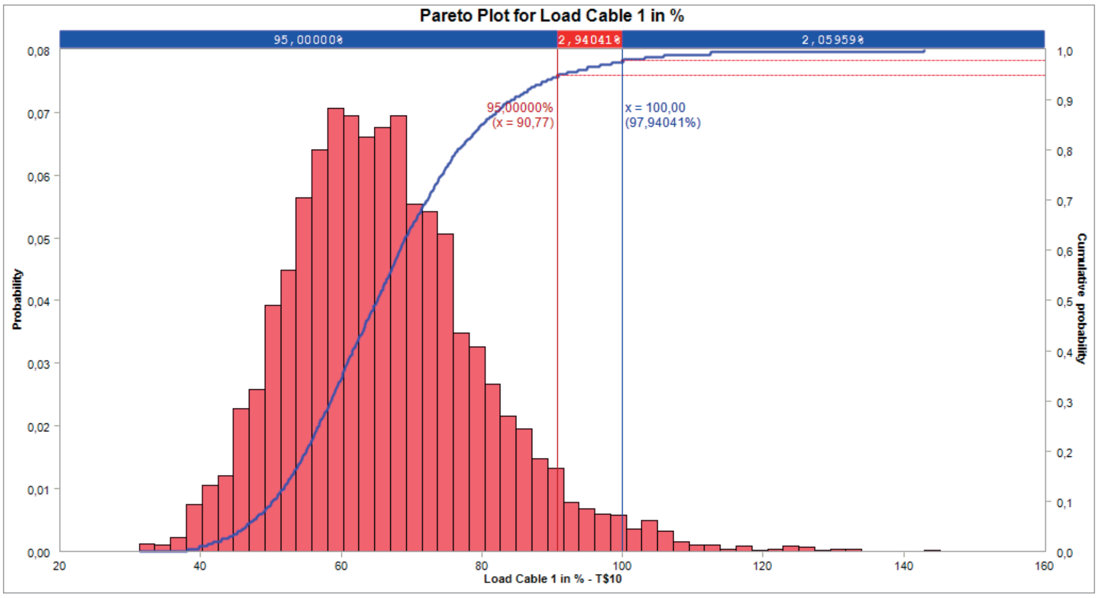


Figure 12-3 Load on Cable #1 in % – Winter

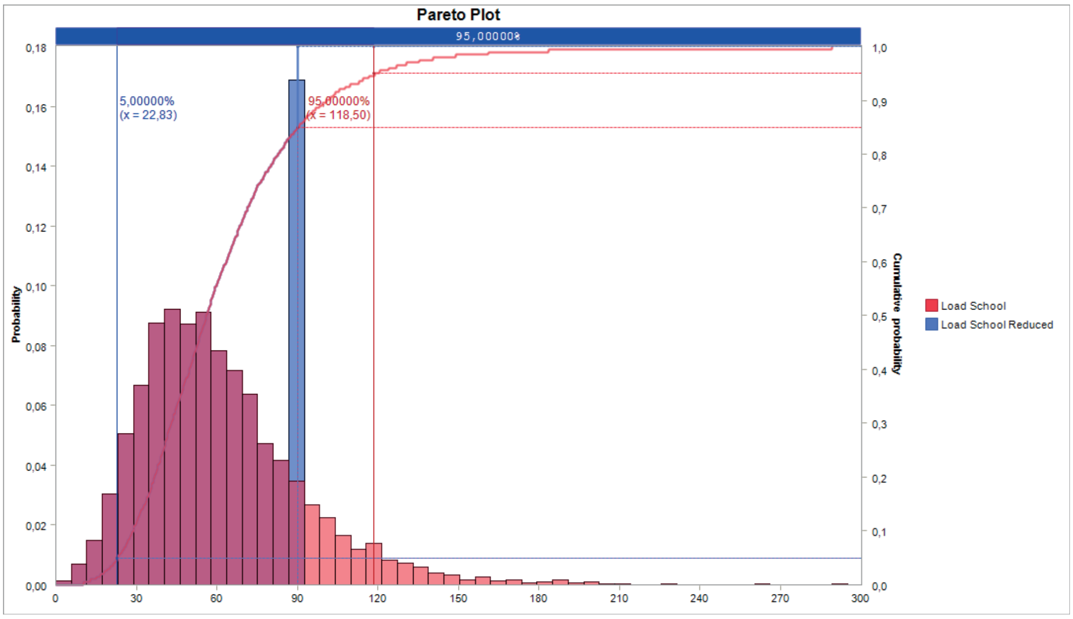


Figure 12-4 Load School - With and without DR (max 90 kW at School) – Winter

The curves in Figure 12-4 are the result of 5000 Monte Carlo simulations. In 748 of these simulations the load is reduced to 90 kW due to DR. This represents in this case a 6.3 % reduction of the energy consumption (assuming that the reduced energy was not replaced at a later moment).

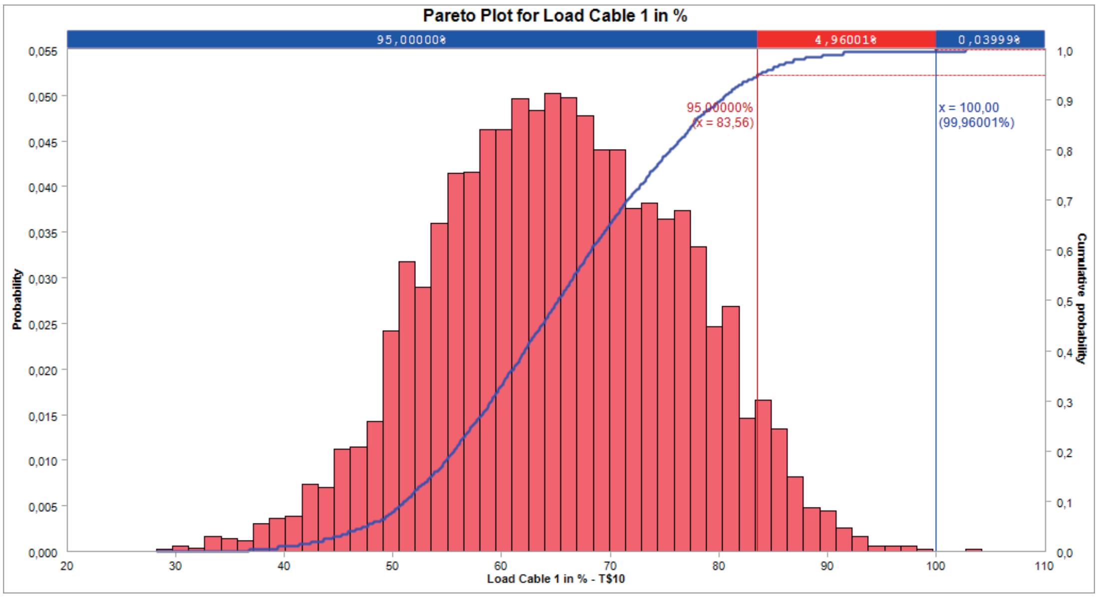


Figure 12-5 Load on Cable #1 in % with DR (max 90 kW at School) – Winter

These examples show how useful probabilistic models and Monte Carlo simulations can be compared to the deterministic fit-and-forget approach. The probabilistic approach will provide the DSO and the power system planner with a lot of new valuable information that can be useful for the planning and operational purposes. It is very essential that power system planning and operational issues are based on good and reliable models for load and generation. Poor models may lead to poor and wrong decisions.

Probabilistic models made for the LV network can be aggregated to higher voltage levels, or time series with metered energy transmissions in higher voltage levels can be modelled the same way as described for LV loads in this thesis. Probabilistic models will provide better decisions regarding network development in every voltage level, given that the models for load and generation are good enough.

Regarding power quality and the Norwegian grid code, it is the 1-minute values and not the 1-hour values that are of interest. As mentioned in Chapter 10.1, the method used to calculate individual models for load and generation can be used whether the basis are one-hour, 15-minutes or one-minute values. But, as mentioned in Chapter 9.2.1, a time step of one hour is commonly used to represent load and generation profiles and to analyze the impact of operation strategies in the planning studies. If the individual models are based on one-hour or 15-minutes values, but are referred to the one-minute peak value instead of the one-hour or 15 minutes peak value, the Monte Carlo simulation will give an estimation of the 1-minute values and probabilities for exceeding the limits given by the grid code. The one-minute peak value (kW) could in principle be found by the smart meters[20]. An alternative to this method is to use the ratio between the metered one-hour and one-minute peak values for each specific load as a factor for calculating the one-minute value.

[20] Smart meters that are about to be deployed in Norway, must be able to register energy consumption, voltage and power quality data for down to 15-minutes intervals. If 1-minute maximum and minimum values can be registered depends on the type of meter used and the software configuration.

Probabilistic models of load and generation will not directly improve the power quality. The fit-and-forget approach will give an over dimensioned grid which can handle every load situation that might occur. According to the probabilistic approach, the network capacity will be better utilized and the dimensioning is based on risk evaluation. Network constraints can be exceeded, but the use of active management of load and generation can prevent this from happening.

In probabilistic analyses, the technical considerations and dimensioning of the grid are based on the DSOs willingness to take risks. The DSO can decide to accept e.g. 1 or 5 % risk of exceeding a technical constraint like e.g. thermal limit for a cable. Economic considerations on the other hand, like calculating the value of the electrical losses, should be based on average/expected values (50 percentiles). In Norway there are considerable climatic variations from year to year, and about 20-50 % of the electric energy consumption is considered as temperature dependent according to www.enova.no (Table 10-2). Economic considerations should not be influenced by climatic variations and must therefore be based on a normal year (average values). Grid dimensioning according to economic considerations usually provides a good margin above the technical limitations, but this must be checked against technical dimensioning based on extreme values.

12.4.4 Economic considerations

Detailed economic calculations have not been performed during this work, but a subjective estimation can be made based on the results from the case study in Chapter 11. According to *Figure 11-20 Load on transformer and cables - Simulation 1 - Winter load* (page 127), the cables 1 and 2 will be overloaded in the alternatives *Deterministic #3* and *Probabilistic 100%.*

If the "fit-and-forget" approach is used, the grid should be reinforced with some new cables. One possible solution in this case, is to divide the feeder in two, e.g. the first two consumers (workshop and grocery store) can be supplied by a separate new cable from the distribution transformer, while the rest of the consumers are supplied by the existing cables. This is illustrated in Figure 12-6. This solution may e.g. involve 200 meters with new underground cable. 200 meters with new cable TFXP 4x240 AL included trenching, cable conduit and ground wire, will cost about 145.000 NOK or 17.000 EUR according to the *Distribution Cost Catalog 2016* in [14].

If the new probabilistic approach is used, this grid reinforcement might be deferred. According to *Figure 11-21 Load on Cable 1 in % - Simulation 1 - Winter* load (page 128), the probability for overloading the cable (Load Cable 1 = 100 %) is only 2 %. If this risk is considered acceptable by the utility, or if demand side management (DSM) can be used to reduce the load in these relatively rare strained situations, then grid reinforcement may be deferred assumed without any cost.

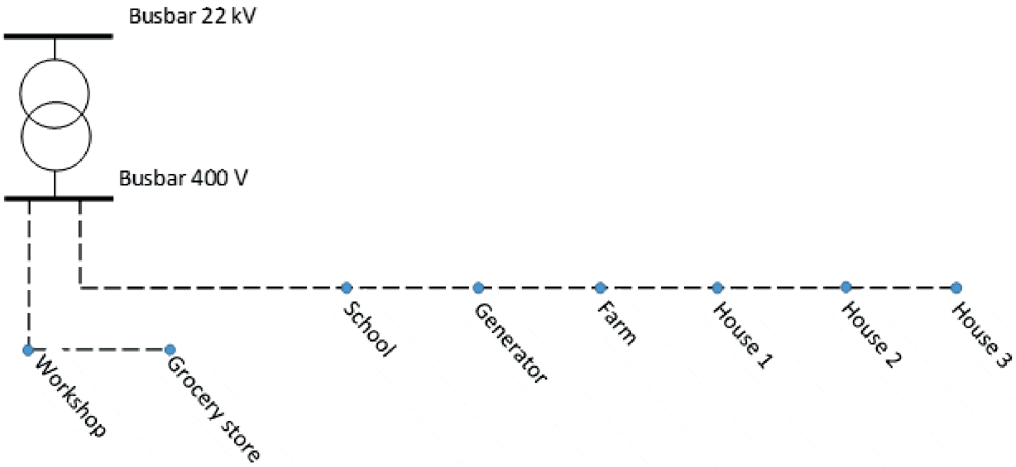


Figure 12-6 Alternative configuration - Fit-and-forget

Figure 12-7 shows an example of how the present value of an investment can be reduced due to deferment of the investment time. The curve is based on the assumption of:

- 2 % yearly operation and maintenance costs related to the amount invested
- Discount rate: 4.5 % p.a.
- Analysis period: 30 years
- Economic life of the cables: 35 years
- Electrical losses: Changes due to the investment are ignored
- Power quality and cost of energy not supplied (CENS): Changes due to the investment are ignored

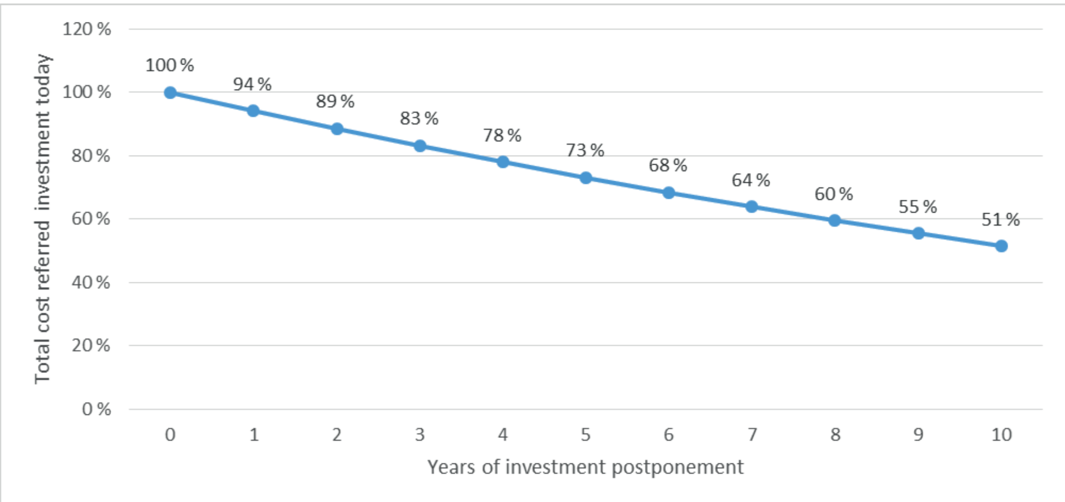


Figure 12-7 Example of reduced total socioeconomic costs (present values) due to a deferred investment

If the use of the new probabilistic approach makes it possible to defer an investment for e.g. 5 years, the present value of the investment will, according to Figure 12-7, be reduced to 73 % compared to the alternative of investing today according to the fit-and-forget approach.

12.5 Practical applications

Probabilistic calculations can be used for different purposes in power system planning:

Making long-term development plans for the grid.

Good probabilistic models for loads, generations and future prognosis will make it possible to simulate future load flow and probable load development in order to make good long-term plans for grids on every voltage level. The fit-and-forget approach results in poor utilization of grid capacity and unnecessary high costs. By accepting some risk of constraint violation and mitigating this risk by using active management schemes, the costs regarding grid reinforcements and development can be reduced considerably compared to today's deterministic method.

Short-term plans

Better models for load and generation connected to the grid improve the quality regarding planning of outages and maintenance in the grid. Network calculations with probabilistic models result in probabilities for constraint violations and makes a better basis for the evaluation regarding possibilities for switching sequences in the grid. This might result in reduced costs for both disturbances and planned disconnections.

Technical dimensioning

For technical dimensioning probabilities for overload and voltage conditions must be analyzed. The DSOs willingness to take risk affects the dimensioning.

Economical dimensioning

For economical dimensioning, the energy losses and probabilities for disturbances and outages must be analyzed. The expected values (50 percentiles) should be used as basis, i.e. average values make the economic considerations independent of the annual climatic variations (explained in Chapter 12.4.3).

13 Conclusions

Based on the findings documented in this thesis, the following conclusions can be made:

1. Focus on energy efficiency and climate change drives the energy generation away from fossil fuel to RES and energy consumption becomes energy efficient but high powered. This change results in larger fluctuations / stochastic variation in both load and generation. Today's deterministic method for modelling load and generation combined with the fit-and-forget approach, results in unnecessary overinvestment in grid capacity. The grid is dimensioned to manage every situation that can possible occur. Using probabilistic models for load and generation will give the DSO a more accurate model of the load situation in the grid and will give results presented as probability distribution functions.

2. Data from smart meters provides valuable information about load and generation. By using metered data for 3 or more years (with time-step of one hour or less), individual load variation curves can be extracted together with a distribution function that best describes the stochastic variation around the expected value. Since loads and generation act individually, individual models for load and generation will fit the metered data better than standard models.

3. Probabilistic load-flow calculations can be done by using Monte Carlo simulations. The method has been tested in a case study, and is found to work properly and provides results (currents, voltages, losses, etc.) presented as probability distributions valuable to the power system planner.

4. Probabilistic calculations give better insight and decisions than today's deterministic calculations since probabilistic calculations give results presented as probability distribution functions instead of the deterministic (one single value) result. Probabilistic methods do on the other hand require higher competence among the user.

5. Power system planning based on probabilistic simulations will give better results – both technically and economically. The overinvestment in grid capacity will be reduced and the exploitation of the grid capacity will be higher.

6. A probabilistic approach results in a better utilization of the grid capacity and grid reinforcements can because of this be deferred compared to the deterministic fit-and-forget approach. The economic profit by deferred investments can be significant. It is shown that a five-year deferment of an investment can reduce the present value of the investment to 73% [21] compared to the invest-today alternative.

Power system planning in the future should be performed with individual probabilistic load and generation models and Monte Carlo simulations for load flow calculations. The new model described in this thesis should be adapted to existing software planning systems.

[21] Based om assumptions described in Chapter 12.4.4 Economic considerations

14 Further work

The work presented in this thesis has explored several aspects related to load modelling and network calculations that are relevant to power system planning. The work has also revealed issues that still need to be addressed. Some tasks are proposed in the following:

Refining the method for probabilistic load modelling with the use of data from smart meters.
Perform studies concerning probabilistic load and generation modelling based on data from smart meters. How can the method proposed in Chapter 10 be improved and implemented in Network Information Systems and used for practical purposes by the distribution utilities? How can the problems associated with one-hour versus 15-minutes versus one-minute values best be handled?

Refining the method for probabilistic network calculations and implementing Monte Carlo simulations into network calculation systems.
Today's network calculations are deterministic. It must be possible to include individual distribution functions in every load and generation model. Monte Carlo simulations must be included in the network calculation systems in order to use these probabilistic models in network calculations.

Make recommendations and best practices that can be used as a basis for probabilistic modelling of new renewable distributed generations connected to the grid.
Here it could also be appropriate to look into the problems associated with hourly values versus 15 min values versus 1 min values.

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APPENDIX A – Demo case – calculation results

A.1 Simulation alternatives

Load flow calculations are done with Microsoft Excel and the probabilistic calculations ModelRisk – a Monte Carlo simulation risk analysis add-in for Microsoft Excel. Since Excel have no option for detailed simulation of a whole year of hourly values, only two load situations are simulated in this case:

- Winter load – in this case defined as Hour 11 in February.
- Summer load – in this case defined as Hour 11 in July.

Ten different simulation alternatives are investigated with four different load model alternatives. These are presented in Table A1-1 and Table A1-2.

Table A1-1 Simulation alternatives

#	Load situation	Demand response (DR)	Generation (DG)
1	Winter	-	0
2	Winter	Max 90 kW at School	0
3	Winter	Max 100 % on cables	0
4	Winter	-	50 kW
5	Winter	Max 90 kW at School	50 kW
6	Winter	Max 100 % on cables	50 kW
7	Summer	-	0
8	Summer	-	50 kW
9	Summer	Max 90 kW at School	50 kW
10	Summer	Max 100 % on cables	50 kW

Table A1-2 Load model alternatives

Load model	Peak load	Load variation curves	Distribution function
Deterministic 1	Calculated	Standard	-
Deterministic 2	Calculated	Individual	-
Deterministic 3	Metered	Individual	-
Probabilistic	Metered	Individual	Yes

The different load and generator models are described in the main report Chapter 11.2 and 11.4 respectively.

The following results are calculated for each of the ten alternatives:
- Loads
- Voltages at every node in the grid
- Branch currents in every transformer and cable in the grid
- Load on transformers and cables in percent of thermal limits
- Total active losses

For the probabilistic calculations, the 0, 50, 95 and 100 % values are presented.

A.2 Load models

Deterministic models
Deterministic load models are described in Chapter 0 in the main report. Three different models are described:

Table A 2-1 Deterministic load models

Model	Peak load	Load variation curves
Deterministic 1	Calculated	Standard
Deterministic 2	Calculated	Individual
Deterministic 3	Metered	Individual

Deterministic generation model is either max generation (installed capacity) or no generation.

Probabilistic models
Pareto distribution diagrams describing each load and generator in this demo case are presented in this chapter. The diagrams are calculated with the use of Monte Carlo simulations. Winter- and summer loads are presented, both without DR, in Chapter A.2.1 to Chapter A.2.7. The Pareto plots show load in kW on the x-axis and probability on the y-axis. The plot combines two curves – a histogram with probability for each value of load and an ascending cumulative plot with cumulative probability. Sliders (load values (x)) for cumulative probability 95,0% and 99,9% are marked in the plots.

For the generation in Chapter A.2.8, sliders for 0,1% and 5,0% that are marked. Since generation has the opposite sign in relation to loads, these sliders are used for the generation.

A.2.1 Workshop

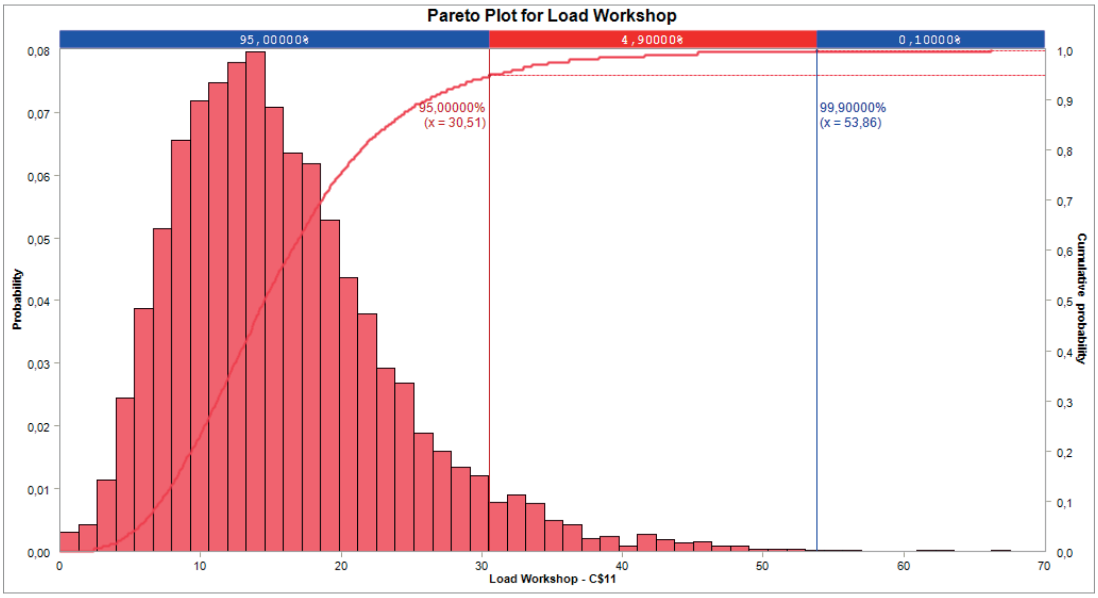


Figure A2-1 Load distribution - Workshop – Winter

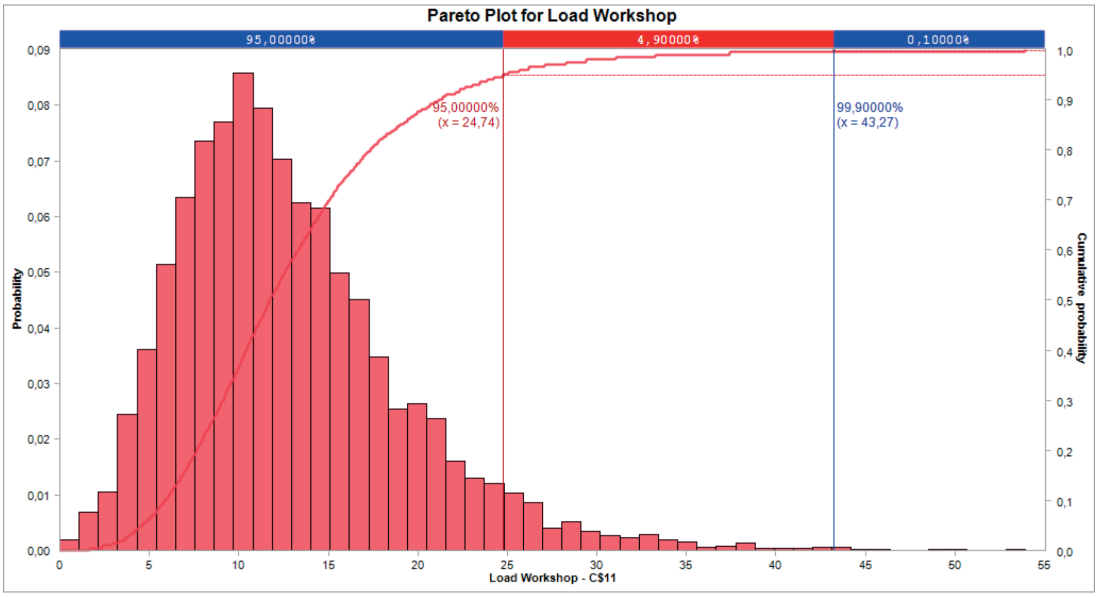


Figure A2-2 Load distribution – Workshop – Summer

Table A 2-2 Load Workshop (kW)

	Deterministic 1	Deterministic 2	Deterministic 3	Probabilistic Min	Probabilistic Mean	Probabilistic Max
Winter	19,5	18,9	29,7	0,0	15,8	66,2
summer	7,8	15,0	23,6	0,0	12,8	53,9

A.2.2 Grocerystore

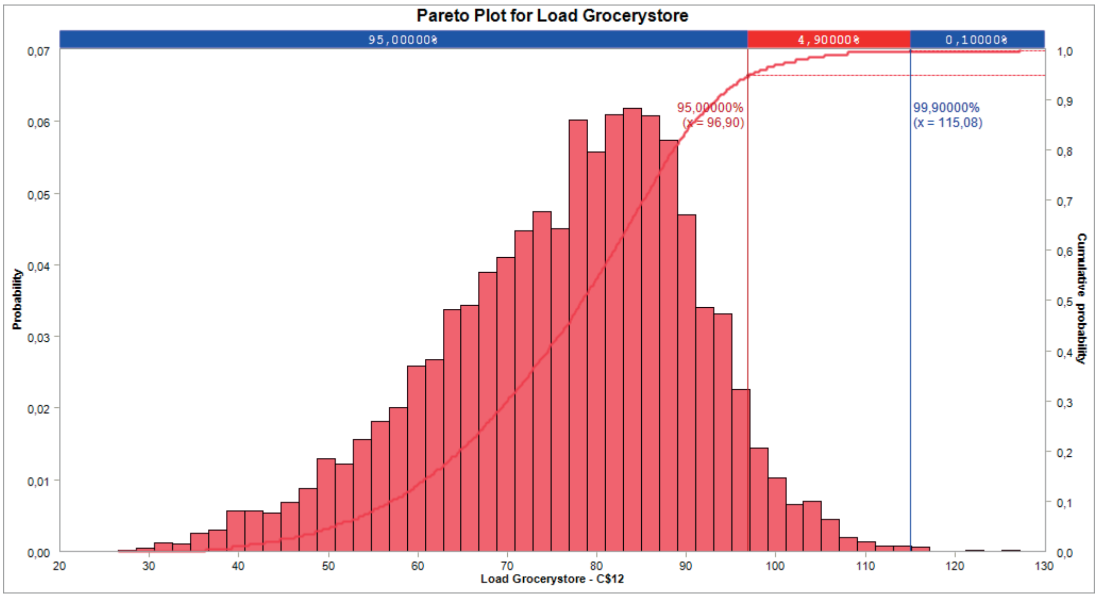


Figure A2-3 Load distribution - Grocerystore – Winter

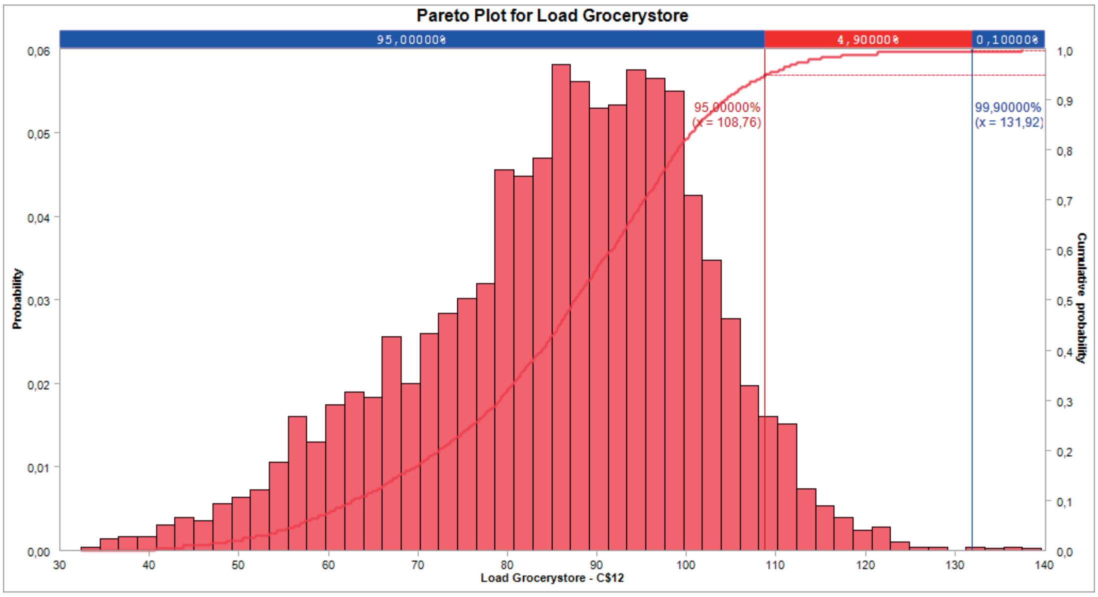


Figure A2-4 Load distribution – Grocerystore – Summer

Table A 2-3 Load Grocerystore (kW)

	Deterministic 1	Deterministic 2	Deterministic 3	Probabilistic Min	Probabilistic Mean	Probabilistic Max
Winter	144,7	129,2	103,8	26,6	76,5	127,3
summer	57,9	144,7	116,2	32,4	85,7	137,6

A.2.3 School

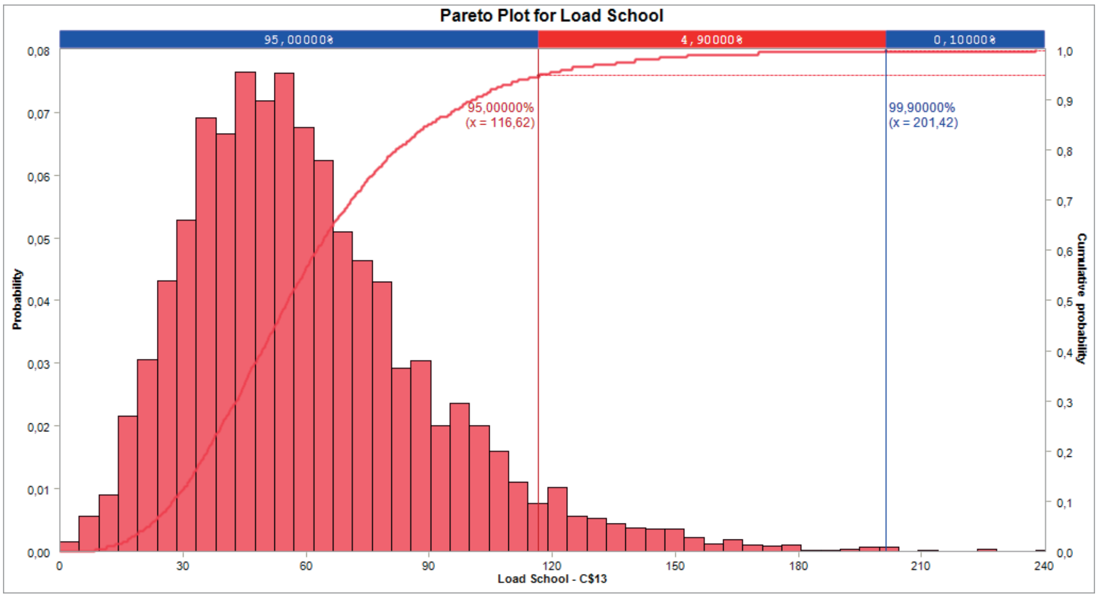


Figure A2-5 Load distribution - School – Winter

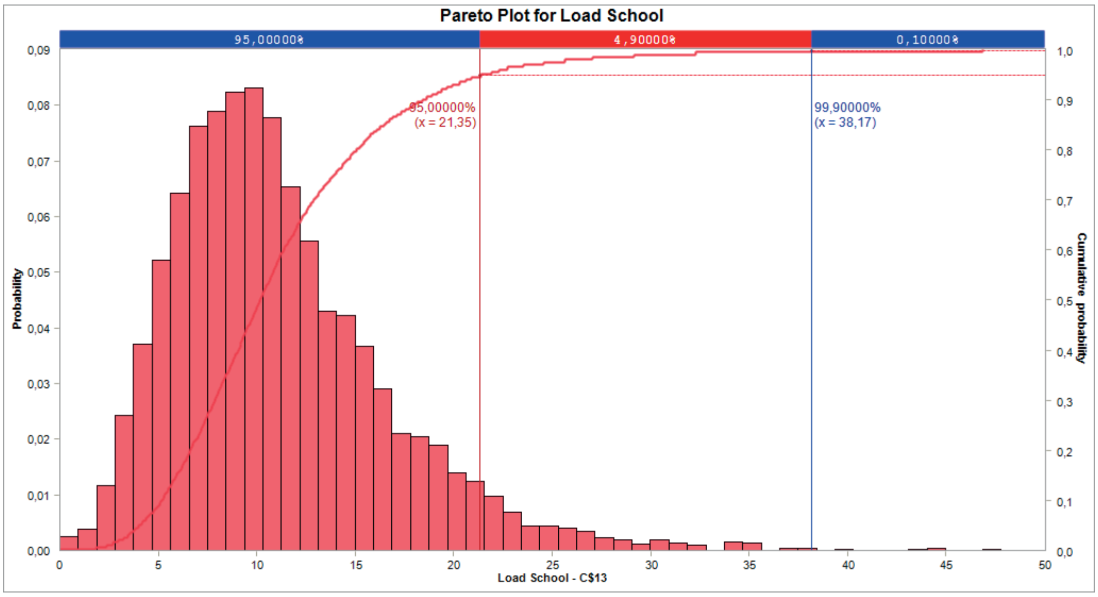


Figure A2-6 Load distribution – School – Summer

Table A 2-4 Load School (kW)

	Deterministic 1	Deterministic 2	Deterministic 3	Probabilistic Min	Probabilistic Mean	Probabilistic Max
Winter	49,0	49,5	136,9	0,0	60,5	237,8
summer	19,6	8,9	24,6	0,0	11,1	46,9

A.2.4 Farm

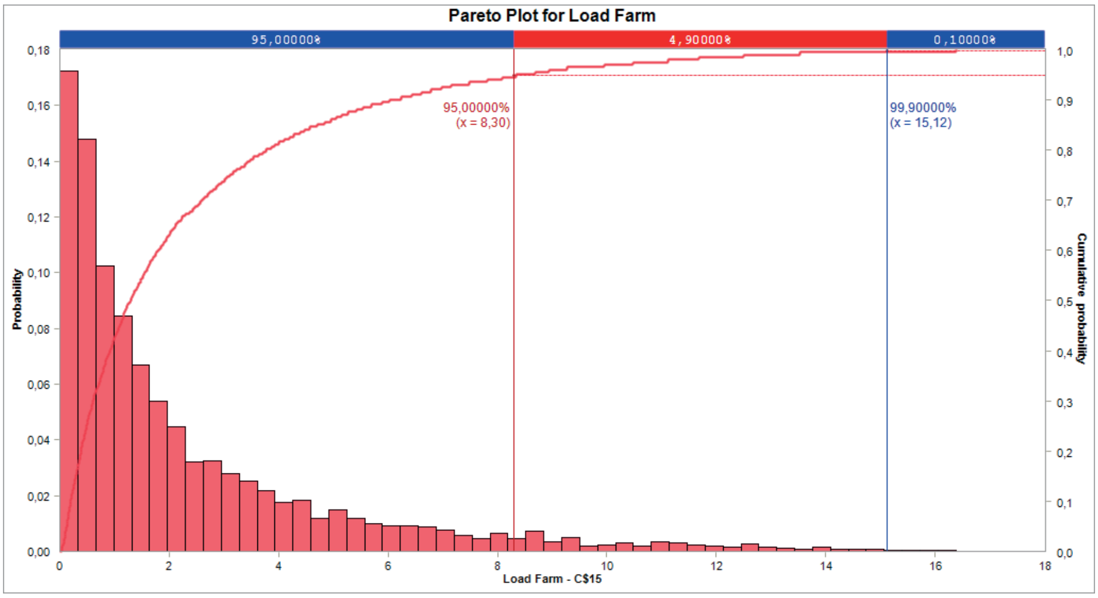


Figure A2-7 Load distribution - Farm – Winter

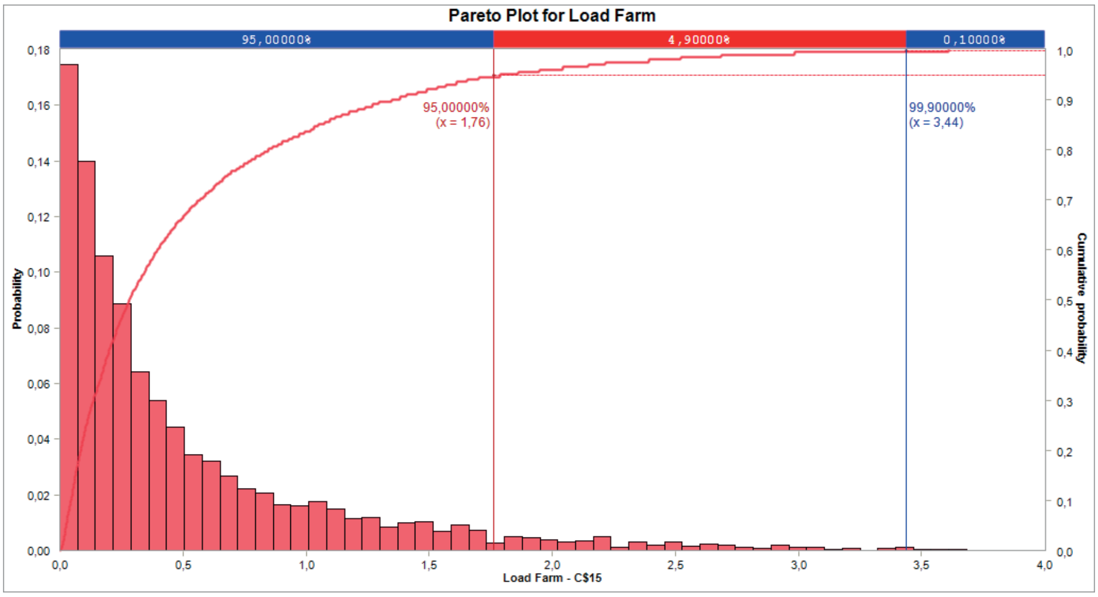


Figure A2-8 Load distribution – Farm – Summer

Table A 2-5 Load Farm (kW)

	Deterministic 1	Deterministic 2	Deterministic 3	Probabilistic Min	Probabilistic Mean	Probabilistic Max
Winter	2,1	1,2	15,6	0,0	2,3	16,4
summer	0,8	0,3	3,3	0,0	0,5	3,6

A.2.5 House #1

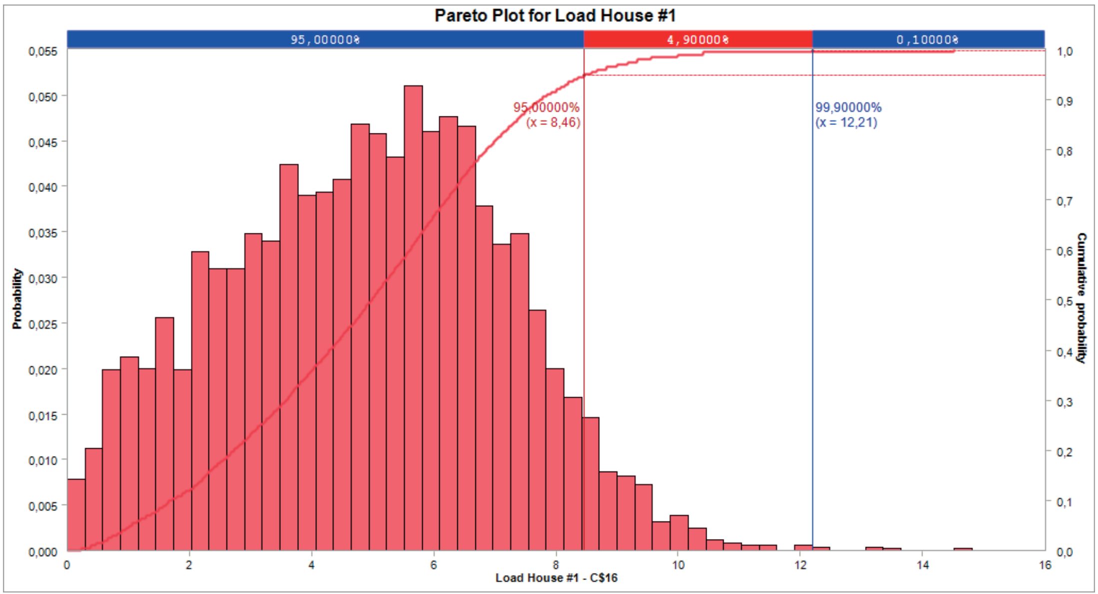


Figure A2-9 Load distribution – House #1 – Winter

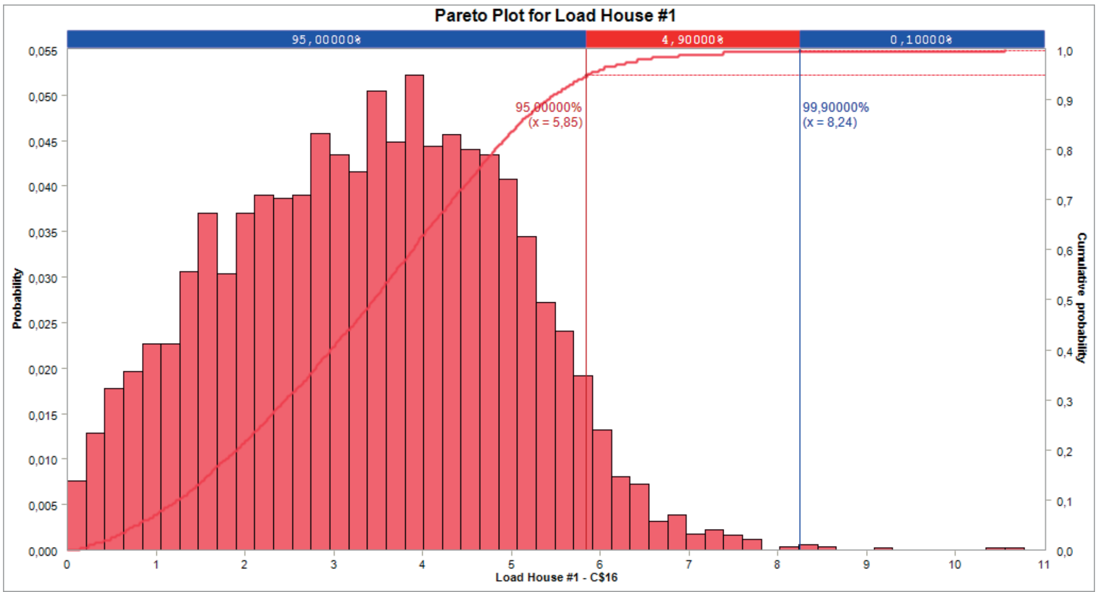


Figure A2-10 Load distribution – House #1 – Summer

Table A 2-6 Load House #1 (kW)

	Deterministic 1	Deterministic 2	Deterministic 3	Probabilistic Min	Probabilistic Mean	Probabilistic Max
Winter	8,3	7,0	10,2	0,0	4,9	14,5
summer	3,3	4,9	7,1	0,0	3,4	10,6

A.2.6 House #2

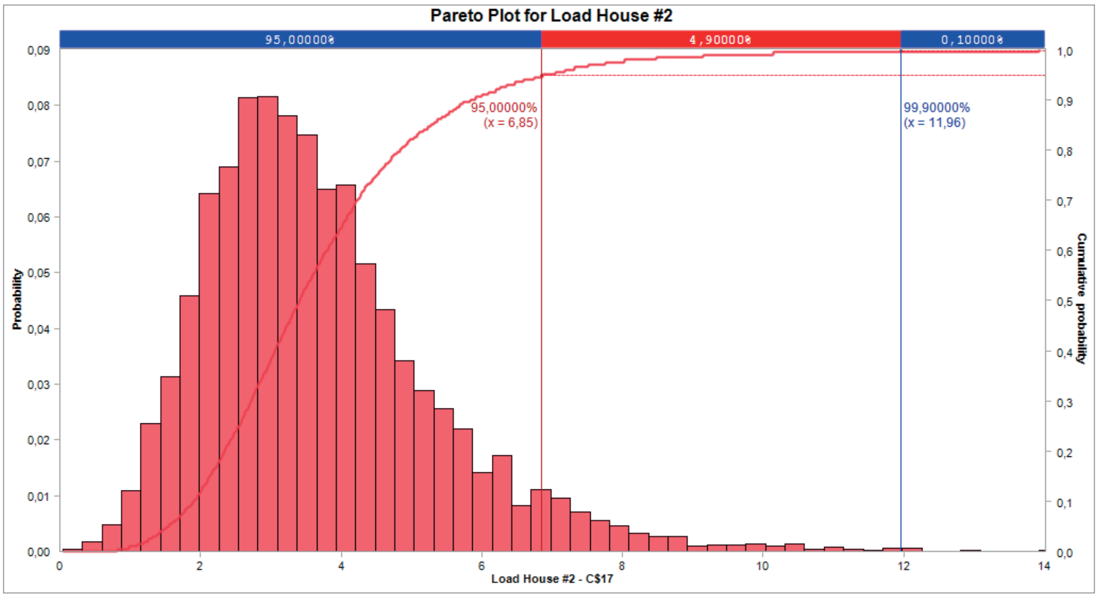


Figure A2-11 Load distribution – House #2 – Winter

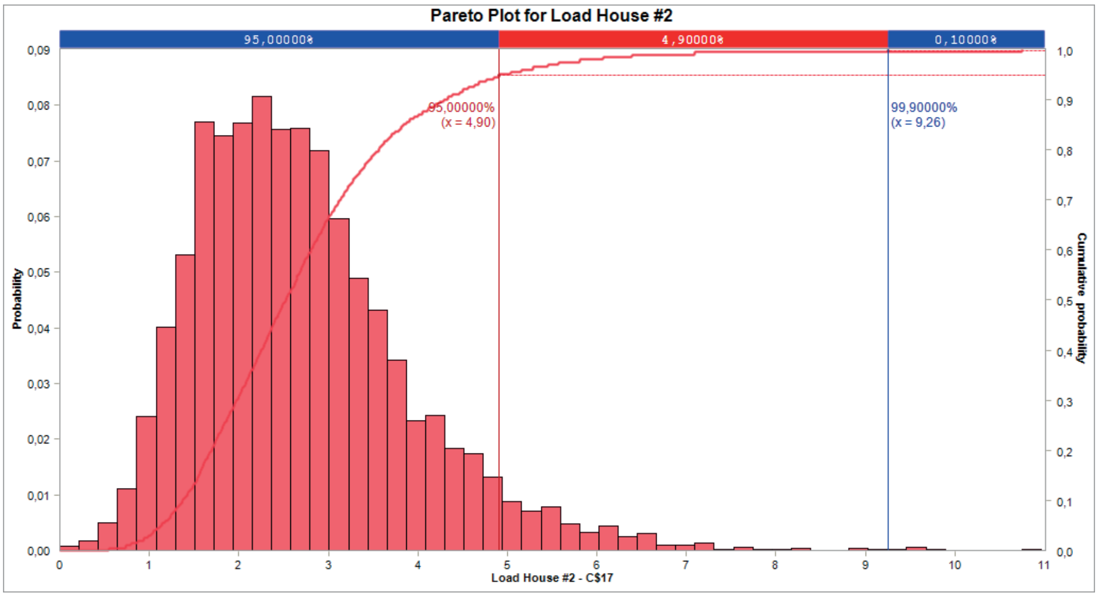


Figure A2-12 Load distribution – House #2 – Summer

Table A 2-7 Load House #2 (kW)

	Deterministic 1	Deterministic 2	Deterministic 3	Probabilistic Min	Probabilistic Mean	Probabilistic Max
Winter	4,8	4,4	7,7	0,0	3,7	13,9
summer	1,9	3,2	5,6	0,0	2,7	10,8

A.2.7 House #3

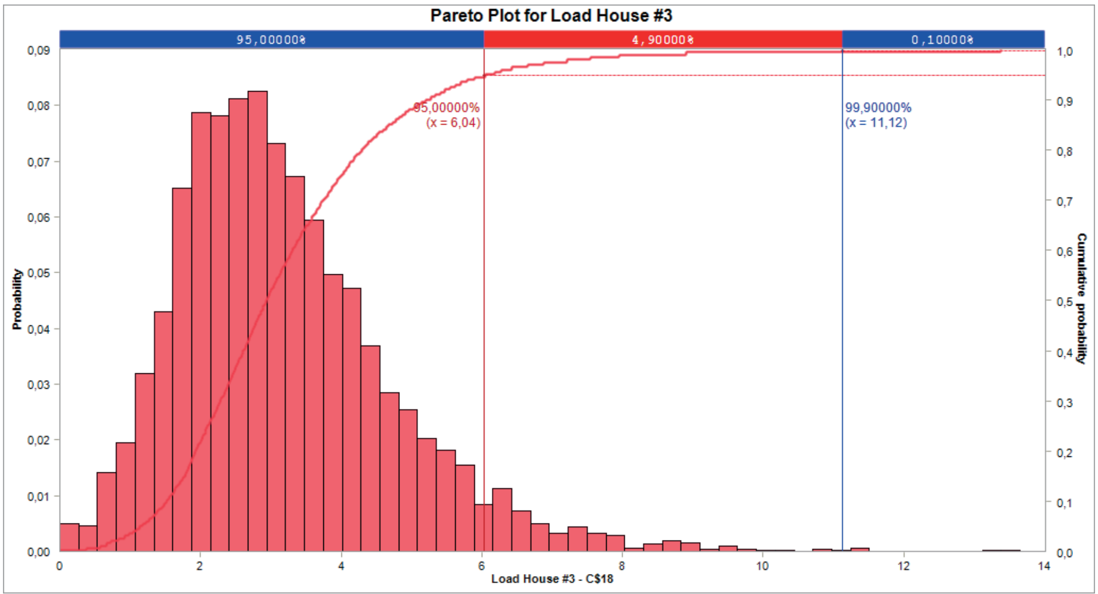


Figure A2-13 Load distribution – House #3 – Winter

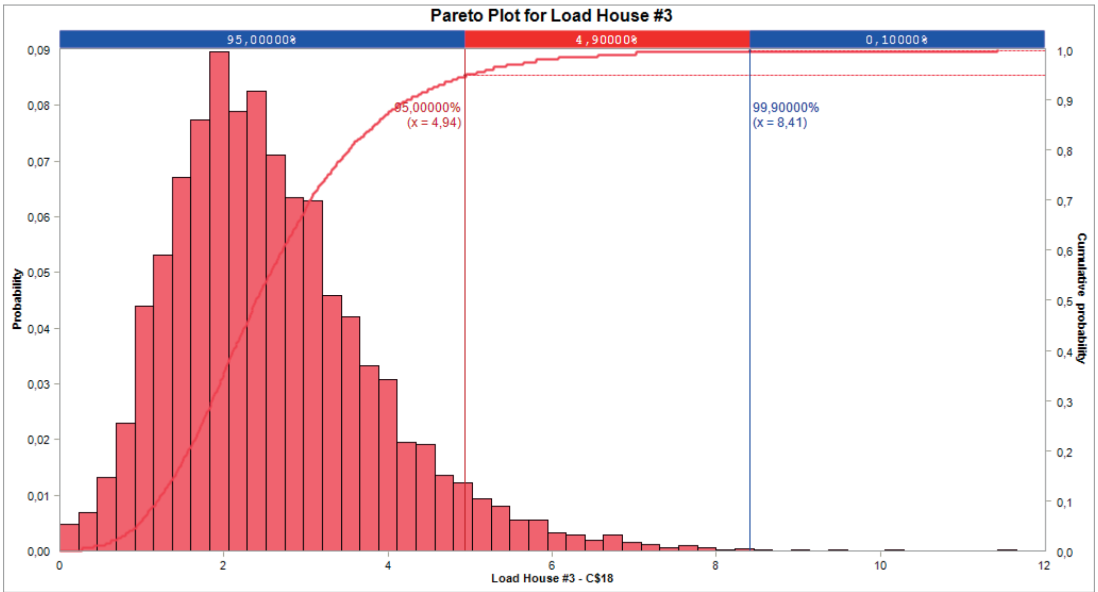


Figure A2-14 Load distribution – House #3 – Summer

Table A 2-8 Load House #3 (kW)

	Deterministic 1	Deterministic 2	Deterministic 3	Probabilistic Min	Probabilistic Mean	Probabilistic Max
Winter	5,2	4,1	6,9	0,0	3,2	13,4
summer	2,1	3,3	5,6	0,0	2,6	11,4

A.2.8 Generation (photovoltaics)

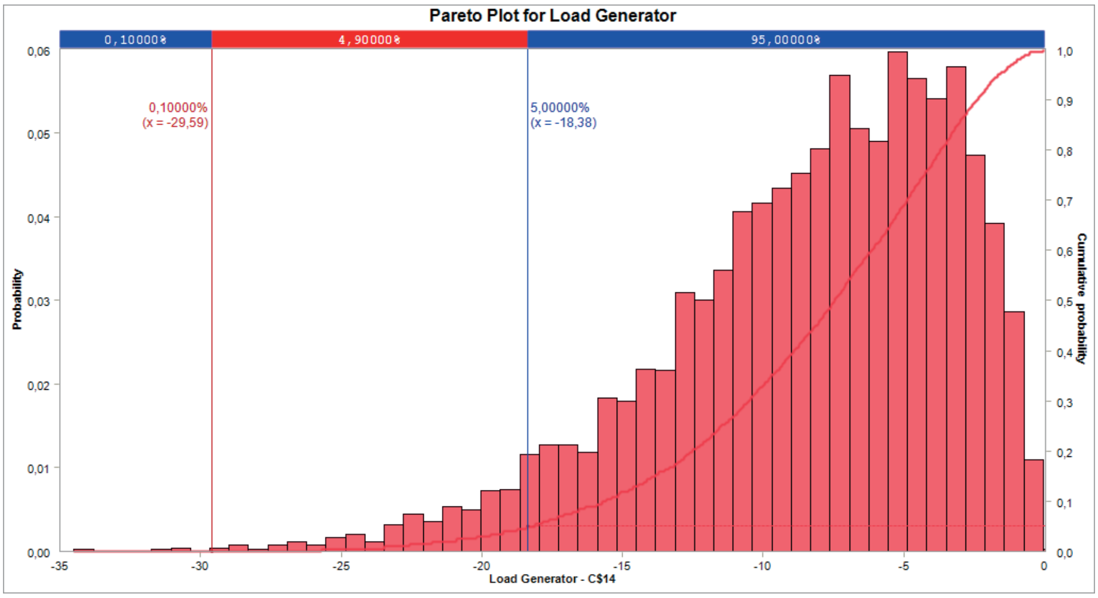


Figure A2-15 Generation distribution – Photovoltaics – Winter

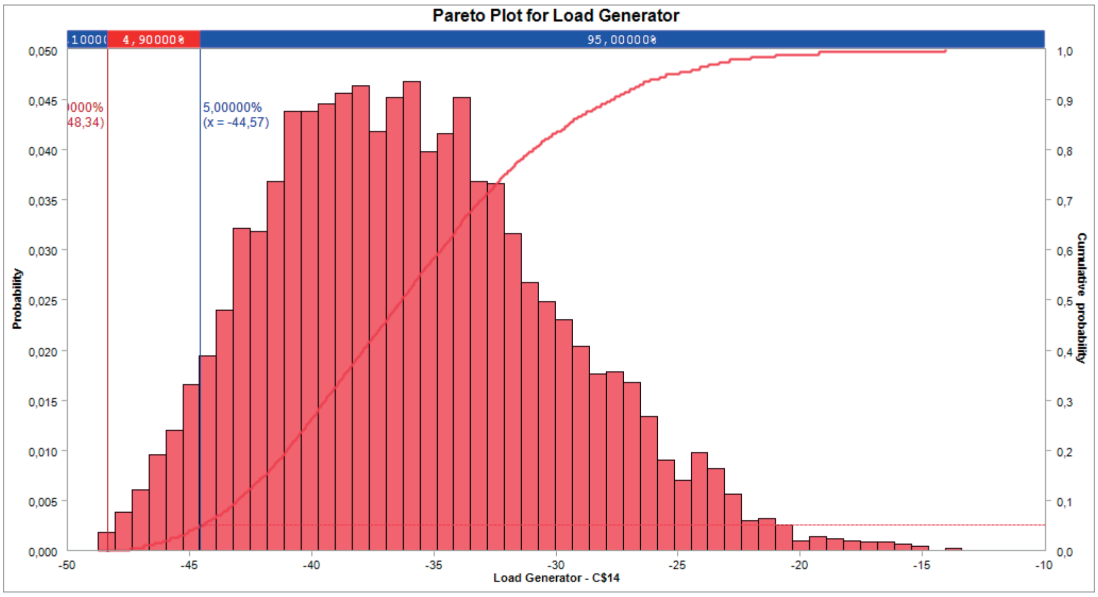


Figure A2-16 Generation distribution – Photovoltaics – Summer

Table A 2-9 Generation (kW)

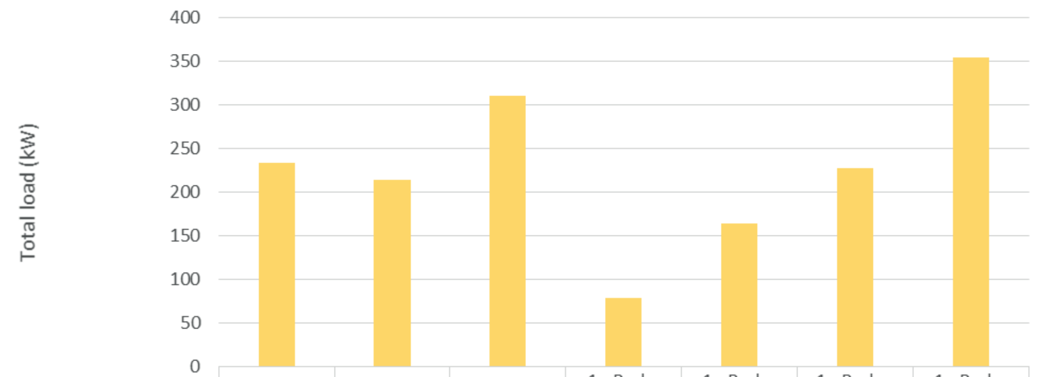
	Deterministic 1	Deterministic 2	Deterministic 3	Probabilistic Min	Probabilistic Mean	Probabilistic Max
Winter	-50	-50	-50	-0,0	-8,4	-34,5
summer	-50	-50	-50	-14,1	-35,9	-48,7

A.3 Simulation results

Ten different simulations are performed according to the description given in Chapter A.1. Aggregated load, voltages, branch currents, branch loading in percent and total active losses are presented in this chapter A.3.

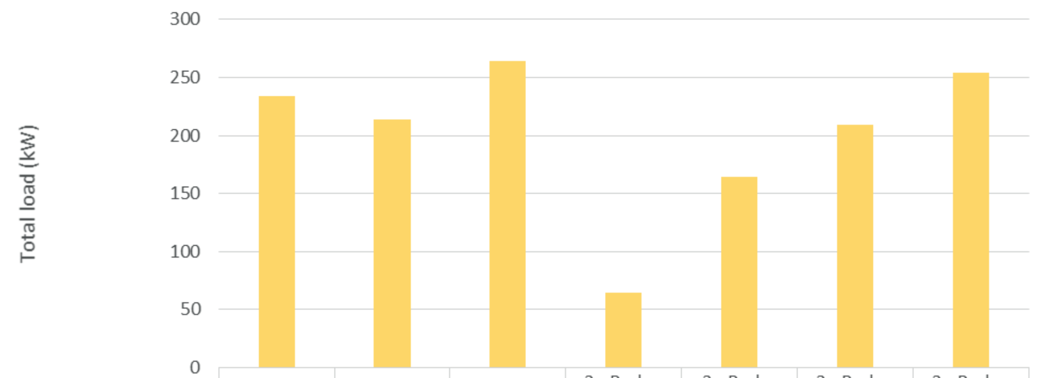
A.3.1 Aggregated load and generation

Aggregated load and generation is the resulting power supplied through the distribution transformer, i.e. aggregation of every load and generator in the grid.



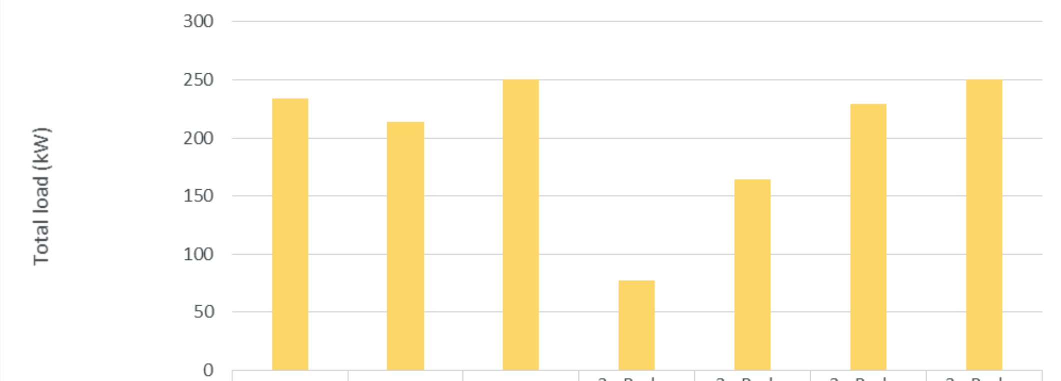
	1 - Det. #1	1 - Det. #2	1 - Det. #3	1 - Prob., 0%	1 - Prob., 50%	1 - Prob., 95%	1 - Prob., 100%
Generation	0	0	0	0	0	0	0
Load and generation	234	214	311	79	164	227	355

Figure A3-1 Simulation 1 - Winter load



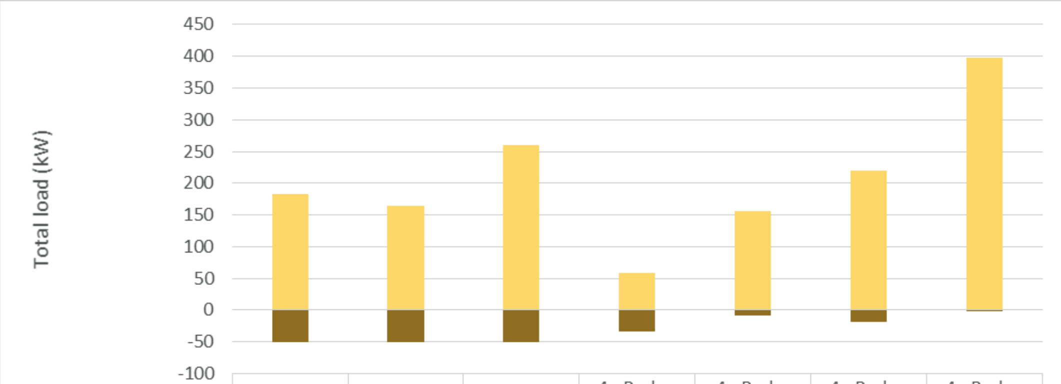
	2 - Det. #1	2 - Det. #2	2 - Det. #3	2 - Prob., 0%	2 - Prob., 50%	2 - Prob., 95%	2 - Prob., 100%
Generation	0	0	0	0	0	0	0
Load and generation	234	214	264	65	164	209	254

Figure A3-2 Simulation 2 - Winter load with DR (max 90 kW at School)



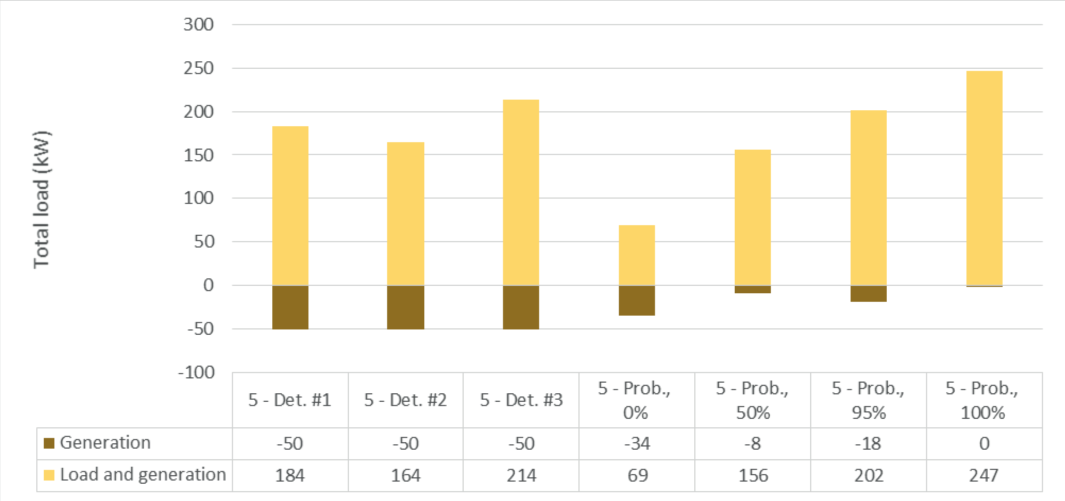
	3 - Det. #1	3 - Det. #2	3 - Det. #3	3 - Prob., 0%	3 - Prob., 50%	3 - Prob., 95%	3 - Prob., 100%
Generation	0	0	0	0	0	0	0
Load and generation	234	214	250	77	164	230	250

Figure A3-3 Simulation 3 - Winter load with DR (max 100% in Cable 1)



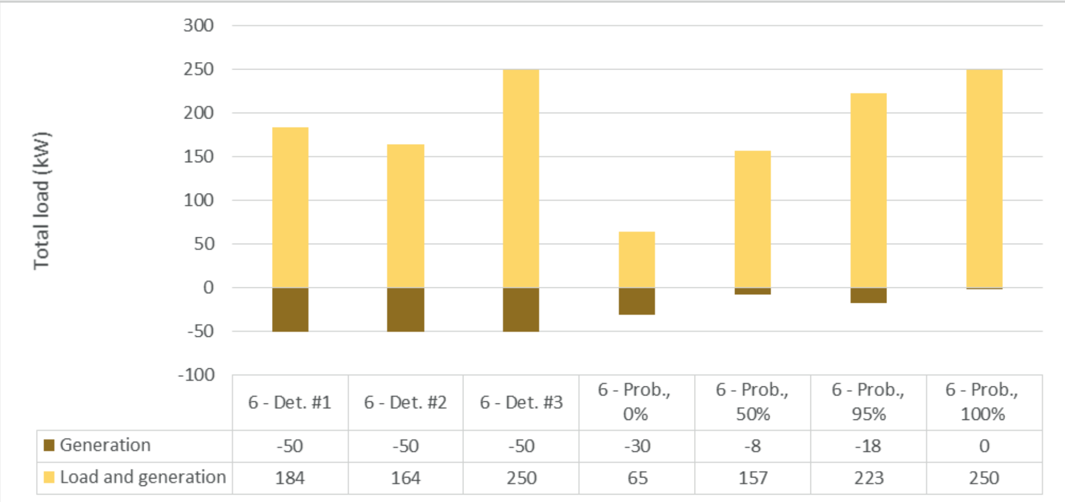
	4 - Det. #1	4 - Det. #2	4 - Det. #3	4 - Prob., 0%	4 - Prob., 50%	4 - Prob., 95%	4 - Prob., 100%
Generation	-50	-50	-50	-34	-8	-18	0
Load and generation	184	164	261	59	155	220	397

Figure A3-4 Simulation 4 - Winter load with DG (50 kW photovoltaics)



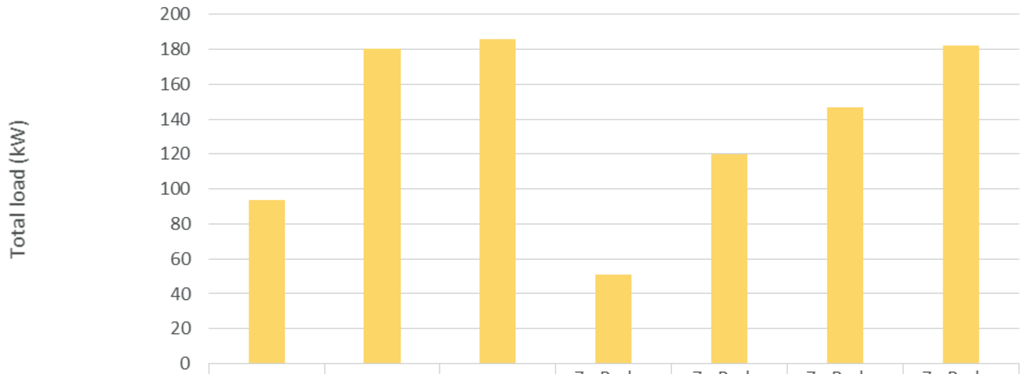
	5 - Det. #1	5 - Det. #2	5 - Det. #3	5 - Prob., 0%	5 - Prob., 50%	5 - Prob., 95%	5 - Prob., 100%
Generation	-50	-50	-50	-34	-8	-18	0
Load and generation	184	164	214	69	156	202	247

Figure A3-5 Simulation 5 - Winter load with DG (50 kW photovoltaics) and DR (max 90 kW at School)



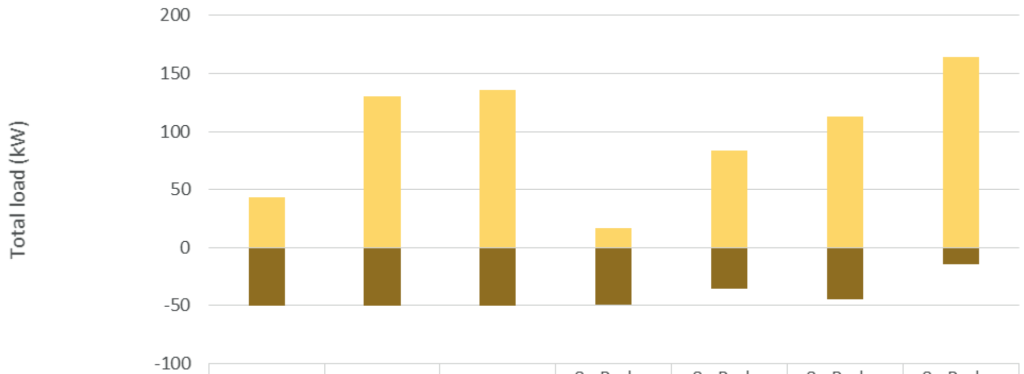
	6 - Det. #1	6 - Det. #2	6 - Det. #3	6 - Prob., 0%	6 - Prob., 50%	6 - Prob., 95%	6 - Prob., 100%
Generation	-50	-50	-50	-30	-8	-18	0
Load and generation	184	164	250	65	157	223	250

Figure A3-6 Simulation 6 - Winter load with DG (50 kW photovoltaics) and DR (max 100% in Cable 1)



	7 - Det., #1	7 - Det., #2	7 - Det., #3	7 - Prob., 0%	7 - Prob., 50%	7 - Prob., 95%	7 - Prob., 100%
Generation	0	0	0	0	0	0	0
Load and generation	93	180	186	51	120	147	182

Figure A3-7 Simulation 7 – Summer load



	8 - Det. #1	8 - Det. #2	8 - Det. #3	8 - Prob., 0%	8 - Prob., 50%	8 - Prob., 95%	8 - Prob., 100%
Generation	-50	-50	-50	-49	-36	-45	-14
Load and generation	43	130	136	16	84	113	164

Figure A3-8 Simulation 8 – Summer load with DG (50 kW photovoltaics)

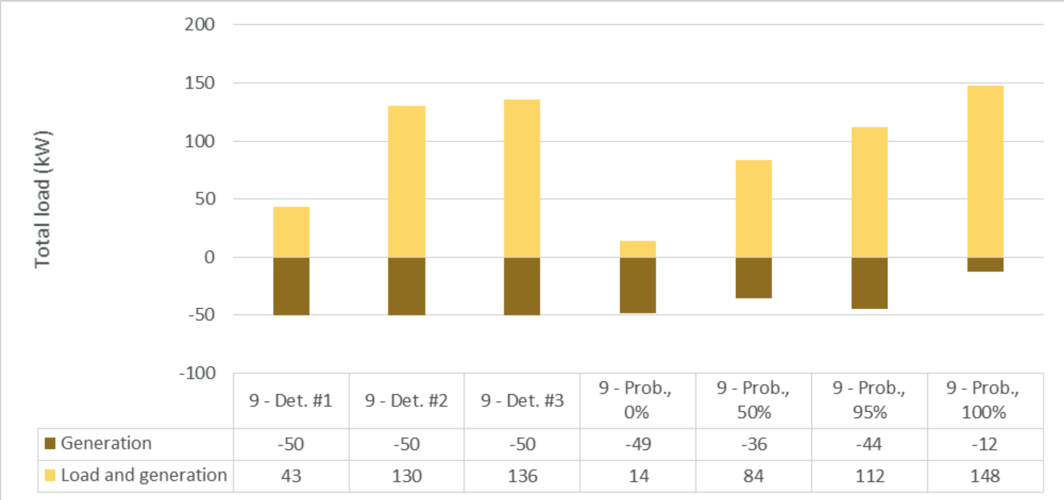


Figure A3-9 Simulation 9 – Summer load with DG (50 kW photovoltaics) and DR (max 90 kW at School)

According to *Figure A2-6 Load distribution – School – Summer* will the load at School never be as high as 90 kW in Summer. This means this DR never will come to action in summer, and Figure A3-9 will be equal to Figure A3-8. There might be some difference between the corresponding probabilistic values in these two figures because they are based on two different Monte Carlo simulations on the same model.

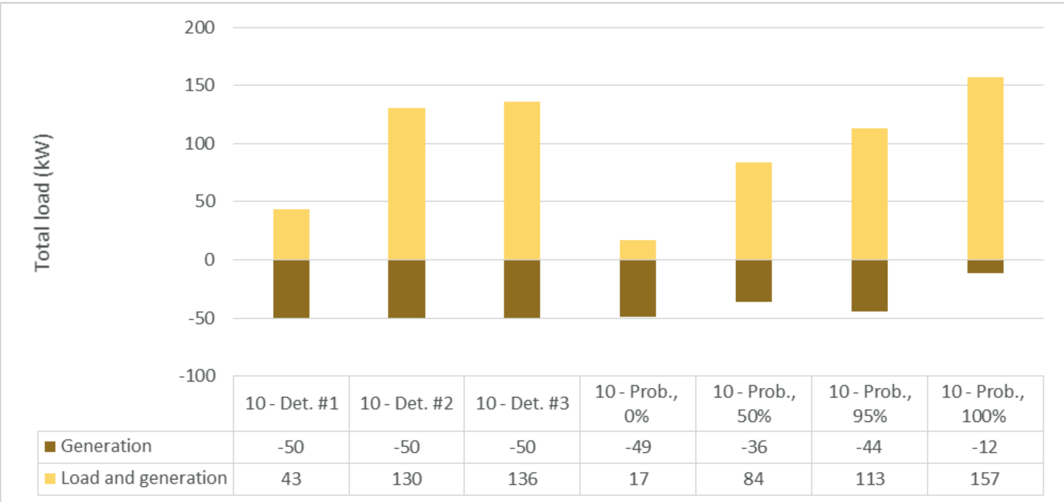


Figure A3-10 Simulation 10 – Summer load with DG (50 kW photovoltaics) and DR (max 100% in Cable 1)

According to Figure A3-11 will the load in Cable 1 in summer with DG never be near 100 % of the thermal limit for the cable. This means that this DR never will come to action in summer, and Figure A3-10 will be equal to Figure A3-8 and Figure A3-9.

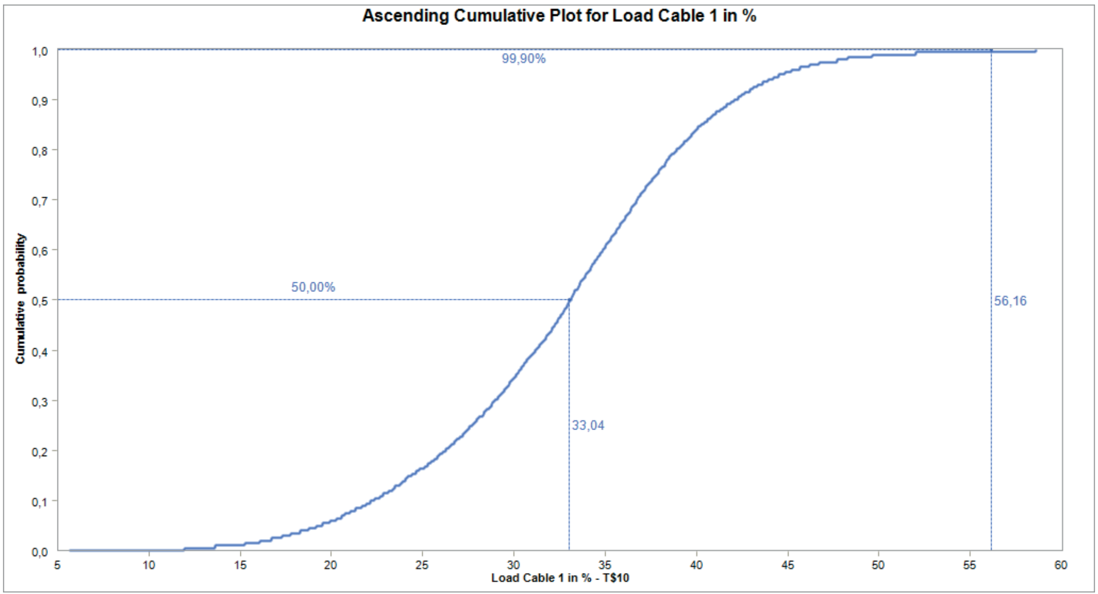


Figure A3-11 Simulation 8 - Summer load with DG (50 kW photovoltaics) - Load Cable 1 in %

A.3.2 Voltages

Voltages are calculated for every node in the model. The voltage at the feeding point is fixed at 400 V.

It is of interest to find out if voltages in the grid are within the limits or not. In this case it is interesting to look at the voltage at the outermost end of the grid, i.e. at House #3. The minimum voltage at House #3 according to the probabilistic model is almost equal to the voltage according to the deterministic model #3. Figure A3-20 presents the result from a probabilistic calculation of voltage at House #3.

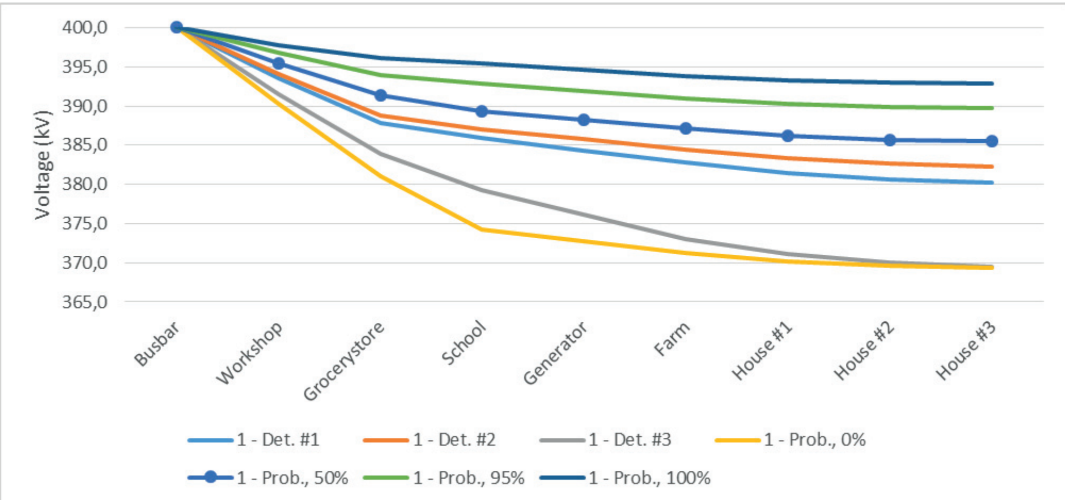


Figure A3-12 Voltage - Simulation 1 – Winter load

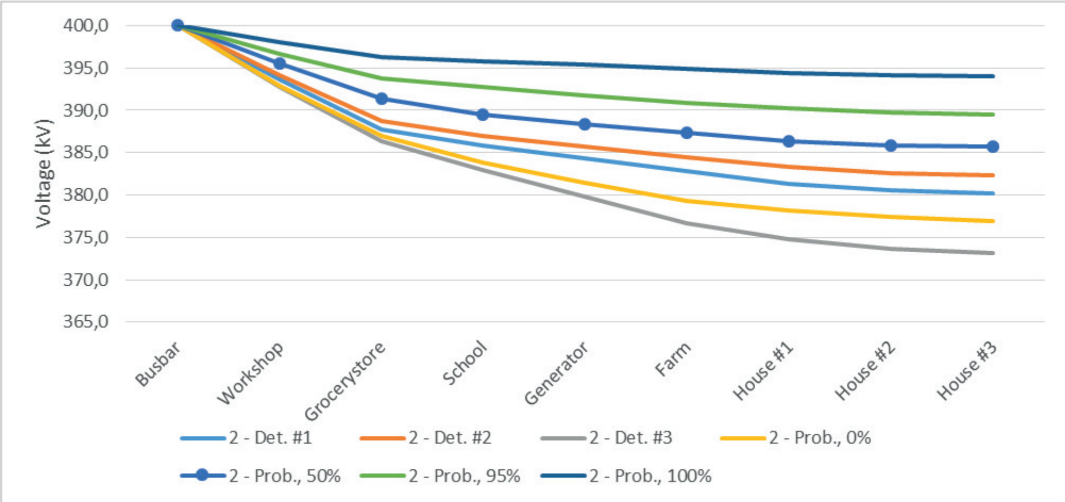


Figure A3-13 Voltage - Simulation 2 – Winter load and DR (max 90 kW at School)

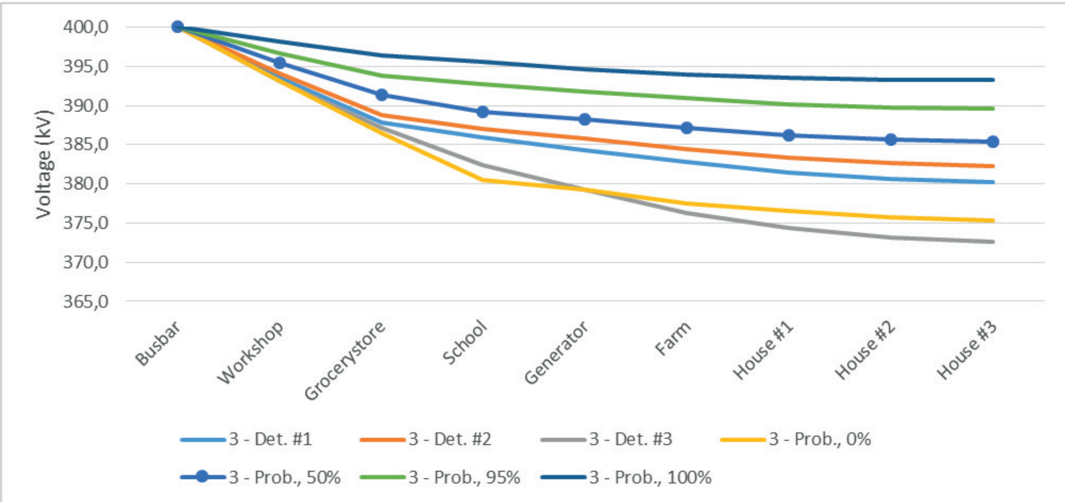


Figure A3-14 Voltage - Simulation 3 – Winter load and DR (max 100% in Cable 1)

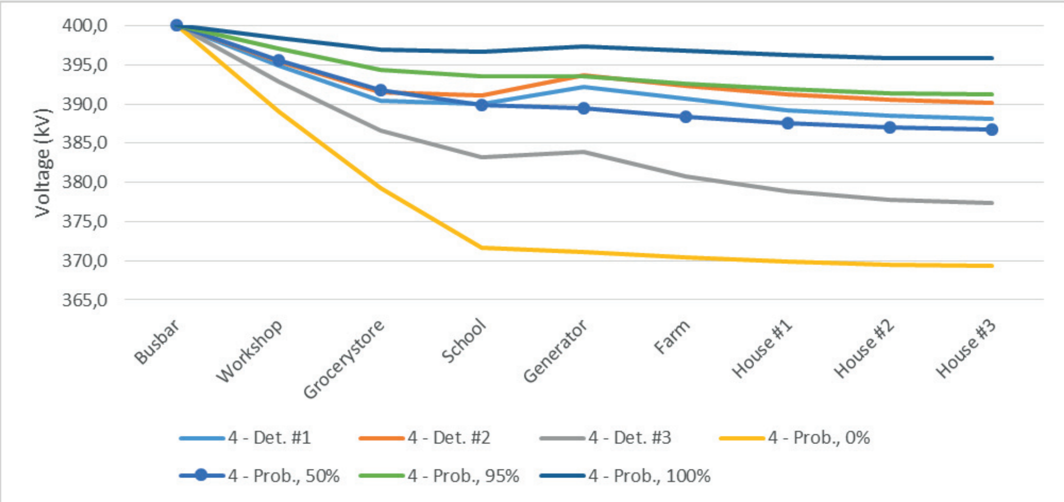


Figure A3-15 Voltage - Simulation 4 – Winter load and DG (50 kW photovoltaics)

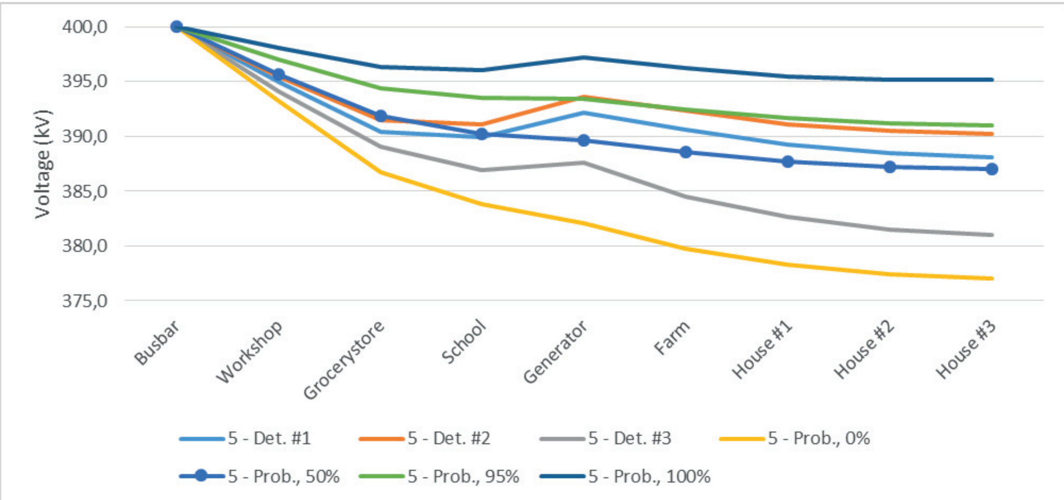


Figure A3-16 Voltage - Simulation 5 – Winter load and DG (50 kW photovoltaics) and DR (max 90 kW at School)

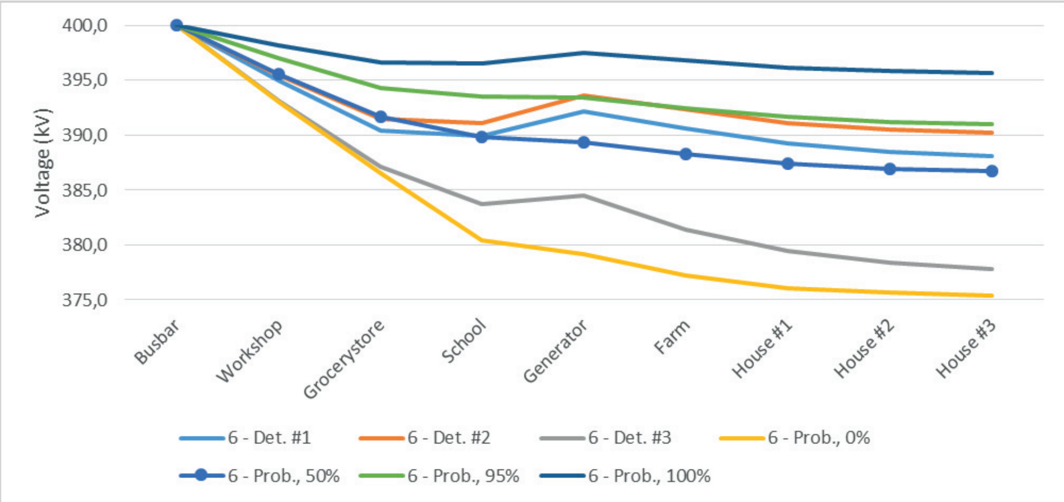


Figure A3-17 Voltage - Simulation 6 – Winter load and DG (50 kW photovoltaics) and DR (max 100% in Cable1)

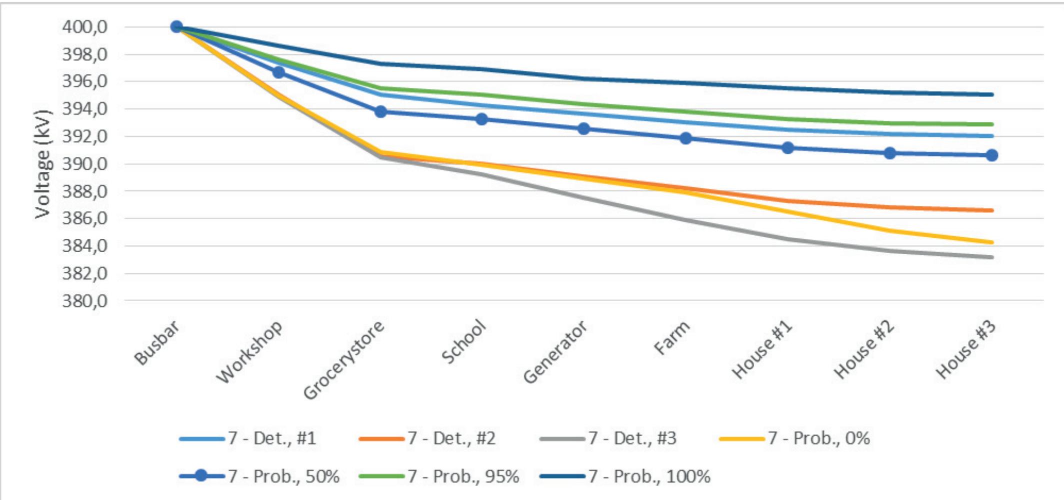


Figure A3-18 Voltage - Simulation 7 – Summer load

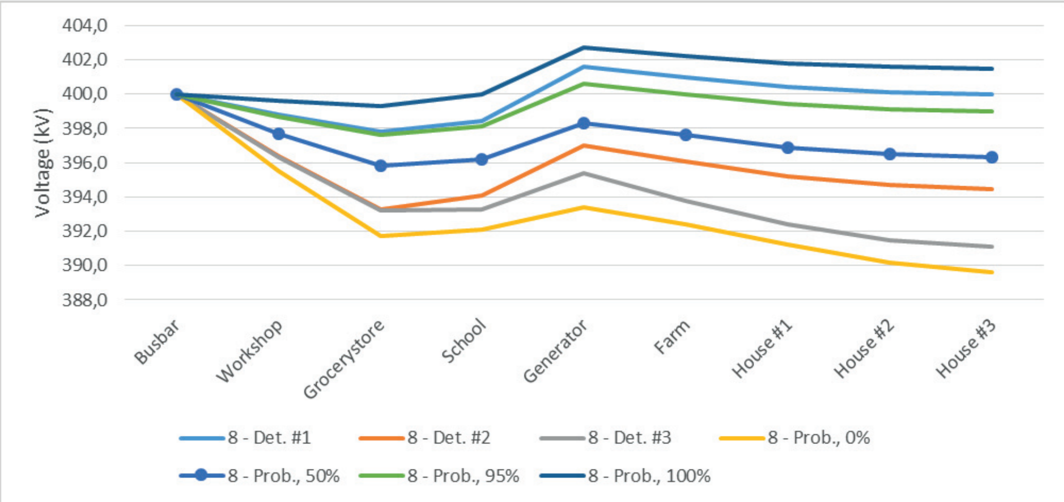


Figure A3-19 Voltage - Simulation 8 – Summer load and DG (50 kW photovoltaics)

According to the comments given earlier, the two alternative DR's in this model will never come to action during summer. This means that Figure A3-19 is valid for simulation alternatives 9 and 10 (summer load with DR) as well. Figure A3-20 shows a detailed plot for the voltage at the outermost point in the grid (at House #3) in the situation that gives lowest voltage at the end (Simulation 1 – Winter load).

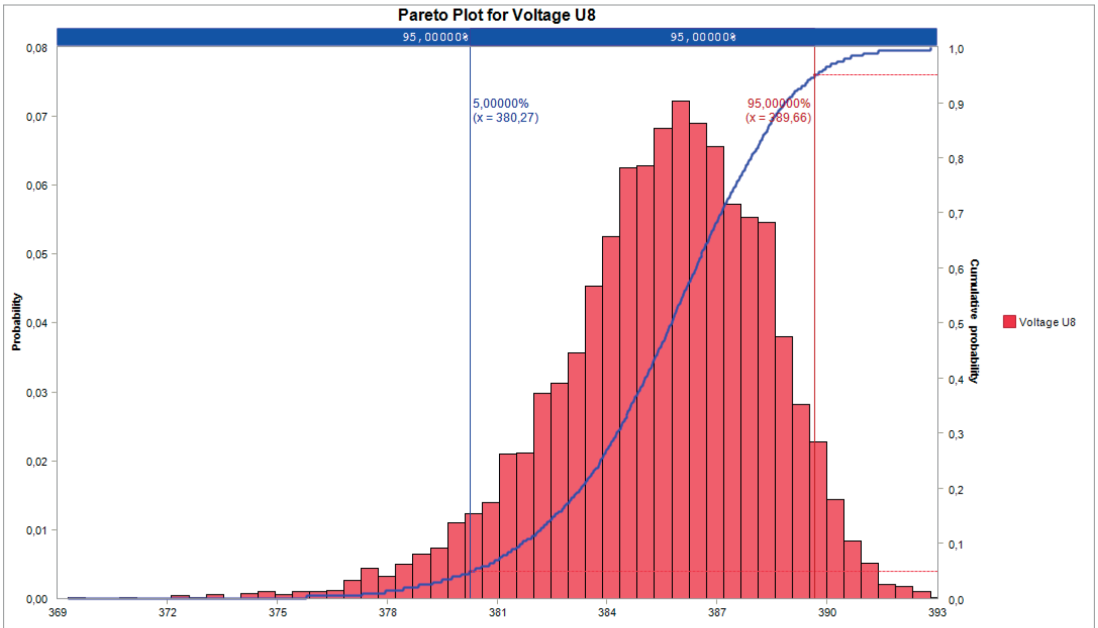


Figure A3-20 Voltage House #3 - Simulation 1 - Winter load – Probabilistic model

The minimum value is 369 V and the maximum is 393 V. The probabilistic calculation also tells us that there is only a probability of 5 % that the voltage in this node will be lower than 380 V.

A.3.3 Branch currents and loading

Currents through transformer and cables and the relationship between these currents and the corresponding thermal load limit for transformer and cables are calculated.

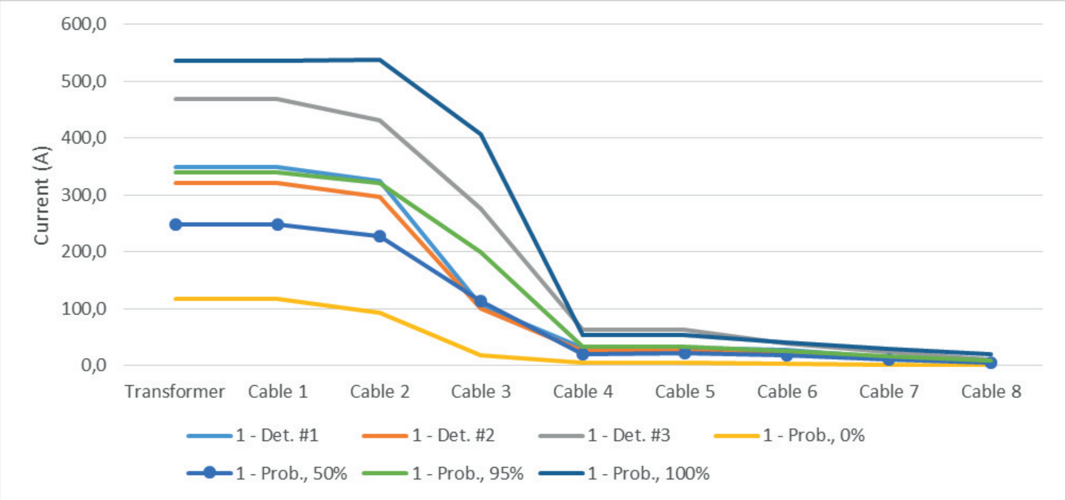


Figure A3-21 Branch currents - Simulation 1 - Winter load

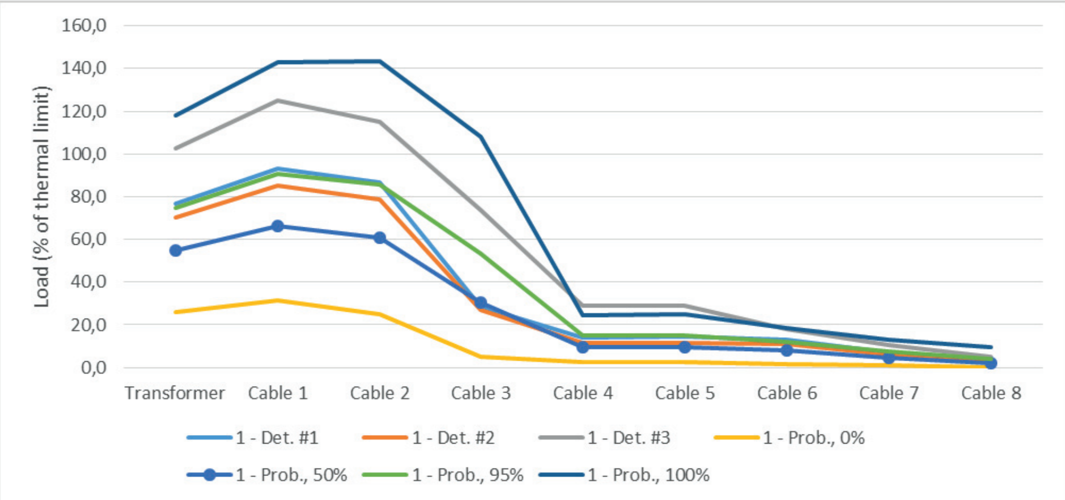


Figure A3-22 Load on transformer and cables - Simulation 1 - Winter load

According to Figure A3-22, the transformer and the three first cables might be overloaded. Both the deterministic model #3 and the probabilistic model results in more than 100 % load in these parts of the grid. The deterministic models (# 1 and 2) based on calculated peak load underestimates the load does not indicate probability of overloaded transformer and cables. In this case, an overload of Cable 1 is most likely to happen.

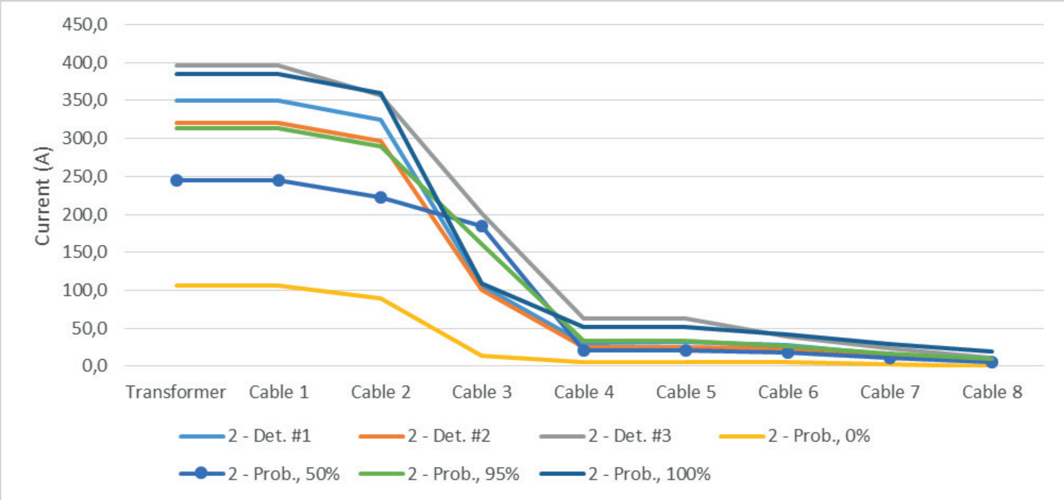


Figure A3-23 Branch currents - Simulation 2 - Winter load with DR (max 90 kW at School)

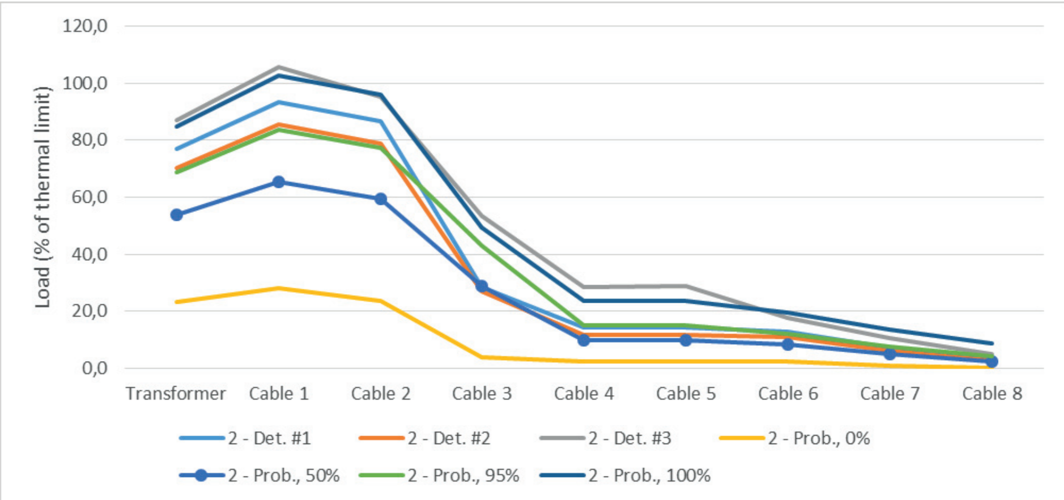


Figure A3-24 Load on transformer and cables - Simulation 2 - Winter load with DR (max 90 kW at School)

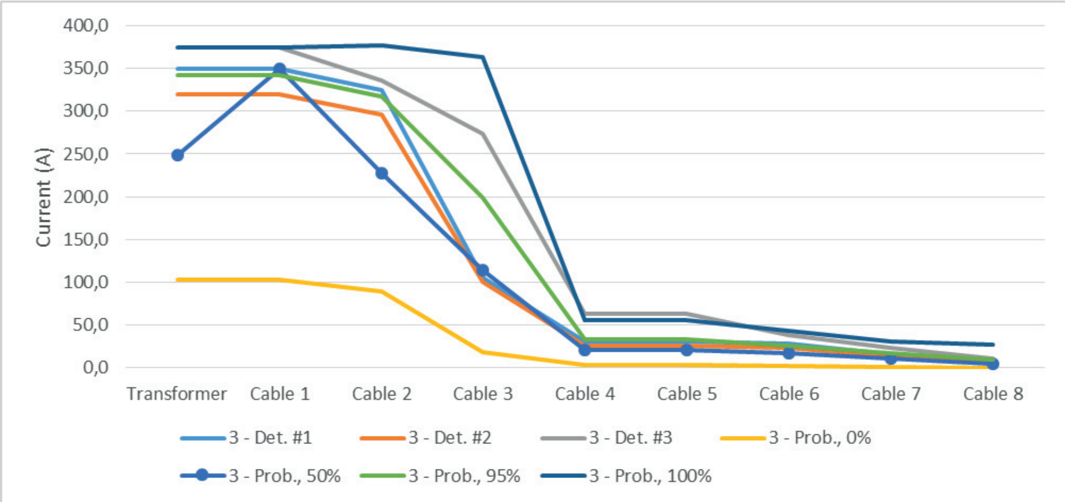


Figure A3-25 Branch currents - Simulation 3 - Winter load with DR (max 100% in Cable 1)

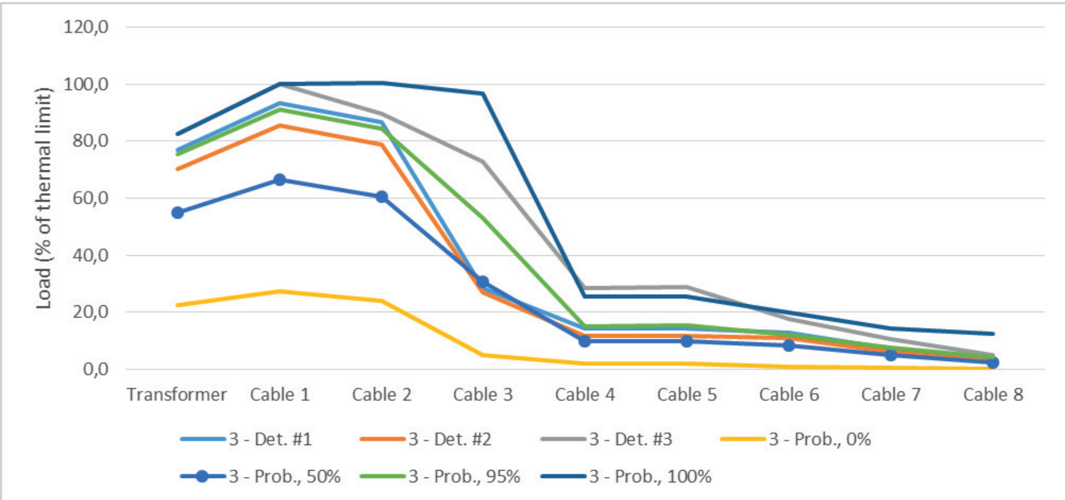


Figure A3-26 Load on transformer and cables - Simulation 3 - Winter load with DR (max 100% in Cable 1)

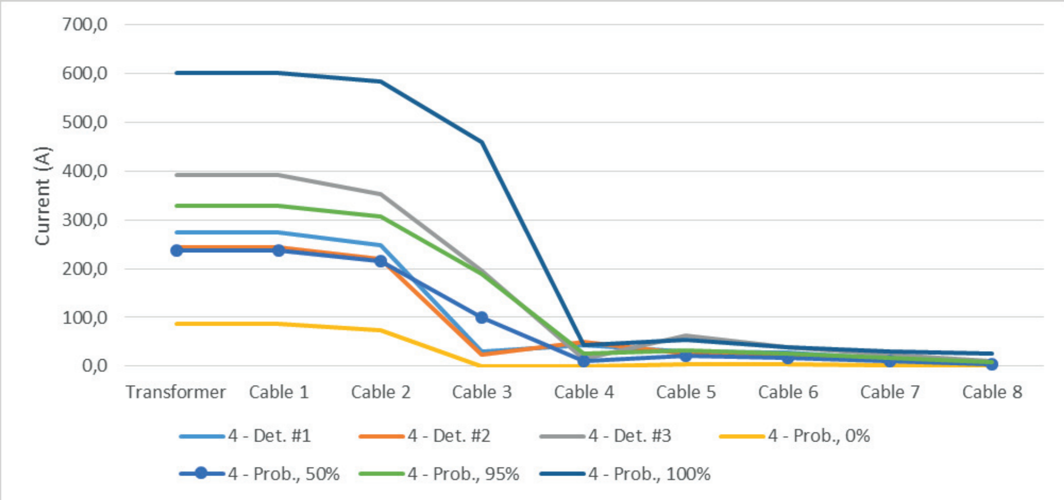


Figure A3-27 Branch currents - Simulation 4 - Winter load with DG (50 kW photovoltaics)

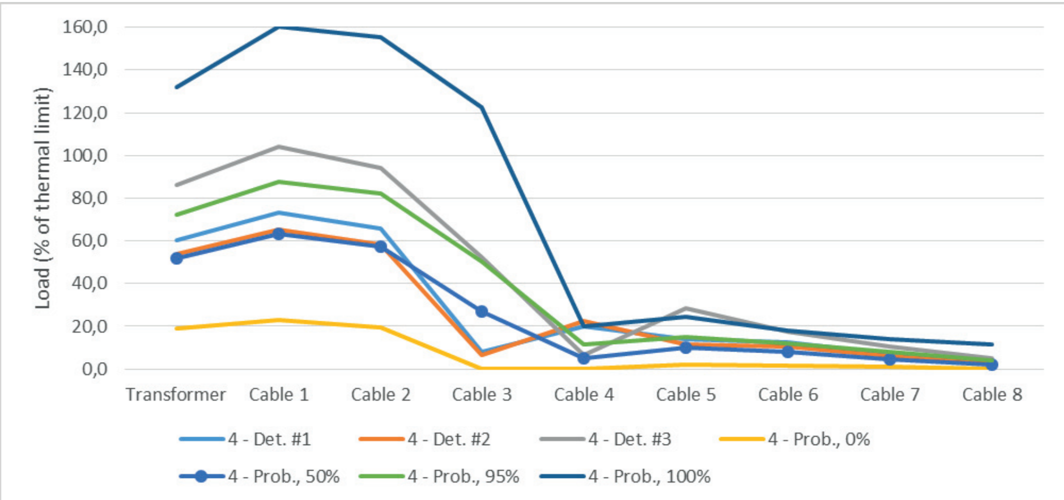


Figure A3-28 Load on transformer and cables - Simulation 4 - Winter load with DG (50 kW photovoltaics)

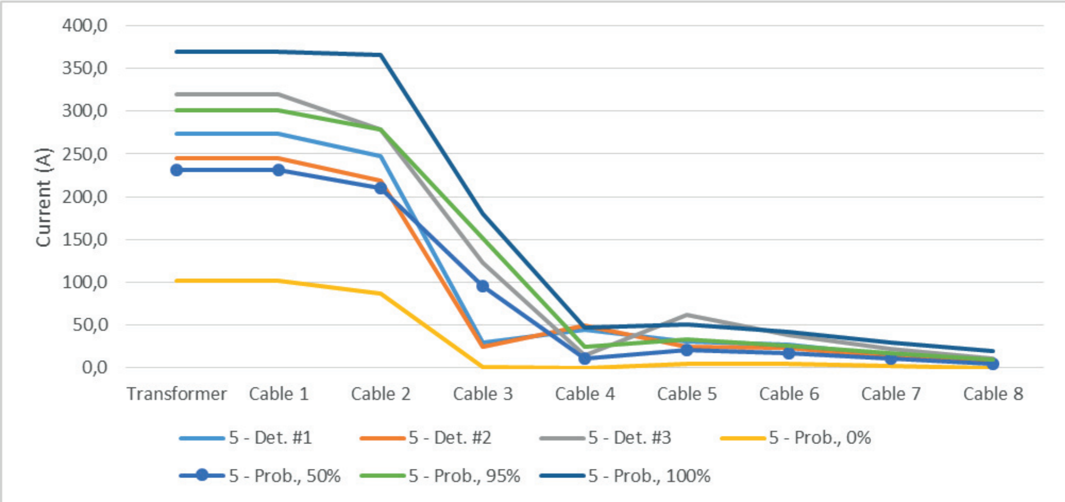


Figure A3-29 Branch currents - Simulation 5 - Winter load with DG (50 kW photovoltaics) and DR (max 90 kW at School)

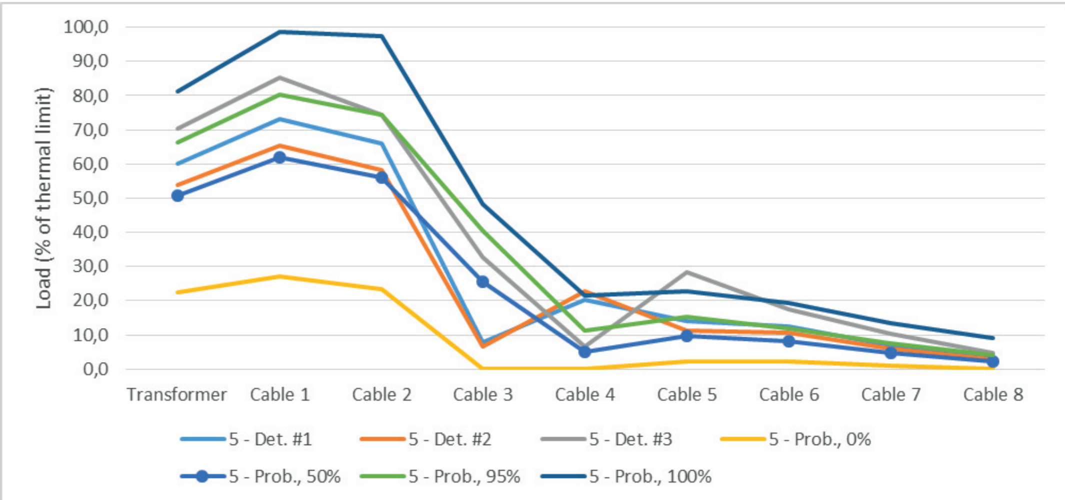


Figure A3-30 Load on transformer and cables - Simulation 5 - Winter load with DG (50 kW photovoltaics) and DR (max 90 kW at School)

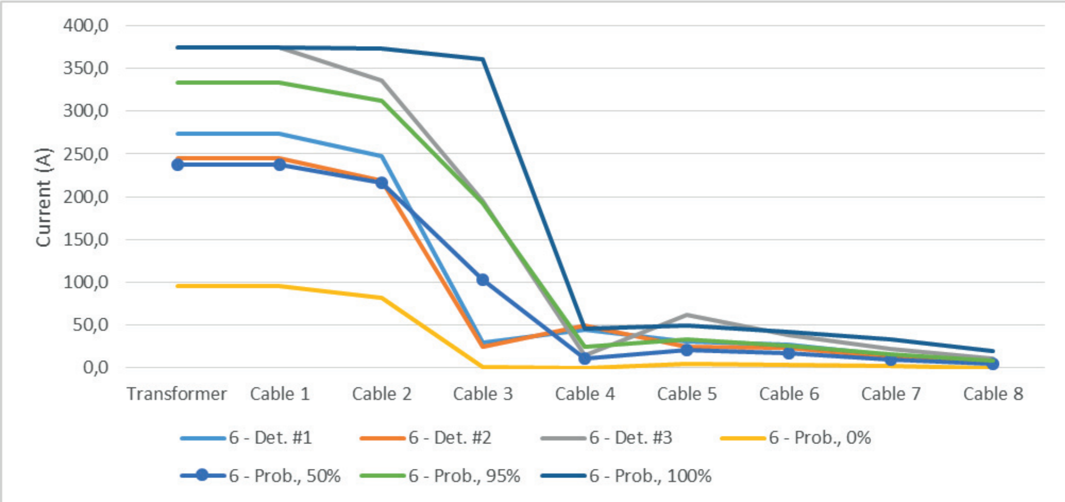


Figure A3-31 Branch currents - Simulation 6 - Winter load with DG (50 kW photovoltaics) and DR (max 100% in Cable 1)

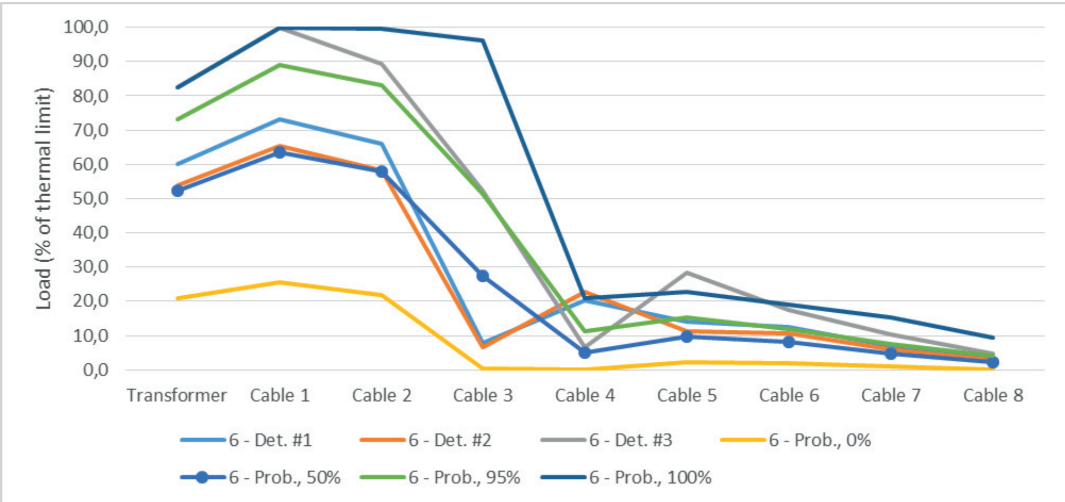


Figure A3-32 Load on transformer and cables - Simulation 6 - Winter load with DG (50 kW photovoltaics) and DR (max 100% in Cable 1)

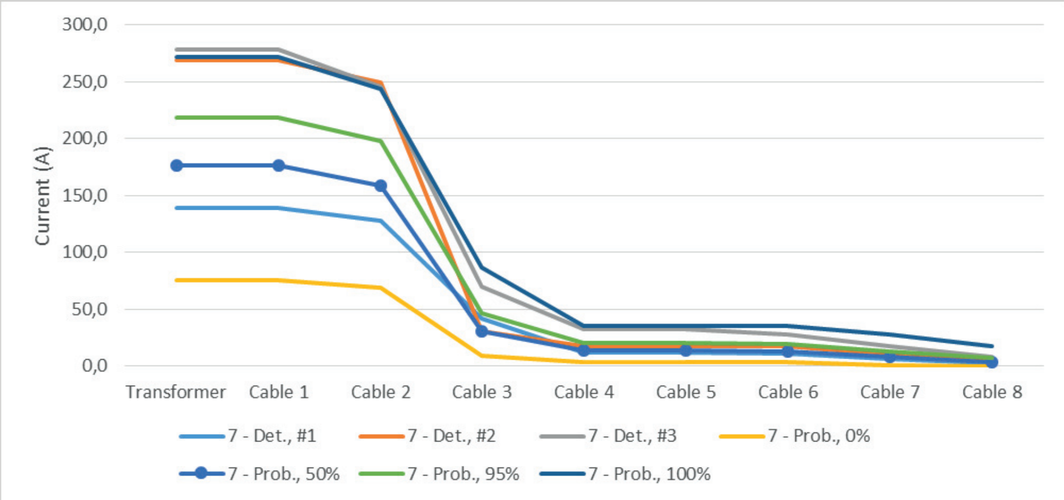


Figure A3-33 Branch currents - Simulation 7 – Summer load

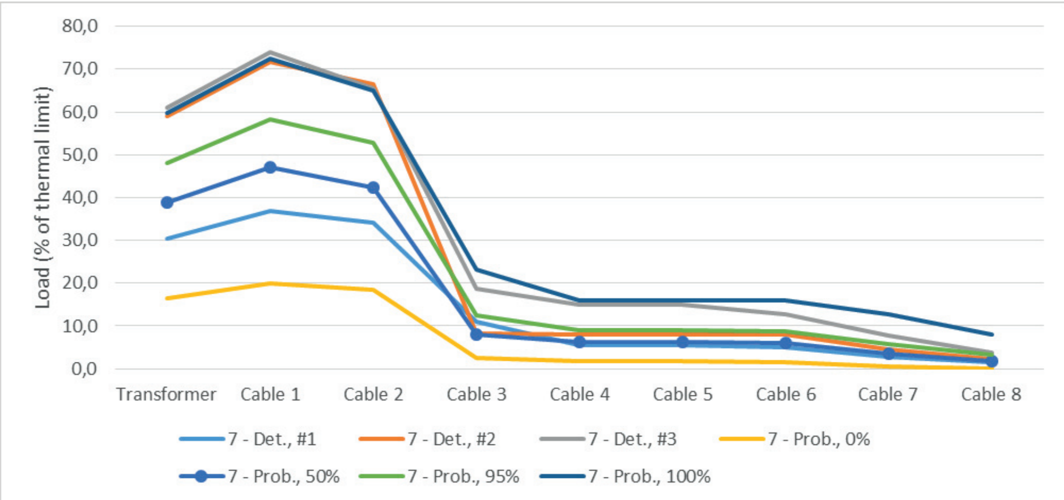


Figure A3-34 Load on transformer and cables - Simulation 7 – Summer load

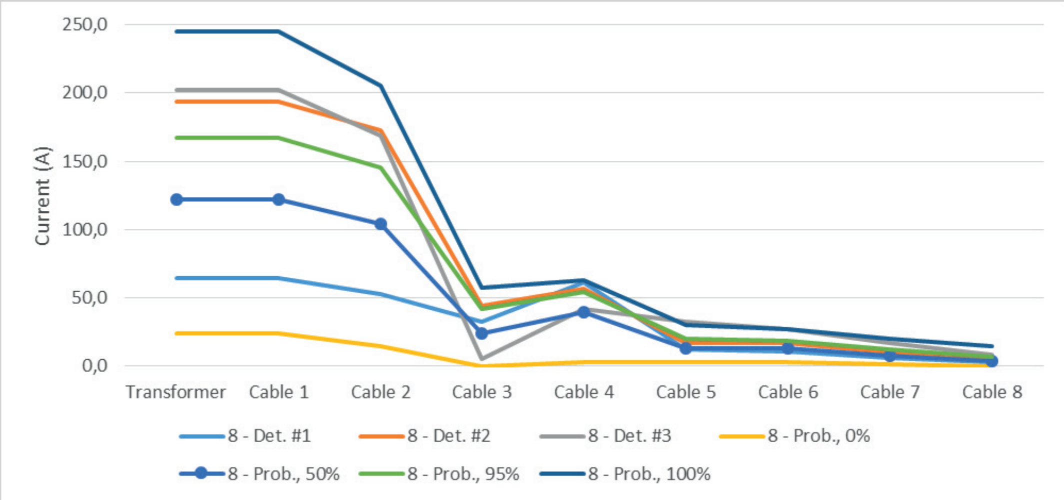


Figure A3-35 Branch currents - Simulation 8 - Summer load with DG (50 kW photovoltaics)

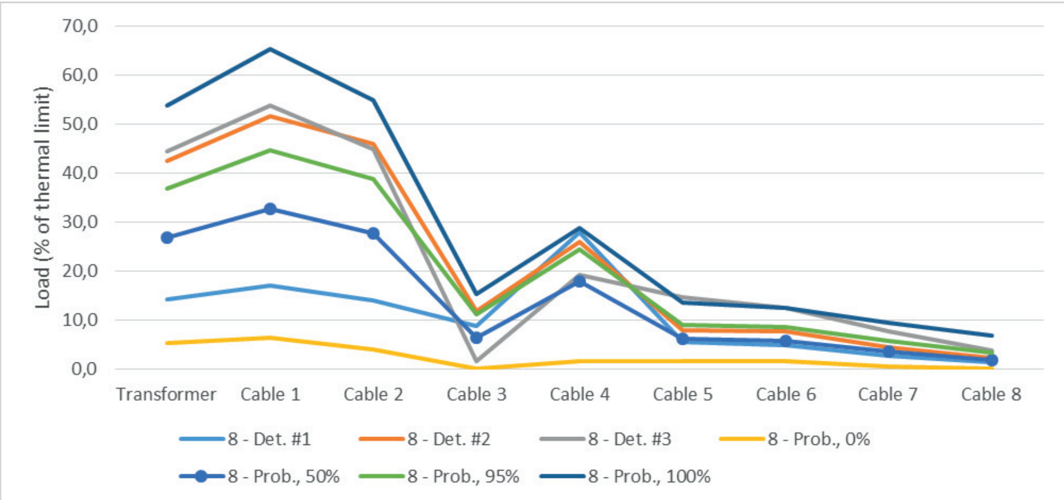


Figure A3-36 Load on transformer and cables - Simulation 8 – Summer load with DG (50 kW photovoltaics)

Probabilistic simulations in *Figure A3-22 Load on transformer and cables - Simulation 1 - Winter load* and *Figure A3-28 Load on transformer and cables - Simulation 4 - Winter load with DG (50 kW photovoltaics)* gives the highest loads in Cable 1 (140 – 160% of thermal limit). Figure A3-37 and Figure A3-38 shows Pareto plot for the load in Cable 1 for these two simulations. The probability for overload on Cable 1 is 2,1% in simulation 1 and 1,5% in simulation 2. DR like the one in Figure A3-26 and Figure A3-32 (max 100 % in Cable 1), will secure the cable by reducing loads in order to keep the load in Cable 1 under 100 %.

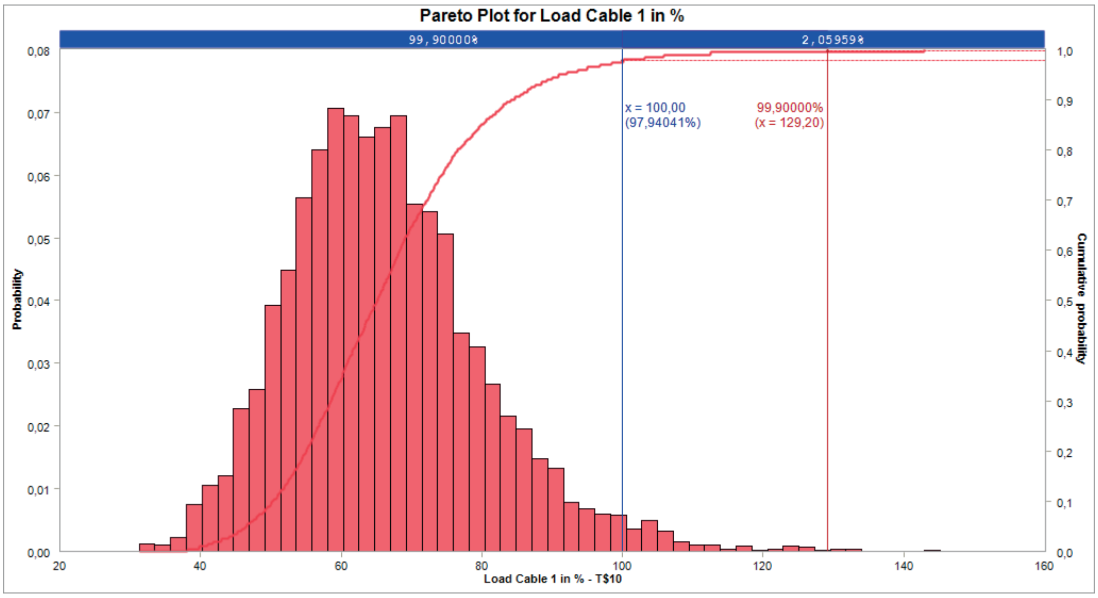


Figure A3-37 Load on cable 1 - Simulation 1 - Winter load

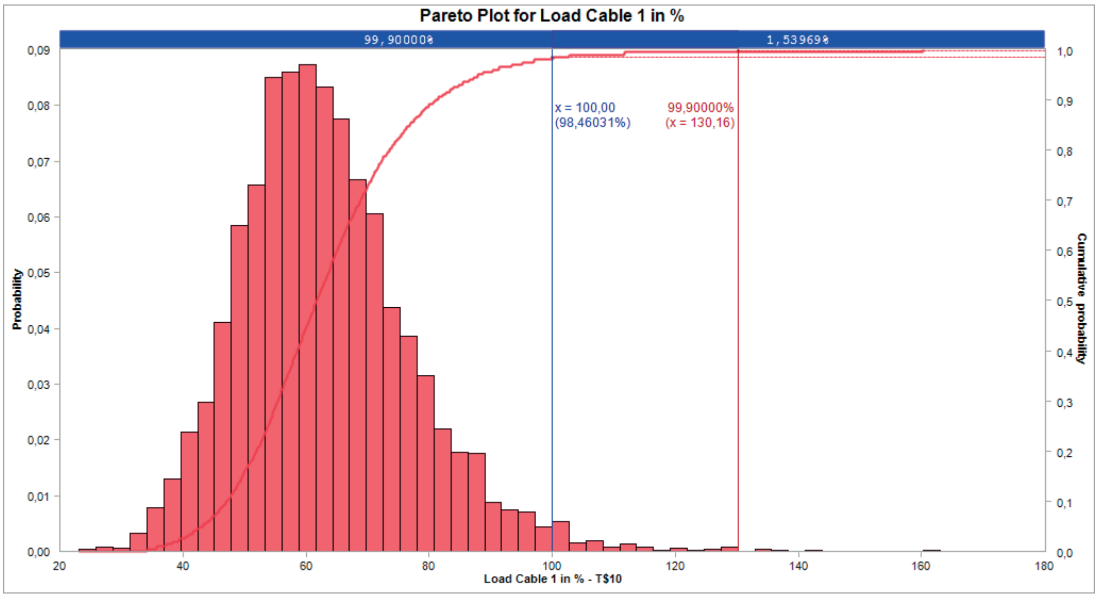


Figure A3-38 Load on cable 1 - Simulation 4 - Winter load with DG (50 kW photovoltaics)

Information about the distribution of loads and risks for overload can be very useful. The risk can be acceptable as it is, or reduced by introducing measures like for example demand response and load shedding.

A.3.4 Total active losses

Probabilistic load models results in probabilistic models for the total active losses as well. The losses are of interest for economic reasons in investment plans and estimating of operational costs.

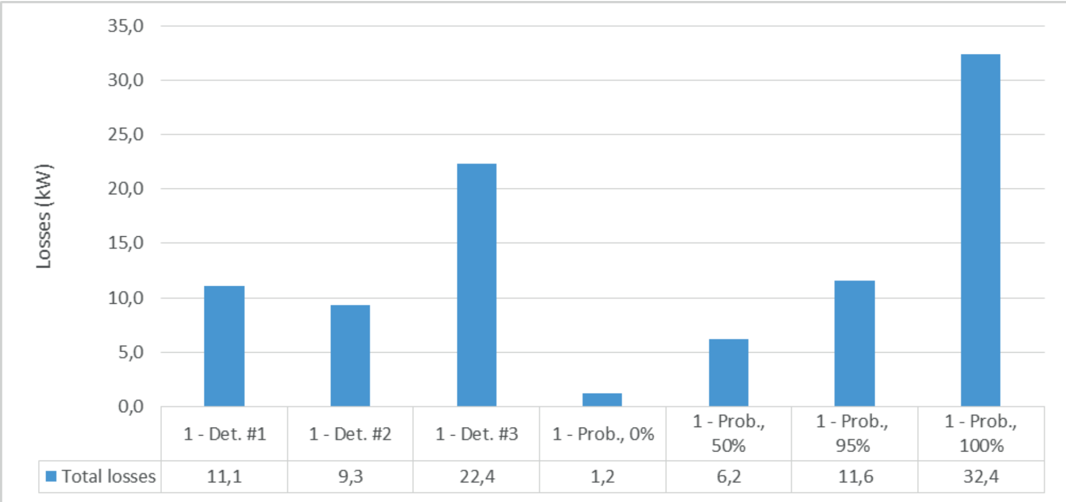


Figure A3-39 Total losses - Simulation 1 - Winter load

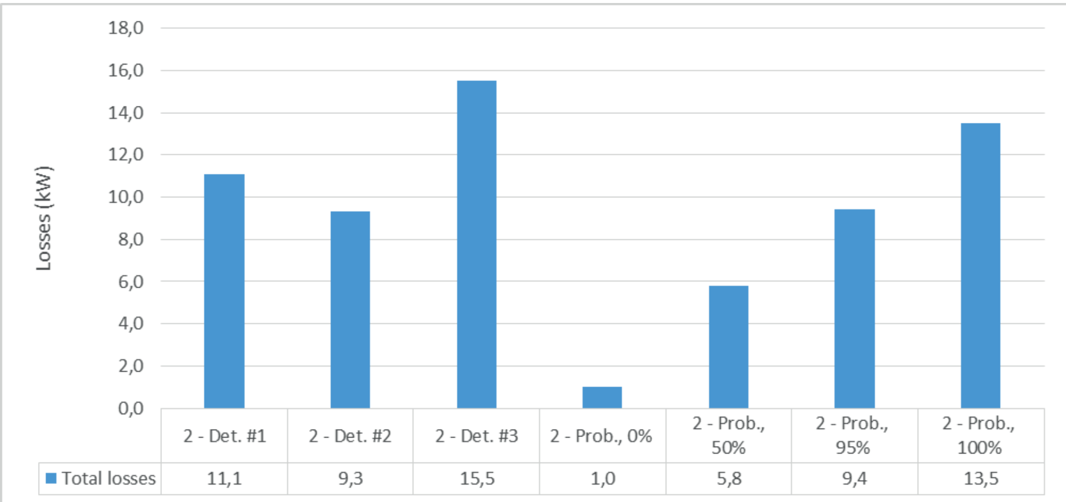


Figure A3-40 Total losses - Simulation 2 - Winter load with DR (max 90 kW at School)

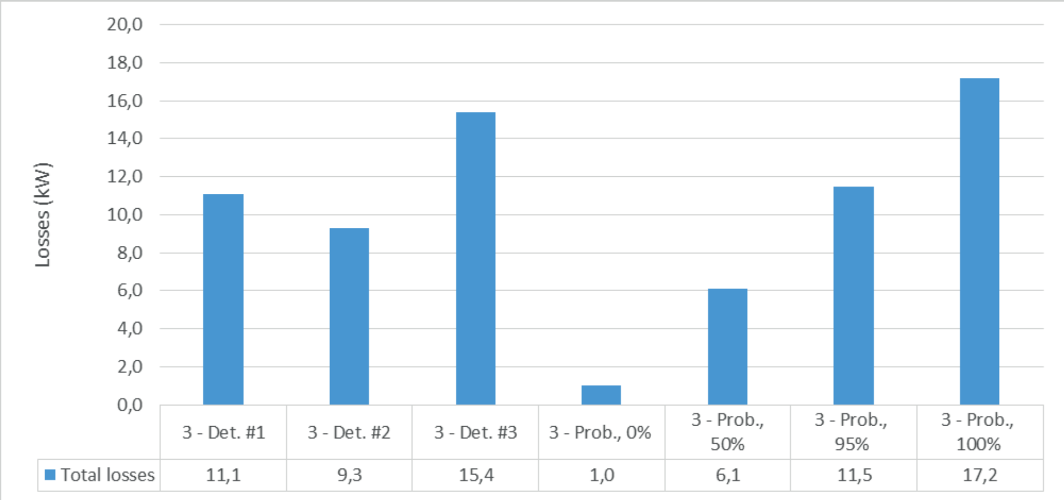


Figure A3-41 Total losses - Simulation 3 - Winter load with DR (max 100% in Cable 1)

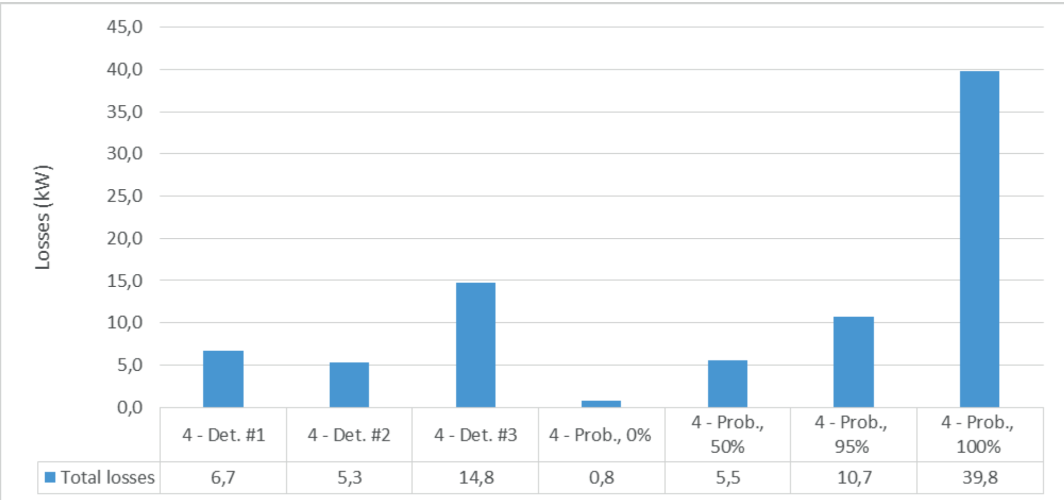


Figure A3-42 Total losses - Simulation 4 - Winter load with DG (50 kW photovoltaics)

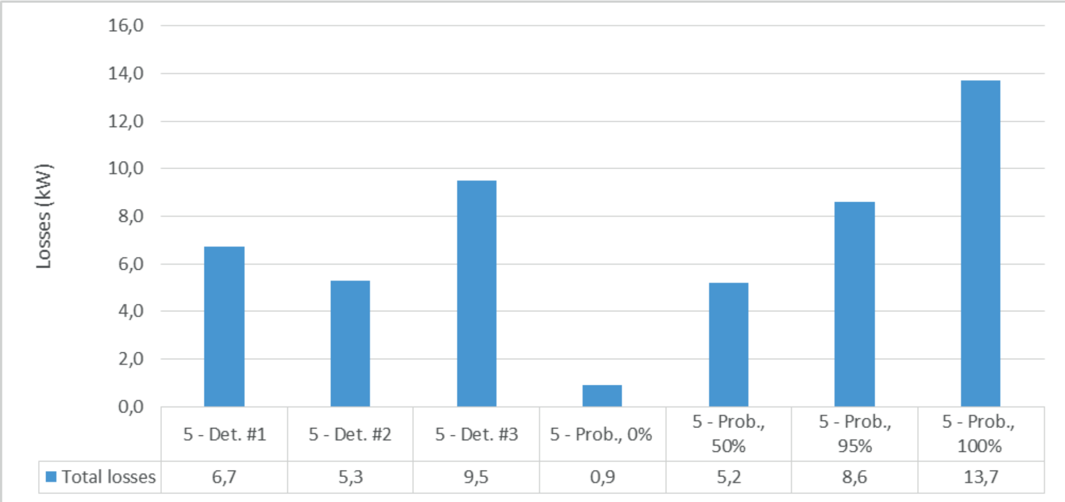


Figure A3-43 Total losses - Simulation 5 - Winter load with DG (50 kW photovoltaics) and DR (max 90 kW at School)

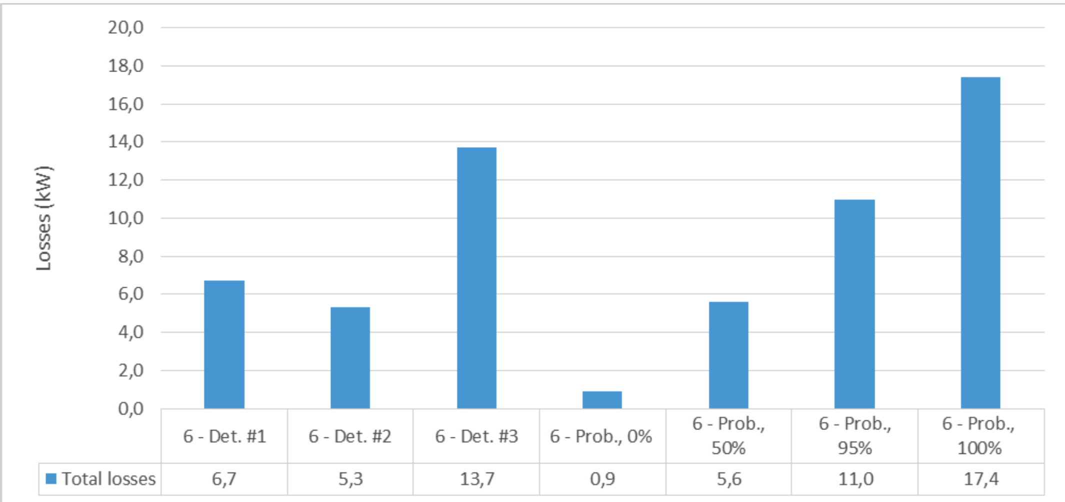


Figure A3-44 Total losses - Simulation 6 - Winter load with DG (50 kW photovoltaics) and DR (max 100% in Cable 1)

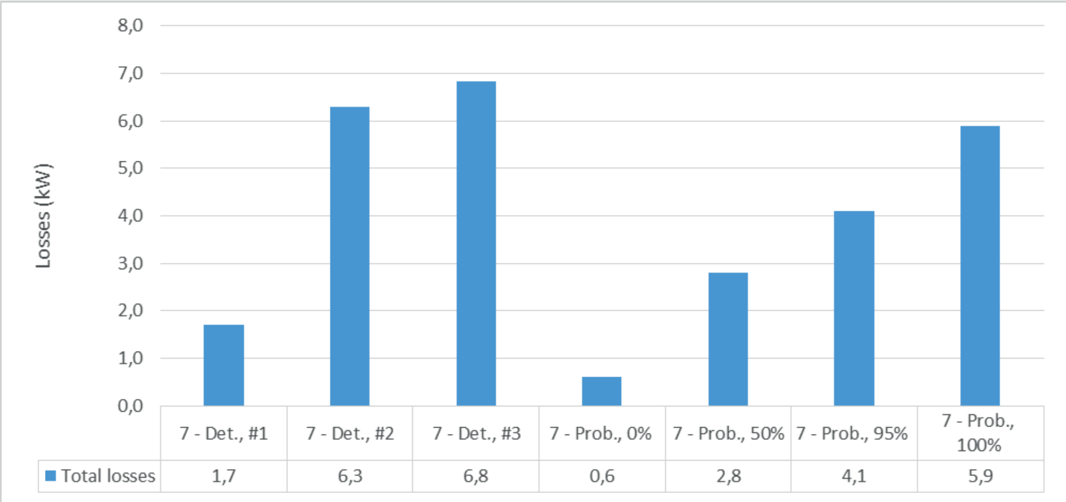


Figure A3-45 Total losses - Simulation 7 – Summer load

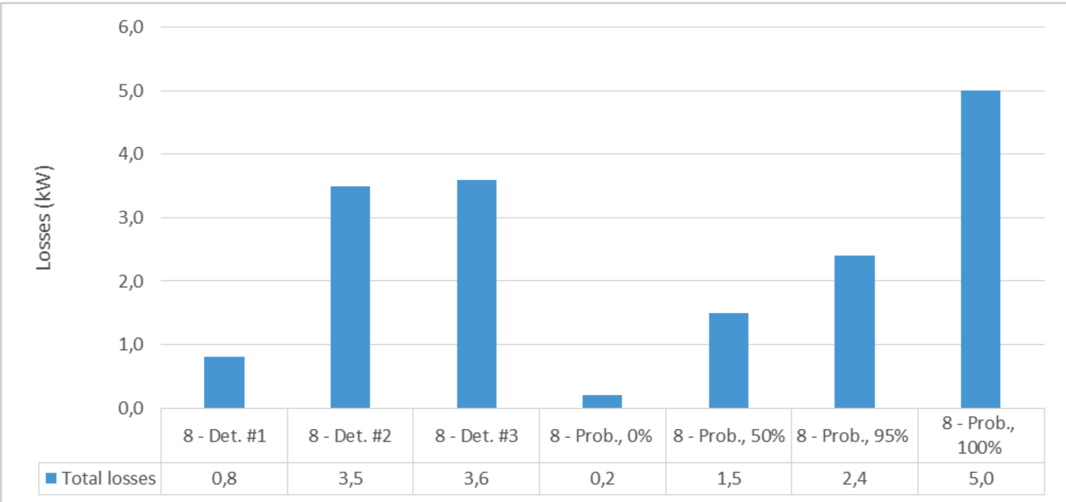


Figure A3-46 Total losses - Simulation 8 – Summer load with DG (50 kW photovoltaics)

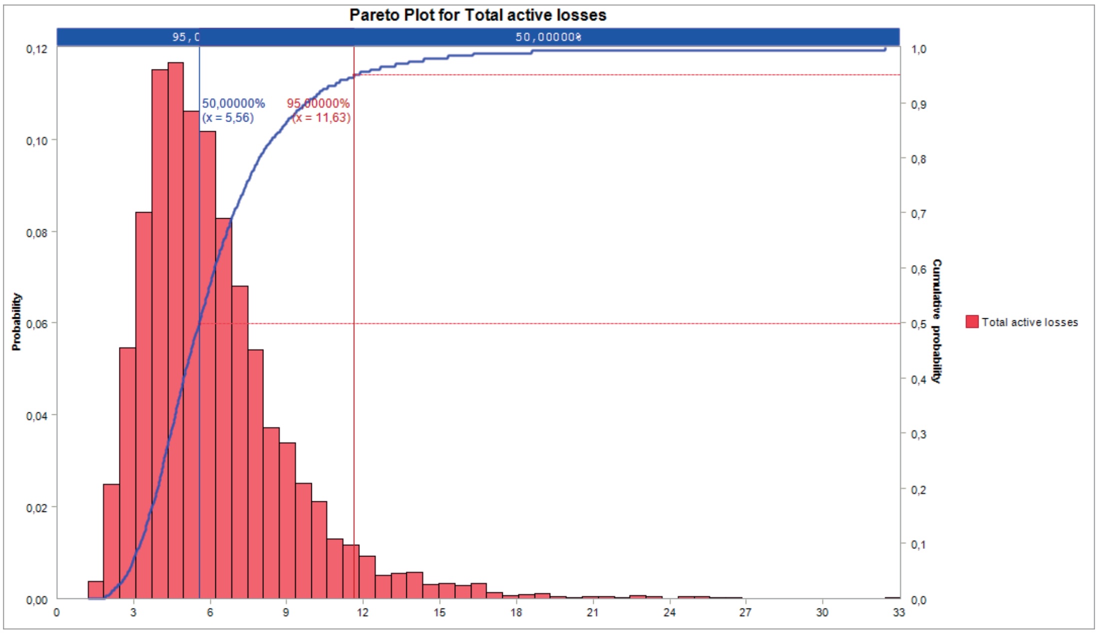


Figure A3-47 Total active losses - Simulation 1 - Winter load – Probabilistic model

Figure A3-47 tells us that in this case there is a 95 % probability that the losses are less than 11,6 kW. Equivalent there is a 50 % probability that the losses are less than 5,6 kW.

APPENDIX B – Renewable energy sources (RES)

Only limited information about RES is given in this appendix. For more information see e.g. the Special Report of the Intergovernmental Panel on Climate Change "*Renewable Energy Sources and Climate Change Mitigation"* (SRREN) [47] and *World Energy Outlook 2015* by IEA [48].

B.1. Bioenergy

Bioenergy is a collective term for the exploitation of biomass for energy purposes.

Biomass is organic material primarily from forest and agriculture, but it also includes all green plants in the sea (aquatic biomass). Wastes made of biomass (e.g. wood materials, paper and cardboard) may also be referred to as bioenergy when recovered and converted into heat and electricity in the incinerator.

The most common application of bioenergy is production of heat. It is also possible to produce electric power, liquid biofuel, biogas and hydrogen from biomass. Bioenergy is the oldest energy source and has been used for heating and cooking in all times. Today it is still the main energy source for at least half the world's population.

The use of biomass for energy purposes is CO_2 neutral in the sense that the CO_2 released during the combustion of a tree corresponds to the amount of CO_2 the tree retrieved from the surroundings and bound up during the growth period. If the use of biomass shall be sustainable, it is important that the harvesting of biomass does not exceed the increment.

In 2008, biomass provided about 10 % of the global primary energy supply. Major biomass uses falls into two broad categories:

1) **Low-efficiency traditional biomass** such as wood, straw, dung and other manures are used for cooking, lighting and space heating, generally by poorer populations in developing countries. This biomass is mostly combusted, creating serious negative impacts on health and living conditions.

2) **High-efficiency modern bioenergy** uses more convenient solids, liquids and gases as secondary energy carriers to generate heat, electricity, combined heat and power (CHP), and transport fuels for various sectors. Liquid biofuels include ethanol and biodiesel for global road transport and some industrial uses. Biomass derived gases, primarily methane, from anaerobic digestion of agricultural residues and municipal solid waste (MSW) treatment are used to generate electricity, heat or both. The most important contribution to these energy services is based on solids, such as chips, pellets, recovered wood previously used and others. Heating includes space and hot water heating such as in district heating systems.

Additionally, the industry sector, such as pulp and paper, forestry, and food industries, consumes biomass primarily as a source for industrial steam.

Some key findings from Technology Roadmap: Bioenergy for Heat and Power – 2012, IEA [49]:
- Bioenergy is the largest source of renewable energy today and can provide heat, electricity, as well as transport fuels.

- By 2050 bioenergy could provide 3 100 TWh of electricity, i.e. 7.5% of world electricity generation. In addition heat from bioenergy could provide 22 EJ (15% of total) of final energy consumption in industry and 24 EJ (20% of total) in the buildings sector in 2050.
- Large-scale (>50 MW) biomass power plants will be important to achieve this roadmap's vision, since they allow for electricity generation at high efficiencies and relatively low costs. Co-firing biomass in coal-fired plants provides an opportunity for short-term and direct reduction of emissions, so avoiding the "carbon lock-in effect" (the inertia that tends to perpetuate fossil fuel based energy systems).
- Smaller-scale (<10 MW) plants have lower electric efficiencies and higher generation costs, and are best deployed in combined heat and power mode, when a sustained heat demand from processes or district heating is available.
- Biomass heat and electricity can already be competitive with fossil fuels under favorable circumstances today. Through standardizing optimized plant designs, and improving electricity generation efficiencies, bioenergy electricity generation costs could become generally competitive with fossil fuels under a CO_2 price regime.
- Enhanced research, development and demonstration (RD&D) efforts will bring new technologies such as small-scale, high efficiency conversion technologies to the market. Development of biomass conversion to biomethane for injection into the natural gas grid could become one very interesting option, since it could exploit existing investments in gas infrastructure and provide flexible electricity.
- International trade in biomass and biomass intermediates (pellets, pyrolysis oil, biomethane) will be vital to match supply and demand in different regions and will require large-scale development of biomass and its intermediates.
- In the next 10 years to 20 years, cost differences between bioenergy and fossil derived heat and power will remain a challenge. Economic support measures specific to different markets will be needed as transitional measures, leading to cost competitiveness in the medium term.

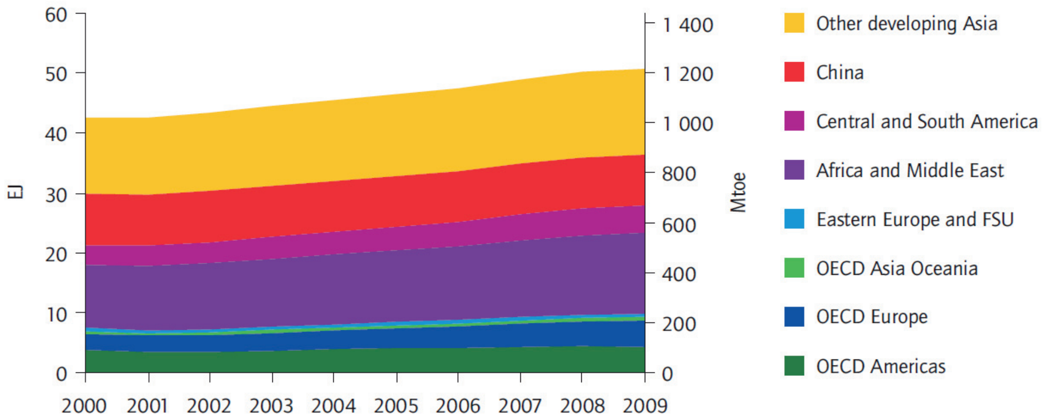


Figure B1-1 Global primary bioenergy supply [49]

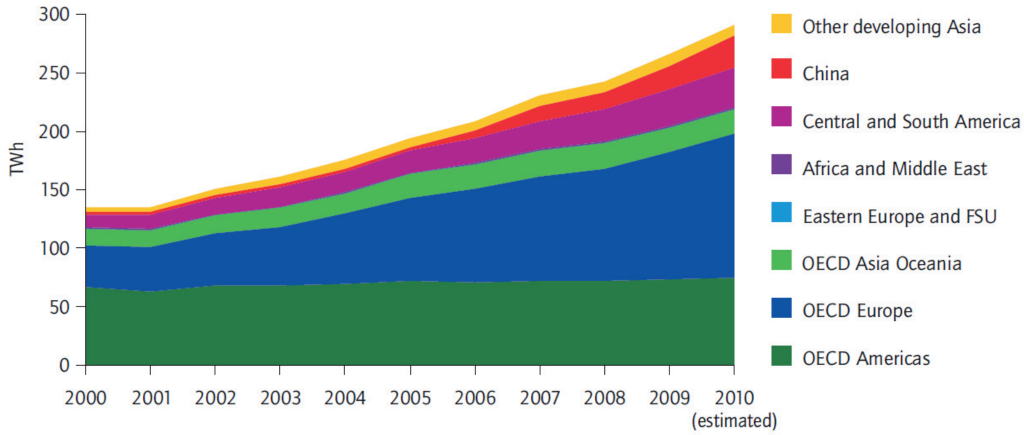


Figure B1-2 Global bioenergy electricity generation 2000 - 2010 [49]

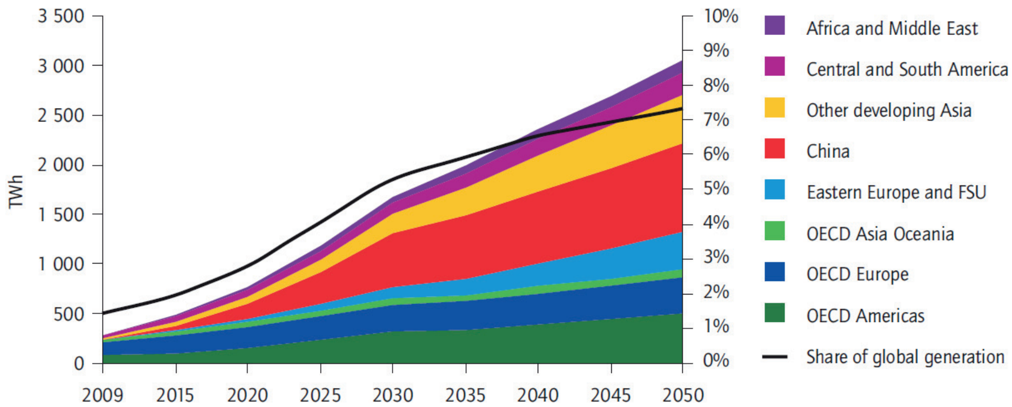


Figure B1-3 Roadmap vision of bioenergy electricity generation by region [49]

Bioenergy in Norway:

Bioenergy has always played an important role in the Norwegian energy supply. The total consumption of bioenergy in 2012 was about 16 TWh. About 45 percent of this is the use of firewood in households. About 25 percent of the total consumption of bioenergy, or 4 TWh in 2012, is energy from recycling of bio-based waste from industry. This figure is significantly reduced in recent years as a result of the closures in the pulp and paper industry.

Table B1-1 Bioenergy in Norway 2012 [26]

Categrory	TWh
Firewood in households	7 TWh
Woodchips in industry and district- and local heating networks	2 TWh
Wood pellets and briquettes	0.5 TWh
Biogas	0.2 TWh
Bio-oil	0.8 TWh
Biofuels blended in conventional fuels	1.6 TWh

Recycling of bio-based waste from industry	4 TWh
SUM	16.1 TWh

The annual biomass growth in Norway is estimated to be about 425 TWh. 325 TWh is land based biomass and 100 TWh is aquatic biomass produced in freshwater and along the coast. Approximately 15 to 20 percent of this growth, or 75 TWh, is used for food, feed, products (primarily paper products and wood materials) and energy. The biomass used in Norway today, mainly comes from the forest.

Several reports show a significant potential for increased extraction of forest resources in Norway. NVE[22] indicated in 2011 that about 14 TWh more biomass will be possible to realize within a limit of 0.30 NOK/kWh, but require increased logging, thinning and utilization of branches and tops.

B.2. Direct solar Energy

Direct solar energy technologies are diverse in nature. The technologies can be divided into four groups:

1) Solar thermal, which includes both active and passive heating of buildings, domestic and commercial solar water heating, swimming pool heating and process heat for industry
2) Photovoltaic (PV) electricity generation via direct conversion of sunlight to electricity generation by photovoltaic cells
3) Concentrating solar power (CSP) electricity generation by optical concentration of solar energy to obtain high-temperature fluids or materials to drive heat engines and electrical generators.
4) Solar fuels production methods, which use solar energy to produce useful fuels. Solar fuels that can be produced include synthesis gas (syngas, i.e., mixed gases of carbon monoxide and hydrogen), pure hydrogen (H_2) gas, dimethyl ether (DME) and liquids such as methanol and diesel. A solar fuel can be produced and stored for later usage making it an alternative to fossil fuels.

Solar energy constitutes the thermal radiation emitted by the Sun's outer layer. Just outside Earth's atmosphere, this radiation, called solar irradiance, has a magnitude that averages 1,367 W/m^2 for a surface perpendicular to the Sun's rays. At ground level (generally specified as sea level with the sun directly overhead), this irradiance is attenuated by the atmosphere to about 1,000 W/m^2 in clear sky conditions within a few hours of noon—a condition called 'full sun'.

The theoretical solar energy potential, which indicates the amount of irradiance at the Earth's surface (land and ocean) that is theoretically available for energy purposes, has been estimated at 3.9.10^6 EJ/yr. This number, clearly intended for illustrative purposes only, would require the full use of all available land and sea area at 100% conversion efficiency. A more useful metric is the technical potential; this requires assessing the fraction of land that is of practical use for conversion devices using a more realistic conversion efficiency. Estimates for solar energy's technical potential range from 1,575 to 49,837 EJ/yr (438 – 4,139 PWh/yr), which is roughly 4 to 130 times the world's primary energy consumption in 2012.

Some key-findings from Technology Roadmap: Solar Photovoltaic Energy – 2014, IEA [50]:

- Since 2010, the world has added more solar photovoltaic (PV) capacity than in the previous four decades. Total global capacity overtook 150 gigawatts (GW) in early 2014.
- The geographical pattern of deployment is rapidly changing. While a few European countries, led by Germany and Italy, initiated large-scale PV development, since 2013, the People's Republic of China has led the global PV market, followed by Japan and the United States.

[22] Norwegian Water Resources and Energy Directorate

- PV system prices have been divided by three in six years in most markets, while module prices have been divided by five.
- The 2014 roadmap envisions PV's share of global electricity reaching 16% by 2050, a significant increase from the 11% goal in the 2010 roadmap.
- Achieving the roadmap's vision of 4 600 GW of installed PV capacity by 2050 would avoid the emission of up to 4 gigatonnes (Gt) of carbon dioxide (CO_2) annually.

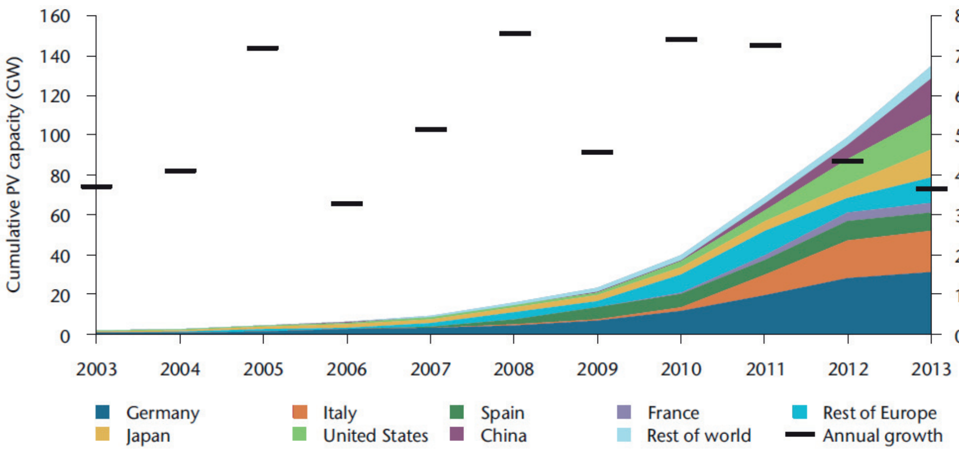


Figure B2-1 Global cumulative growth of PV capacity [50]

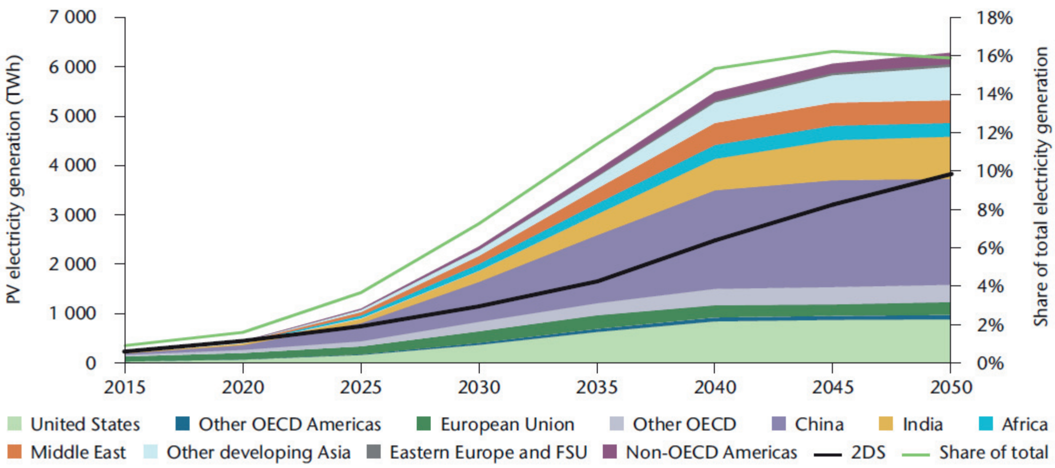


Figure B2-2 Regional production of PV electricity envisioned in IEA Technology Roadmap 2014 [50]

In the scenario visualized in Figure B2-2 PV provides 16 % of global electricity by 2050, and China has a 35 % share of the total PV electricity production.

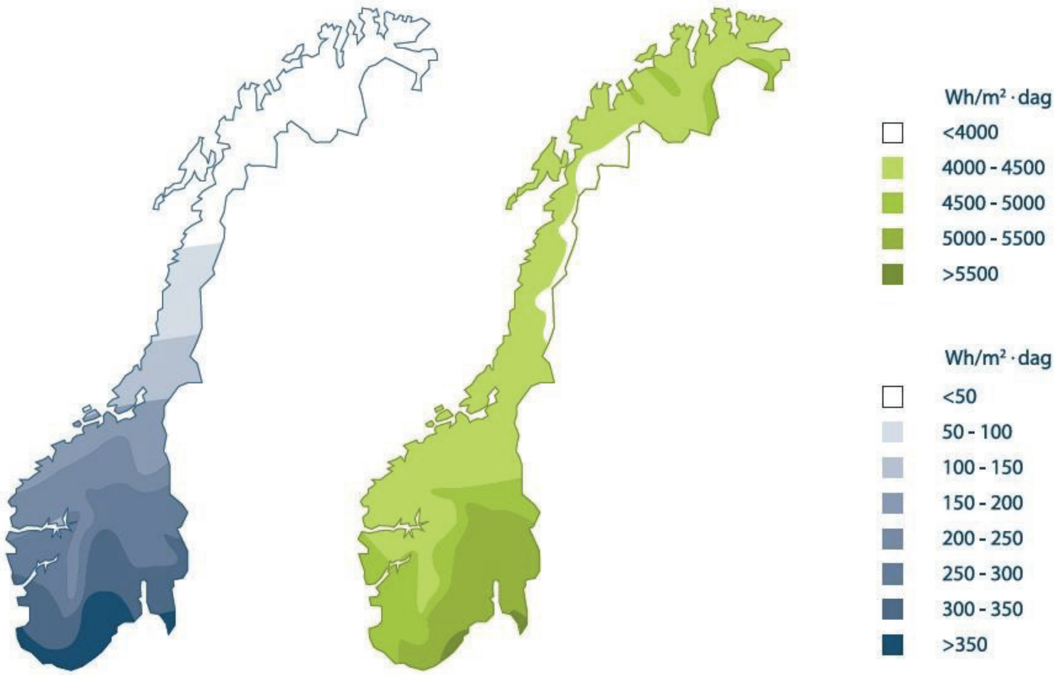
Direct solar energy in Norway

In Norway the annual solar irradiance against a horizontal surface varies between 700 – 1100 kWh/m^2, depending on the geographical conditions. The best conditions for solar energy in Norway are completely in the south and east part of the country and in the inner parts of central Norway. The northwest coast and the northern part of Norway have the lowest insolation and the poorest conditions for solar energy. Despite the fact that the solar irradiation in Norway is relatively low compared to more suitable places in the world, the potential for solar energy (both electricity and heat) is significantly. If 0.4‰ of Norway's land area were covered with photovoltaics, it would cover the total Norwegian domestic electricity consumption.

Norway may be suitable for utilization of solar energy for both electricity (photovoltaics) and heat (solar collectors). Solar collectors can be used for heating tap water or heating buildings. One challenge with both photovoltaics and solar collectors in Norway is that the demand for electricity and heat is greatest in the winter when the insolation is at its lowest. Yet one of the reasons why many places in Norway are suitable for solar development is just cold and dry climate, which helps keep the operating temperature of the photovoltaics down and thus reduce both heat losses and wear on the photovoltaics. Overheating of the photovoltaics is a challenge in warmer climes.

Except from this, Norway's major hydropower resource is a significant advantage in a future major development of photovoltaics. Solar energy is a relatively unpredictable source and the output will vary considerably from day to day (cloudy or sunny) and season to season (big difference between summer and winter). Norway's great advantage is that solar energy can be used when the insolation is high while saving water in ponds and lakes. When solar insolation is low it is possible to compensate hydropower. This is much cheaper than building enormous batteries for storing solar energy during day. Another advantage of building photovoltaic plants in Norway is that there are relatively much available land area and it is sparsely populated. Larger photovoltaic plants can be built without considerable conflicts with other land use.

There is a big difference in annual solar irradiation between the various regions in Norway, and between summer and winter. Figure B2-3 shows average solar irradiance against a horizontal surface during a day in January and July respectively.



(Illustration: Endre Barstad)

Figure B2-3 Average daily solar irradiation in January and July [26]

2.2 MWp (megawatt-peak) new capacity of photovoltaics installed in Norway during 2014. This is three times as much as the year before and can be characterized as a turning point for photovoltaics in this country. 1.4 MWp of this new capacity was connected to the distribution grid.

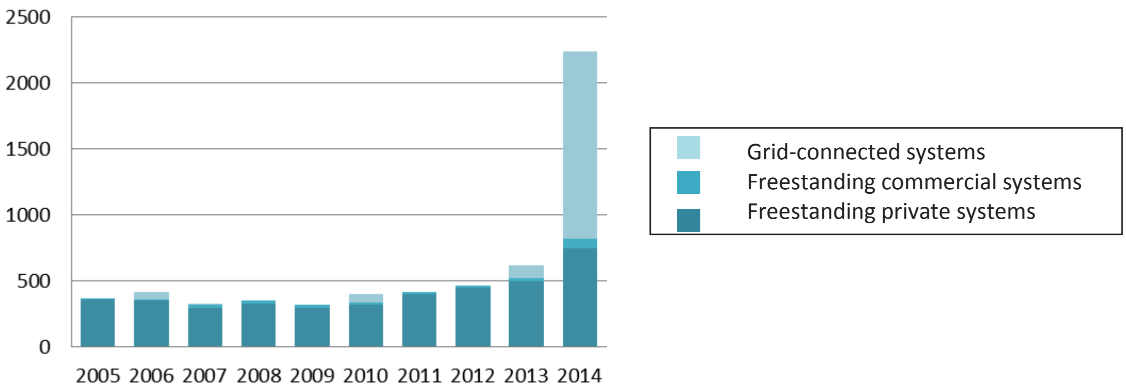


Figure B2-4 Annually installed new capacity of photovoltaics in Norway in kWp [26]

Total accumulated photovoltaic capacity in Norway is 12.8 MWp and is dominated by solar panels in private cottages and lighthouses. Accumulated capacity of grid connected systems is 1.7 MWp which gives an annual electricity generation of about 1.4 GWh.

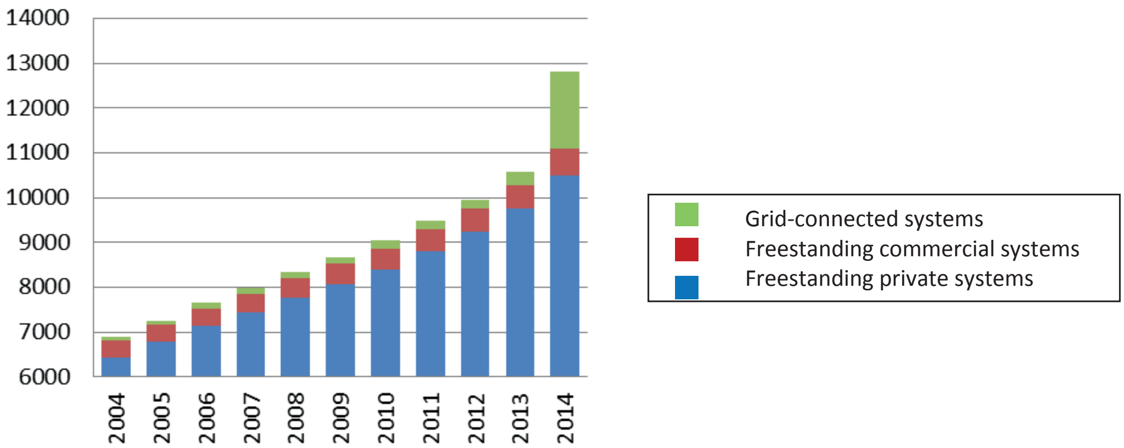


Figure B2-5 Accumulated capacity of photovoltaics in Norway in kWp [26]

B.3. Geothermal energy

Geothermal resources consist of thermal energy from the Earth's interior stored in both rock and trapped steam or liquid water, and are used to generate electric energy in a thermal power plant or in other domestic and agro-industrial applications requiring heat as well as in CHP applications. Climate change has no significant impacts on the effectiveness of geothermal energy.

Technical potentials are presented on a regional basis in

Table B3-1. The regional breakdown is based on the methodology applied by the Electric Power Research Institute to estimate theoretical geothermal potentials for each country, and then countries are grouped regionally. Thus, the present disaggregation of global technical potential is based on factors accounting for regional variations in the average geothermal gradient and the presence of either a diffuse geothermal anomaly or a high-temperature region associated with volcanism or plate boundaries. The separation into electric and thermal (direct uses) potentials is somewhat arbitrary in that most higher-temperature resources could be used for either, or both, in CHP applications depending on local market conditions.

The heat extracted to achieve the technical potentials can be fully or partially replenished over the long term by the continental terrestrial heat flow of 315 EJ/yr at an average flux of 65 mW/m^2

Table B3-1 Geothermal technical potentials on continents for the IEA regions [47]

REGION[1]	Electric technical potential (EJ/yr) at depths to:						Technical potentials (EJ/yr) for direct uses	
	3 km		5 km		10 km			
	Lower	Upper	Lower	Upper	Lower	Upper	Lower	Upper
OECD North America	25.6	31.8	38.0	91.9	69.3	241.9	2.1	68.1
Latin America	15.5	19.3	23.0	55.7	42.0	146.5	1.3	41.3
OECD Europe	6.0	7.5	8.9	21.6	16.3	56.8	0.5	16.0
Africa	16.8	20.8	24.8	60.0	45.3	158.0	1.4	44.5
Transition Economies	19.5	24.3	29.0	70.0	52.8	184.4	1.6	51.9
Middle East	3.7	4.6	5.5	13.4	10.1	35.2	0.3	9.9
Developing Asia	22.9	28.5	34.2	82.4	62.1	216.9	1.8	61.0
OECD Pacific	7.3	9.1	10.8	26.2	19.7	68.9	0.6	19.4
Total	**117.5**	**145.9**	**174.3**	**421.0**	**317.5**	**1,108.6**	**9.5**	**312.2**

Some key findings from Technology Roadmap: Geothermal Energy and Power, IEA 2011 [51]:

- By 2050, geothermal electricity generation could reach 1,400 TWh per year, *i.e.* around 3.5% of global electricity production.
- Geothermal heat could contribute 1,600 TWh thermal energy annually by 2050, *i.e.* 3.9% of projected final energy for heat.
- In the period to 2030, rapid expansion of geothermal electricity and heat production will be dominated by accelerated deployment of conventional high-temperature hydrothermal resources, driven by relatively attractive economics but limited to areas where such resources are available. Deployment of low- and medium-temperature hydrothermal resources in deep aquifers will also grow quickly, reflecting wider availability and increasing interest in their use for both heat and power.
- By 2050, more than half of the projected increase comes from exploitation of ubiquitously available hot rock resources, mainly via enhanced geothermal systems (EGS). Substantially higher research, development and demonstration (RD&D) resources are needed in the next decades to ensure EGS becomes commercially viable by 2030.
- A holistic policy framework is needed that addresses technical barriers relating to resource assessment, accessing and engineering the resource, geothermal heat use and advanced geothermal technologies. Moreover, such a holistic framework needs to address barriers relating to economics, regulations, market facilitation and RD&D support.

- Policy makers, local authorities and utilities need to be more aware of the full range of geothermal resources available and of their possible applications in order to develop consistent policies accordingly. This is particularly true for geothermal heat, which can be used at varying temperatures for a wide variety of tasks.
- Important R&D priorities for geothermal energy include accelerating resource assessment, development of more competitive drilling technology and improving EGS technology as well as managing health, safety and environmental (HSE) concerns.
- Advanced technologies for offshore, geo-pressured and super-critical (or even magma) resources could unlock a huge additional resource base. Where reasonable, co-produced hot water from oil and gas wells can be turned into an economic asset.

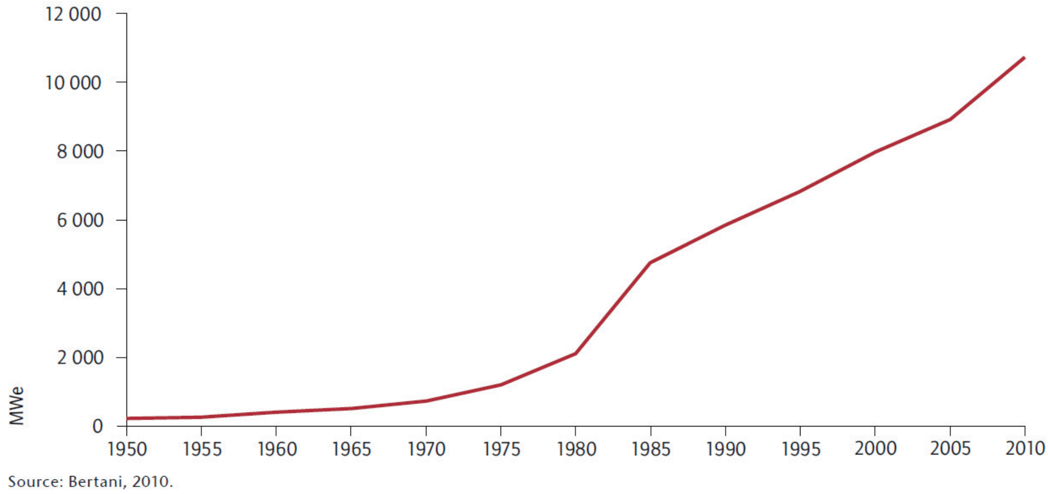


Figure B3-1 Global development installed capacity geothermal power (MW) [51]

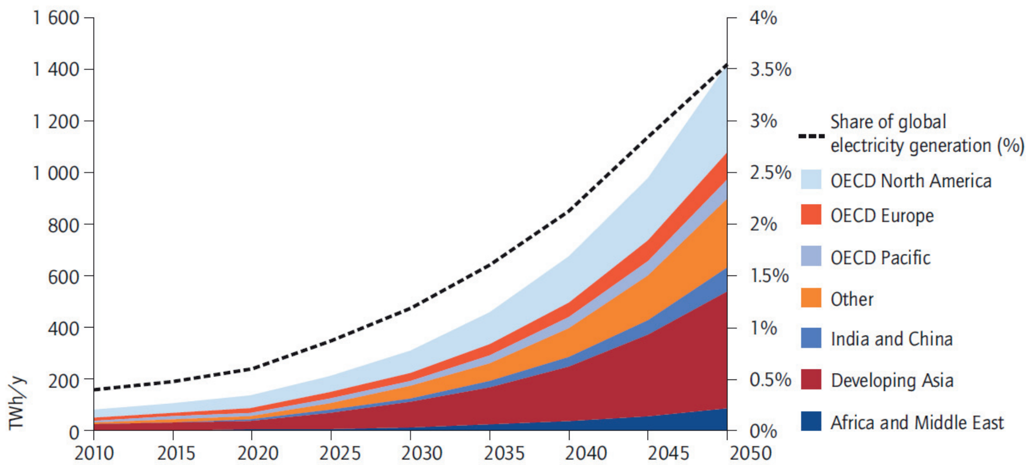


Figure B3-2 Roadmap vision of geothermal power production by region (TWh/y) [51]

Geothermal energy in Norway:
Norway is a cold country also regarding geothermal energy – with temperature gradients between 10 and 30 K/km down the ground.

Measurements performed by Geological Survey of Norway (NGU) suggest that the temperature at most places in Norway is above 100 °C at five kilometers deep. The Oslo area has the largest potential because in this area there are rocks (Uranium and Thorium) that produce heat. In this area it is possible to find areas with temperature 150 °C at the same depth.

Ground source heat pumps are the only utilization of geothermal energy in Norway per 2011. It is mostly closed systems with energy wells in rock that are used. Compared to air-air and air-water heat pumps, ground source heat pumps deliver energy independent of air temperature and they need less maintenance. A total of 26,000 plants of this type is installed with a total capacity of approximately 3,500 MW thermal heat.

In 2011 The Norwegian Water Resources and Energy Directorate (NVE) published a report which stated that ground source heat pumps theoretically can cover the total demand for heating and cooling in Norway. According to NVE, geothermal energy can represent a significant contribution to the Norwegian energy supply. Geothermal energy can replace most of the oil and electricity used for heating and cooling today. NGU estimates the technical potential for energy savings through the use of geothermal energy and heat pumps in Norway to be about 37 TWh.

B.4. Hydropower

Hydropower is a renewable energy source where power is derived from the energy of water moving from higher to lower elevations. It is a proven, mature, predictable and cost-competitive technology. The mechanical power of falling water is an old tool used for various services from the time of the Greeks more than 2,000 years ago. The world's first hydroelectric station of 12.5 kW was commissioned on 30 September 1882 on Fox River at the Vulcan Street Plant in Appleton, Wisconsin, USA. Though the primary role of hydropower in global energy supply today is in providing centralized electricity generation, hydropower plants also operate in isolation and supply independent systems, often in rural and remote areas of the world.

The annual global technical potential for hydropower generation is 14,576 TWh with a corresponding estimated total capacity potential of 3,721 GW—four times the currently installed global hydropower capacity. Undeveloped capacity ranges from about 47% in Europe to 92% in Africa, indicating large and well distributed opportunities for hydropower development worldwide. Asia and Latin America have the largest technical potentials and the largest undeveloped resources. Africa has highest portion of total potential that is still undeveloped.

Table B4-1 Regional hydro power technical potential in terms of annual generation and installed capacity (GW); and current generation, installed capacity, average capacity factors and resulting undeveloped potential as of 2009 [47]

World region	Technical potential, annual generation TWh/yr (EJ/yr)	Technical potential, installed capacity (GW)	2009 Total generation TWh/yr (EJ/yr)	2009 Installed capacity (GW)	Undeveloped potential (%)	Average regional capacity factor (%)
North America	1,659 (5.971)	388	628 (2.261)	153	61	47
Latin America	2,856 (10.283)	608	732 (2.635)	156	74	54
Europe	1,021 (3.675)	338	542 (1.951)	179	47	35
Africa	1,174 (4.226)	283	98 (0.351)	23	92	47
Asia	7,681 (27.651)	2,037	1,514 (5.451)	402	80	43
Australasia/Oceania	185 (0.666)	67	37 (0.134)	13	80	32
World	**14,576 (52.470)**	**3,721**	**3,551 (12.783)**	**926**	**75**	**44**

It is noteworthy that the total installed capacities of hydropower in North America, Latin America, Europe and Asia are of the same order of magnitude and, in Africa and Australasia/Oceania, an order of magnitude less; Africa due to underdevelopment and Australasia/Oceania because of size, climate and topography. The global average capacity factor for hydropower plants is 44%. Capacity factor can be indicative of how hydropower is employed in the energy mix (e.g., peaking versus base-load generation) or water availability, or can be an opportunity for increased generation through equipment upgrades and operational optimization.

The resource potential for hydropower could change due to climate change. Based on a limited number of studies to date, the climate change impacts on existing global hydropower systems is expected to be slightly positive, even though individual countries and regions could have signify cant positive or negative changes in precipitation and runoff. Annual power production capacity in 2050 could increase by 2.7 TWh in Asia under the SRES A1B scenario, and decrease by 0.8 TWh in Europe. In other regions, changes are found to be even smaller. Globally, the changes caused by climate change in the existing hydropower production system are estimated to be less than 0.1%, although additional research is needed to lower the uncertainty of these projections.

Hydropower's large capacity range, its flexibility, storage capability (when coupled with a reservoir), and ability to operate in a stand-alone mode or in grids of all sizes enables it to deliver a broad range of services.

Hydropower can be delivered through the national and regional electric grid, distribution grids, mini-grids and in isolated mode. Realization has been growing in developing countries that small-scale hydropower schemes have an important role to play in the socioeconomic development of remote rural, especially hilly, areas as those can provide power for industrial, agricultural and domestic uses. In China, small-scale HPPs[23] have been one of the most successful examples of rural electrification, where over 45,000 small HPPs totaling over 55,000 MW of capacity and producing 160 TWh of generation annually benefit over 300 million people.

With a very large reservoir relative to the size of the hydropower plant (or very consistent river flows), HPPs can generate power at a near constant level throughout the year (i.e., operate as a base-load plant). Alternatively, in the case that the hydropower capacity far exceeds the amount of reservoir storage, the hydropower plant is sometimes referred to as energy-limited. An energy-limited hydro plant would exhaust its 'fuel supply' by consistently operating at its rated capacity throughout the year. In this case, the use of reservoir storage allows hydropower generation to occur at times that are most valuable from the perspective of the power system rather than at times dictated solely by river flows. Since electrical demand varies during the day and night, during the week and seasonally, storage hydropower generation can be timed to coincide with times where the power system needs are the greatest. In part, these times will occur during periods of peak electrical demand. Operating hydropower plants in a way to generate power during times of high demand is referred to as peaking operation (in contrast to base-load). Even with storage, however, hydropower generation will still be limited by the size of the storage, the rated electrical capacity of the hydropower plant, and downstream flow constraints for irrigation, recreation or environmental uses of the river flows. Hydropower peaking may, if

[23] HPPs = hydro power plants

the outlet is directed to a river, lead to rapid fluctuations in river flow, water-covered area, depth and velocity. In turn this may, depending on local conditions, lead to negative impacts in the river unless properly managed.

In addition to hydropower supporting fossil and nuclear generation technologies, it can also help reduce the challenges with integrating variable renewable resources. In Denmark, for example, the high level of variable wind energy (>20% of the annual energy demand) is managed in part through strong interconnections (1 GW) to Norway, which has substantial storage hydropower. More interconnectors to Europe may further support increasing the share of wind power in Denmark and Germany. Increasing variable generation will also increase the amount of balancing services, including regulation and load following, required by the power system. In regions with new and existing hydropower facilities, providing these services from hydropower may avoid the need to rely on increased part-load and cycling of conventional thermal plants to provide these services.

However, hydro has the potential to offer significant power system services in addition to energy and capacity, interconnecting and reliably utilizing HPPs may also require changes to power systems. The interconnection of hydropower to the power system requires adequate transmission capacity from HPPs to demand centers. Adding new HPPs has in the past required network investments to extend the transmission network. Without adequate transmission capacity, HPP operation can be constrained such that the services offered by the plant are less than what it could offer in an unconstrained system.

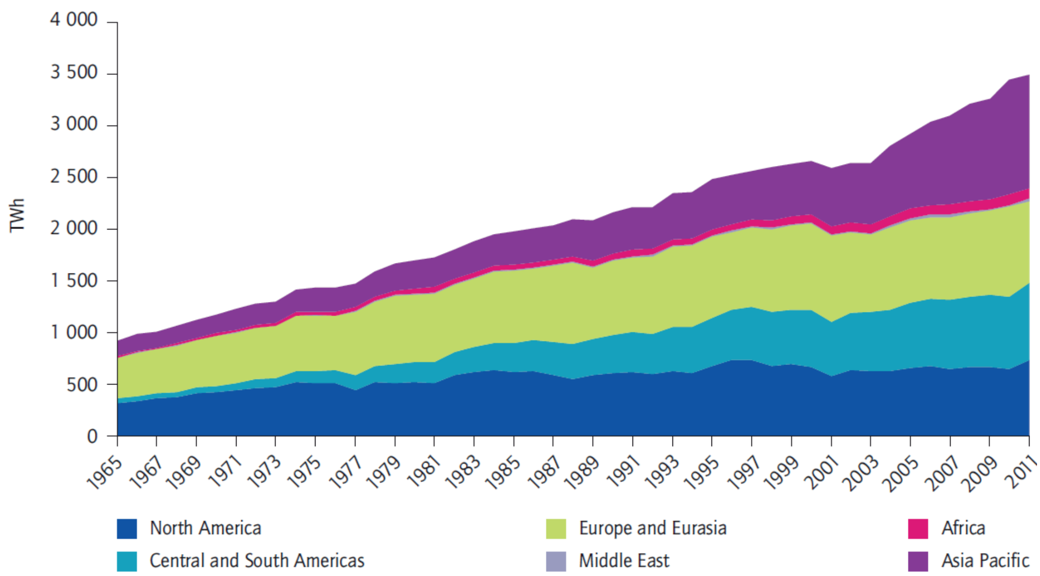
Some key findings from Technology Roadmap: Hydropower, IEA 2012 [52]:

- Hydroelectricity presents several advantages over most other sources of electrical power, including a high level of reliability, proven technology, high efficiency, very low operating and maintenance costs, flexibility and large storage capacity.
- Hydropower is the major renewable electricity generation technology worldwide and will remain so for a long time. Since 2005, new capacity additions in hydropower have generated more electricity than all other renewables combined.
- The potential for additional hydropower remains considerable, especially in Africa, Asia and Latin America. This roadmap foresees, by 2050, a doubling of global capacity up to almost 2 000 GW and of global electricity generation over 7 000 TWh. Pumped storage hydropower capacities would be multiplied by a factor of 3 to 5.
- Most of the growth in hydroelectricity generation will come from large projects in emerging economies and developing countries. In these countries, large and small hydropower projects can improve access to modern energy services and alleviate poverty, and foster social and economic development, especially for local communities. In industrialized countries, upgrading or redevelopment of existing plants can deliver additional benefits.
- Hydropower reservoirs can also regulate water flows for freshwater supply, flood control, irrigation, navigation services and recreation. Regulation of water flow may be important to climate change adaptation.
- Both reservoir and pumped storage hydropower are flexible sources of electricity that can help system operators handle the variability of other renewable energy such as wind power and photovoltaic electricity.
- In order to achieve its considerable potential for increasing energy security while reducing reliance on electricity from fossil fuels, hydropower must overcome barriers relative to policy, environment, public acceptance, market design and financial challenges.
- Large or small, associated with a reservoir or run-of-river, hydropower projects must be designed and operated to mitigate or compensate impacts on the environment and local populations. The hydropower industry has developed a variety of tools, guidelines and protocols to help developers and operators address the environmental and social issues in a satisfactory manner.
- New turbines and design make modern hydropower plants more sustainable and environmentally friendly; better management helps avoid damage to downstream ecosystems.

- Hydropower projects require very substantial up-front investment, which can range up to tens of billion USD. Although hydropower is the least-cost renewable electricity technology and is usually competitive with all alternatives, financing remains a key issue. This roadmap calls for innovative financing schemes and market design reforms to ensure adequate long-term revenue flows and reduced risks for investors.

Table B4-2 Top ten hydropower producers in 2010 [52]

Country	Hydro electricity (TWh)	Share of electricity generation (%)
China	694	14.8
Brazil	403	80.2
Canada	376	62.0
United States	328	7.6
Russia	165	15.7
India	132	13.1
Norway	122	95.3
Japan	85	7.8
Venezuela	84	68
Sweden	67	42.2



Sources: BP, 2012 and IEA analysis.

Figure B4-1 Hydroelectricity generation, 1965-2011 [52]

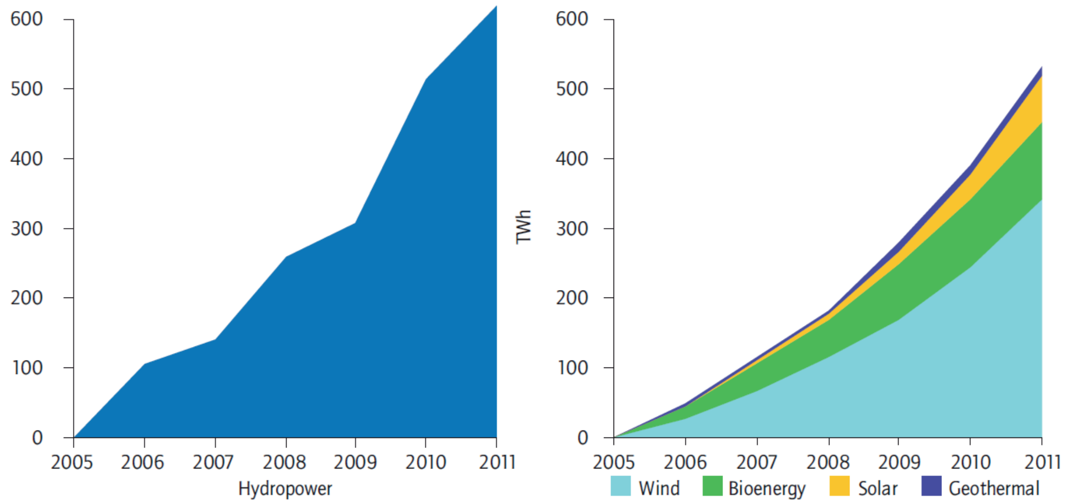


Figure B4-2 Electricity generation from recent additions to hydropower (left) and other renewables (right) [52]

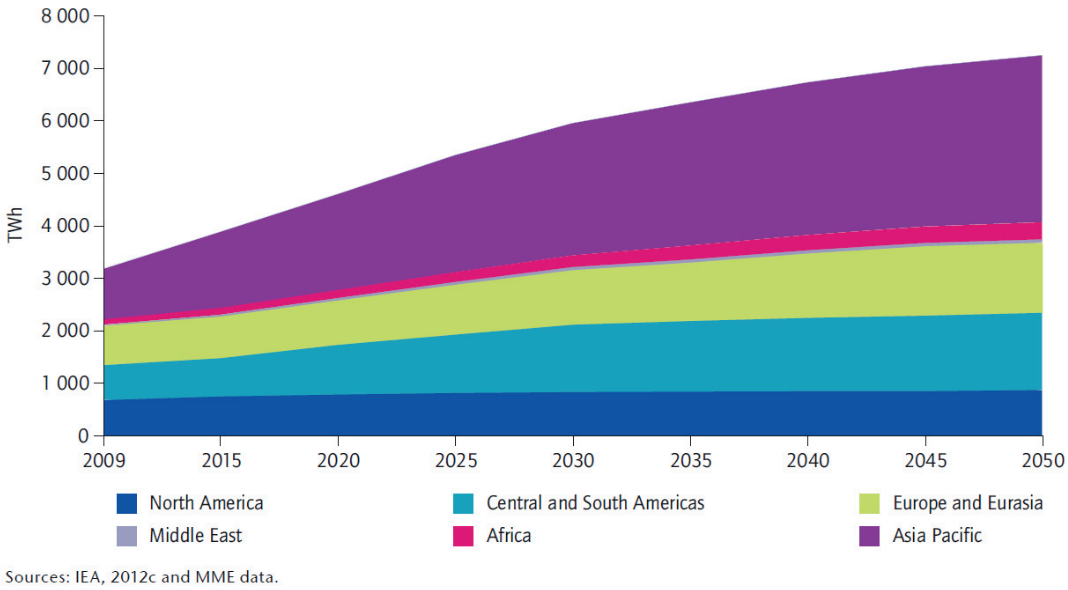


Figure B4-3 Hydroelectricity generation till 2050 in the Hydropower Roadmap vision (TWh) [52]

Hydropower in Norway:
In 2014 there were about 1,500 small and large hydropower plants in Norway, which together are generating about 130 TWh annually on average. The installed capacities in the power plants are ranging from just a few

hundred kW to more than 1,200 MW. Total hydropower production capacity in Norway was 30,960 MW as of January 2014.

The total theoretical potential for exploitation of hydropower in Norway is estimated to about 600 TWh/year. Due to economic and environmental considerations, this whole potential is not possible to exploit. The total technical/economic hydropower potential in Norway was in the beginning of 2014 estimated at 214 TWh/year, assuming an upper investment limit for new generation of 4-5 NOK/kWh. 51 TWh of this total potential is in protected areas and is not available for development. This means that it remains a real potential of 32 TWh/year for new hydropower generation. This is illustrated in Figure B4-4 [28].

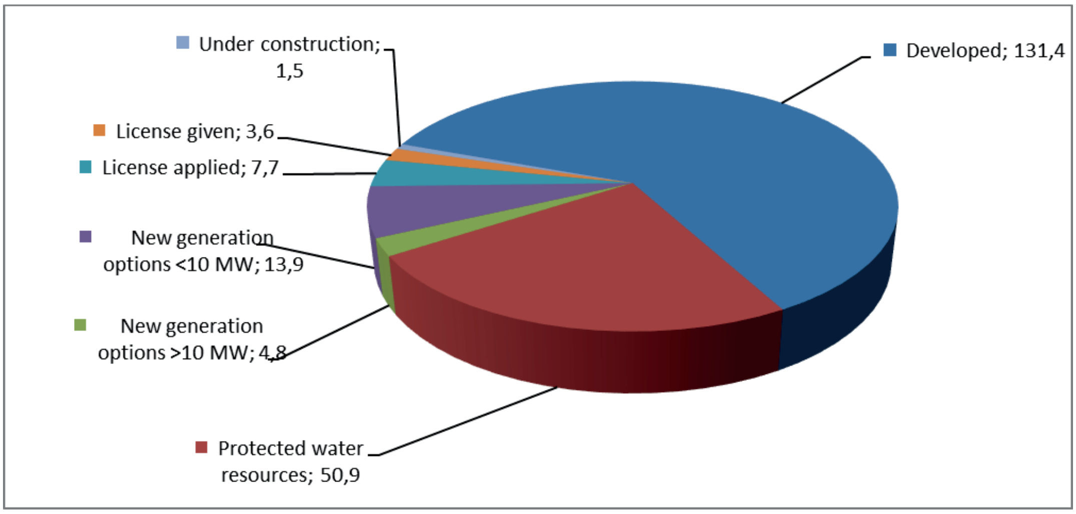


Figure B4-4 Total hydropower potential in Norway as of 01.01.2014 (mean annual production in TWh)

In 2013 the hydropower production in Norway was 129.0 TWh. This is 96.1% of the total electric power production in Norway the same year. The gross consumption of electric energy in Norway 2013 was 129.2 TWh (including electric boilers and losses). This means that nearly 100% of the gross consumption of electric energy in Norway is covered by hydropower production.

B.5. Ocean energy

Ocean energy offers the potential for long-term carbon emissions reduction but is unlikely to make a significant short-term contribution before 2020 due to its nascent stage of development. The theoretical potential of 2,056,000 TWh/yr contained in the world's oceans easily exceeds present human energy requirements. Government policies are contributing to accelerate the deployment of ocean energy technologies, heightening expectations that rapid progress may be possible. The six main classes of ocean energy technology offer a diversity of potential development pathways, and most offer potentially low environmental impacts as currently understood. There are encouraging signs that the investment cost of ocean energy technologies and the leveled cost of electricity generated will decline from their present non-competitive levels as R&D and demonstrations proceed, and as deployment occurs. Whether these cost reductions are sufficient to enable broad-scale deployment of ocean energy is the most critical uncertainty in assessing the future role of ocean energy in mitigating climate change.

Ocean energy can be defined as energy derived from technologies that utilize seawater as their motive power or harness the water's chemical or heat potential. The RE resource in the ocean comes from six distinct sources, each with different origins and each requiring different technologies for conversion. These sources are:

Wave energy derived from the transfer of the kinetic energy of the wind to the upper surface of the ocean. The total theoretical wave energy resource is 32,000 TWh/yr, but the technical potential is likely to be substantially less and will depend on development of wave energy technologies.

Tidal range (tidal rise and fall) derived from gravitational forces of the Earth-Moon-Sun system. The world's theoretical tidal power potential is in the range of 1 to 3 TW, located in relatively shallow waters. Again, technical potential is likely to be significantly less than theoretical potential.

Tidal currents derived from water flow as a result from the filling and emptying of coastal regions associated with tides. Current regional estimates of tidal current technical potential include 48 TWh/yr for Europe and 30 TWh/yr for China. Commercially attractive sites have also been identified in the Republic of Korea, Canada, Japan, the Philippines, New Zealand and South America.

Ocean currents derived from wind-driven and thermohaline ocean circulation. The best-characterized system of ocean currents is the Gulf Stream in North America, where the Florida Current has a technical potential for 25 GW of electricity capacity. Other regions with potentially promising ocean circulation include the Agulhas/Mozambique Currents off South Africa, the Kuroshio Current off East Asia and the East Australian Current.

Ocean thermal energy conversion (OTEC) derived from temperature differences arising from solar energy stored as heat in upper ocean layers and colder seawater, generally below 1,000 m. Although the energy density of OTEC is relatively low, the overall resource potential is much larger than for other forms of ocean energy. One 2007 study estimates that about 44,000 TWh/yr of steady-state power may be possible.

Salinity gradients (osmotic power) derived from salinity differences between fresh and ocean water at river mouths. The theoretical potential of salinity gradients is estimated at 1,650 TWh/yr.

Ocean energy in Norway:
Wave energy:
According to a public Norwegian report from 1998 about the energy and power balance towards 2020 [53], the wave energy represent in average 20-40 kW/m wave front in the sea off the Norwegian coast. The average wave energy is at least twice as high in the winter as in the summer. The inflow of wave energy towards the Norwegian coast is estimated at 400 TWh/year.

Utilization of wave energy is still at an early stage. Wave energy can be competitive without government support in certain niches, such as operation of navigational beacons, fish breeding, seawater desalination and power supplies to isolated coastal communities where only expensive electricity from diesel generators are available.

Tidewater energy:
The tidal difference is greatest in the northern Norway with a mean tidal range of about 2 meters. It is estimated a theoretical potential in Norway at about 1-2 TWh/year.

Tidewater is still a little used energy source in Norway, but some test constructions are established using tidal turbines.

B.6. Wind energy

Wind energy has been used for millennia in a wide range of applications. The use of wind energy to generate electricity on a commercial scale, however, became viable only in the 1970s as a result of technical advances and government support. A number of different wind energy technologies are available across a range of applications, but the primary use of wind energy of relevance to climate change mitigation is to generate electricity from larger, grid-connected wind turbines, deployed either on land ('onshore') or in sea- or freshwater ('offshore'). Smaller facilities connected to the distribution grid is not so normal.

Wind energy offers significant potential for near-term (2020) and long-term (2050) GHG emissions reductions. The wind power capacity installed by the end of 2009 was capable of meeting roughly 1.8% of worldwide electricity demand, and that contribution could grow to in excess of 20% by 2050 if ambitious efforts are made to reduce GHG emissions and to address other impediments to increased wind energy deployment. Onshore wind energy is already being deployed at a rapid pace in many countries, and no insurmountable technical barriers exist that preclude increased levels of wind energy penetration into electricity supply systems. Moreover, though average wind speeds vary considerably by location, ample technical potential exists in most regions of the world to enable significant wind energy deployment. In some areas with good wind resources, the cost of wind energy is already competitive with current energy market prices, even without considering relative environmental impacts. Nonetheless, in most regions of the world, policy measures are still required to ensure rapid deployment. Continued advancements in on- and offshore wind energy technology are expected, however, further reducing the cost of wind energy and improving wind energy's GHG emissions reduction potential.

The global technical potential for wind energy is not fixed, but is instead related to the status of the technology and assumptions made regarding other constraints to wind energy development. Nonetheless, a growing number of global wind resource assessments have demonstrated that the world's technical potential exceeds current global electricity production.

No standardized approach has been developed to estimate the global technical potential of wind energy: the diversity in data, methods, assumptions, and even definitions for technical potential complicate comparisons. The AR4 identified the technical potential for onshore wind energy as 50,000 TWh/yr. Other estimates of the global technical potential for wind energy that consider relatively more development constraints range from a low of 19,400 TWh/yr (onshore only) to a high of 125,000 TWh/yr (on- and near-shore). This range corresponds to roughly one to six times global electricity production in 2008, and may understate the technical potential due to several of the studies relying on outdated assumptions, the exclusion or only partial inclusion of offshore wind energy in some of the studies, and methodological and computing limitations. Estimates of the technical potential for offshore wind energy alone range from 4,000 to 37,000 TWh/yr when only considering relatively shallower and near-shore applications; greater technical potential is available if also considering deeper-water applications that might rely on floating wind turbine designs.

Regardless of whether existing estimates under- or overstate the technical potential for wind energy, and although further advances in wind resource assessment methods are needed, it is evident that the technical potential of the resource itself is unlikely to be a limiting factor for global wind energy deployment. Instead, economic constraints associated with the cost of wind energy, institutional constraints and costs associated with transmission access and operational integration, and issues associated with social acceptance and environmental impacts are likely to restrict growth well before any absolute limit to the global technical potential is encountered.

In addition, ample technical potential exists in most regions of the world to enable significant wind energy deployment. The wind resource is not evenly distributed across the globe nor uniformly located near population centers, however, and wind energy will therefore not contribute equally in meeting the needs of every country. The technical potentials for onshore wind energy in OECD North America and Eastern Europe/Eurasia are found to be particularly sizable, whereas some areas of non-OECD Asia and OECD Europe appear to have more limited onshore technical potential. Recent, detailed regional assessments have generally found the size of the wind resource to be greater than estimated in previous assessments.

Global climate change may alter the geographic distribution and/or the inter- and intra-annual variability of the wind resource, and/or the quality of the wind resource, and/or the prevalence of extreme weather events that may impact wind turbine design and operation. Research to date suggests that it is unlikely that multi-year annual mean wind speeds will change by more than a maximum of ±25% over most of Europe and North America during the present century, while research covering northern Europe suggests that multi-year annual mean wind power densities will likely remain within ±50% of current values. Fewer studies have been conducted for other regions of the world. Though research in this field is nascent and additional study is warranted, research to date suggests that global climate change may alter the geographic distribution of the wind resource, but that those effects are unlikely to be of a magnitude to greatly impact the global potential for wind energy deployment.

Some key findings from Technology Roadmap: Wind energy, IEA 2013 [54]:

- Since 2008, wind power deployment has more than doubled, approaching 300 gigawatts (GW) of cumulative installed capacities, led by China (75 GW), the United States (60 GW) and Germany (31 GW). Wind power now provides 2.5% of global electricity demand – and up to 30% in Denmark, 20% in Portugal and 18% in Spain. Policy support has been instrumental in stimulating this tremendous growth.
- Progress over the past five years has boosted energy yields (especially in low-wind-resource sites) and reduced operation and maintenance (O&M) costs. Land-based wind power generation costs range from USD 60 per megawatt hour (USD/MWh) to USD 130/ MWh at most sites. It can already be competitive where wind resources are strong and financing conditions are favourable, but still requires support in most countries. Offshore wind technology costs levelled off after a decade-long increase, but are still higher than land-based costs.
- The geographical pattern of deployment is rapidly changing. While countries belonging to the Organisation for Economic Co-operation and Development (OECD) led early wind development, from 2010 non-OECD countries installed more wind turbines. After 2030, non-OECD countries will have more than 50% of global installed capacity.
    - While there are no fundamental barriers to achieving – or exceeding – these goals, several obstacles could delay progress including costs, grid integration issues and permitting difficulties.
    - This roadmap assumes the cost of energy from wind will decrease by as much as 25% for land-based and 45% for offshore by 2050 on the back of strong research and development (R&D) to improve design, materials, manufacturing technology and reliability, to optimize performance and to reduce uncertainties for plant output. To date, wind power has received only 2% of public energy R&D funding: greater investment is needed to achieve wind's full potential.
    - As long as markets do not reflect climate change and other environmental externalities, accompanying the cost of wind energy to competitive levels will need transitional policy support mechanisms.
    - To achieve high penetrations of variable wind power without diminishing system reliability, improvements are needed in grid infrastructure and in the flexibility of power systems as well as in the design of electricity markets.
    - To engage public support for wind, improved techniques are required to assess, minimize and mitigate social and environmental impacts and risks. Also, more vigorous communication is needed on the value of wind energy and the role of transmission in meeting climate targets and in protecting water, air and soil quality.

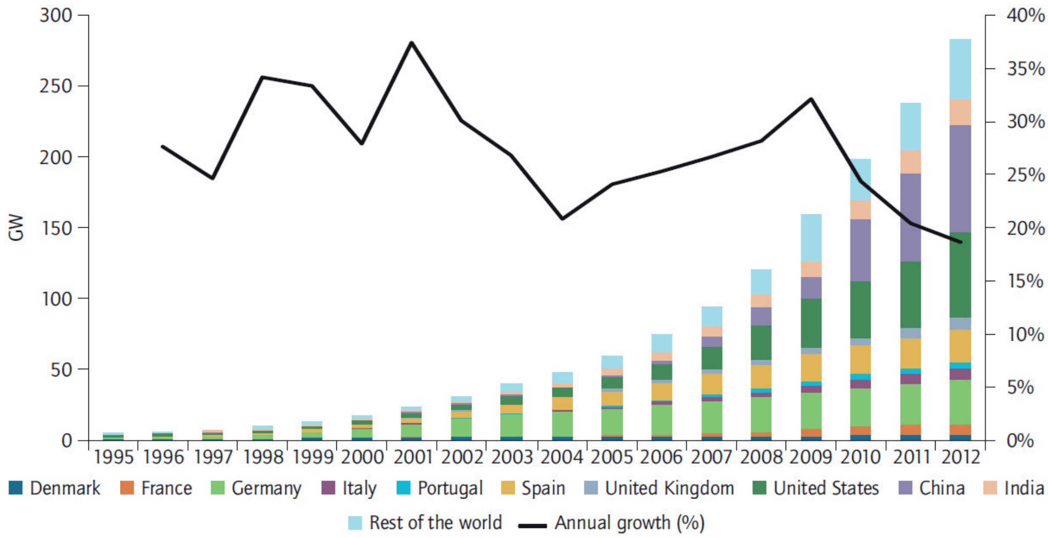


Figure B6-1 Global cumulative growth of wind power capacity [54]

One scenario in the roadmap [54] sees energy systems radically transformed to achieve the goal of limiting global mean temperature increase to 2°C (the 2 °C Scenario [**2DS**]). A second scenario, the High Renewables Scenario (**hiRen** Scenario), achieves the target with a larger share of renewables, which requires faster and stronger deployment of wind power to compensate for the assumed slower progress in the development of CCS[24] and deployment of nuclear than in 2DS. This hiRen Scenario is more challenging for renewables in the electricity sector. Figure B6-2 compares regional production of wind electricity in these two scenarios.

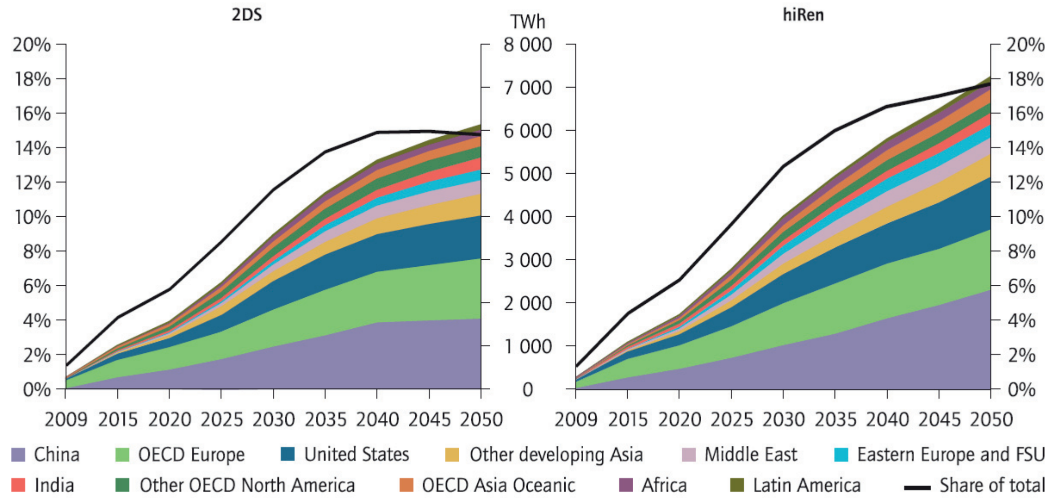


Figure B6-2 Regional production of wind electricity in the 2DS and hiRen scenarios [54]

Wind energy in Norway:

[24] CCS – Carbon capture and storage

In Norway as in the rest of northern Europe and North America, the wind is usually heavier in winter than in summer. This is beneficial for the utilization of wind as an energy resource in Norway since electricity consumption also is higher in winter than summer. Norway's high proportion of flexible hydropower is also an advantage together with the uncontrollable wind power as hydropower production can be increased and decreased depending on the wind power production.

Good and stable wind conditions are favorable for wind power production. Simultaneously, high winds may cause that the wind turbines must be stopped. Icing and complex terrain may also affect the production.

Norway has excellent wind resources. The average wind speed over the year for large parts of the coast and several locations in the hinterland can be 7-9 m/s 80 meters above the ground. In places with local acceleration (ridges and hills) the wind speed can be over 9 m/s, but many places complex terrain will slow the wind and create turbulence.

Wind turbines produced 1,6 TWh or 1.1 % of the Norwegian electricity generation in 2012 [29]. The potential for wind power generation in Norway is estimated to 250 TWh/year [30], but only a small part of this is possible to realize in near future. Almost 70% of the estimated resources are located in Finnmark, the northernmost county in Norway. Low consumption of electric energy within the county combined with very long distances to consumption centers further south makes it unlikely to ever utilize more than just a fraction of the estimated wind potential.

APPENDIX C – Smart grid architecture

As the result of the mandated work requested through the M/490 mandate [32], working groups of the CEN-CENELEC-ETSI Smart Grid Coordination Group have compiled and published several reports regarding standards, methods, models, tools, interoperability and information security for Smart Grids.

The power system will undergo fundamental changes during the coming years. To support this transition in a consistent way, a generic European conceptual model is defined [55], and is to be regarded as the starting point for all modelling activities, and for all other models, frameworks, and architectures, which are used to arrive at standards required for Smart Grids and smart markets.

C.1. The European Conceptual Model

The conceptual model aims to highlight the key areas of attention from the point of view of responsibility (refer to Figure C1-1). The model consists of four main conceptual domains: *Operations*, *Grid Users, Markets, and Energy Services*. Each of these conceptual domains contains one or more subdomains which group market roles from the European electricity market. To support its recognition, the *Operations* and *Grid Users* conceptual domains also show some well-known system actors that are present in those domains.

While this model is based on the electricity market structures of the EU member states, their roles and responsibilities are cleanly defined and provide a solid basis; new parties may enter certain markets, responsibilities may be redistributed, but the fundamental roles and their respective responsibilities are expected to remain constant.

Operations and *Grid Users* are conceptual domains that are directly involved in the physical processes of the power system: electricity generation, transport/distribution and electricity usage. In addition, these domains include (embedded) ICT enabled system actors. The *Markets* and *Energy Services* conceptual domains are defined by roles and actors and their activities in trade of electricity products and services (markets), and the participation in the processes of trade and system operations representing grid users (energy services).

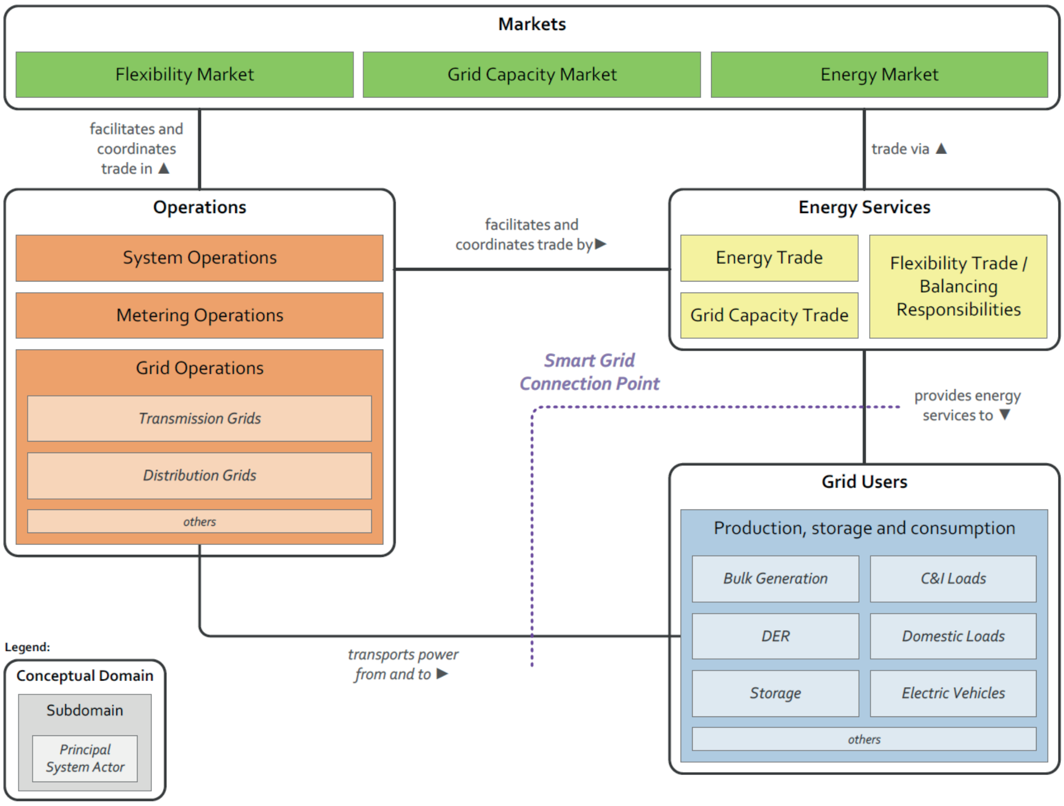


Figure C1-1 European Conceptual Model for the Smart Grid [55].

The ***Operations*** conceptual domain is defined by market roles and actors related to the stable and safe operations of the power system. The domain ensures the usage of the grid is within its operational constraints and facilitates the activities in the market. Actors in this domain may use services from the market to fulfill these responsibilities. *Grid Operations*, *System Operations* and *Metering Operations* are identified as sub-domains in the *Operations* conceptual domain. System actors in this domain include grid assets such as transformers, switchgear, distribution management systems (DMS), energy management systems (EMS), etc. in *Transmission* and *Distribution Grids*, micro grid management systems, metering systems, control center systems, etc.

Table C1-1 Typical roles in the Operations conceptual domain [55]

Subdomain	Harmonized role
System Operations	System Operator, Control Area Operator, Control Block Operator, Coordination Center Operator, Imbalance Settlement Responsible, Reconciliation Responsible
Metering Operations	Meter Administrator, Meter Operator, Metering Point Administrator, Metered Data Aggregator, Metered Data Collector, Metered Data Responsible
Grid Operations	Grid Operator, Grid Access Provider

The ***Grid Users*** conceptual domain is defined by market roles and actors involved in the generation, usage and possibly storage of electricity; from bulk generation and commercial and industrial loads down to distributed energy resources, domestic loads, etc. The market roles and actors in this domain use the grid to transmit and distribute power from generation to the loads. Apart from market roles related to the generation, load and storage assets, the *Grid Users* conceptual domain includes system actors such as (customer) energy management and process control systems. Grid users provide also flexibility, as they become an active participant of the energy system.

Table C1-2 Roles in the Grid Users conceptual domain [55]

Subdomain	Harmonized role
Production, storage and consumption	Party Connected to the Grid, Consumer, Producer

The ***Energy Services*** conceptual domain is defined by market roles and actors involved in providing energy services to the *Grid Users* conceptual domain. These services include balancing & trading in the electricity generated, used or stored by the *Grid Users* domain, and ensuring that the activities in the Grid Users domain are coordinated in e.g. the system balancing mechanisms and customer information services (CIS) systems.

Through the *Energy Services* conceptual domain the *Grid Users* conceptual domain is connected to activities such as trade and system balancing. From the *Grid Users* domain, flexibility in power supply and demand is provided. This flexibility is used for system balancing (through e.g. ancillary services, demand response, etc.) and trading on the market. Also roles are included which are related to trade in grid capacity (as currently is traded on the transmission level).

The roles and actors from the *Energy Services* conceptual domain facilitate participation in the electricity system, by representing the *Grid Users* conceptual domain in operations (e.g. balance responsibility) and markets (trading).

Table C1-3 Roles in the Energy Services conceptual domain [55]

Subdomain	Harmonized role
Energy Trade	Balance Supplier, Block Energy Trader, Reconciliation Accountable
Grid Capacity Trade	Capacity Trader, Interconnection Trade Responsible
Flexibility Trade / Balancing Responsibilities	Balance Responsible Party, Consumption Responsible Party, Production Responsible Party, Trade Responsible Party, Scheduling Coordinator, Resource Provider

The ***Markets*** conceptual domain is defined by the market roles and actors that support the trade in electricity (e.g. on day ahead power exchanges) and other electricity products (e.g. grid capacity, ancillary services). It is reflecting the market operations possible along the energy conversion chain, e.g. energy trading, mass market, retail market. Sub domains which are identified in this domain are: *Energy Market* (e.g. commodity market), *Grid Capacity Market* (e.g. Transmission capacity market), and *Flexibility Market* (e.g. Imbalance market). Activities in the *Market* domain are coordinated by the *Operations* domain to ensure the stable and safe operation of the power system.

Table C1-4 Roles in the Markets conceptual domain [55]

Subdomain	Harmonized role
Flexibility Market	Reserve Allocator, Merit Order List Responsible
Grid Capacity Market	Capacity Coordinator, Transmission Capacity Allocator, Nomination Validator
Energy Market	Market Information Aggregator, Market Operator

Information and energy flows between the four conceptual domains: *Operations*, *Grid Users, Markets* and *Energy Services*. If the domains shall work together and function as intended, the different elements in the chain must to be interoperable. Interoperability is a key issue for the Smart Grid. Most technologies in the future Smart Grid are known today, but the challenge is their integration.

C.2. Interoperability

CEN-CENELEC-ETSI Smart Grid Coordination Group defines interoperability (IOP) in [56] as:
"**Interoperability**: The ability of two or more networks, systems, devices, applications, or components to interwork, to exchange and use information in order to perform required functions."

Figure C2-1 from [56] illustrates the concept:

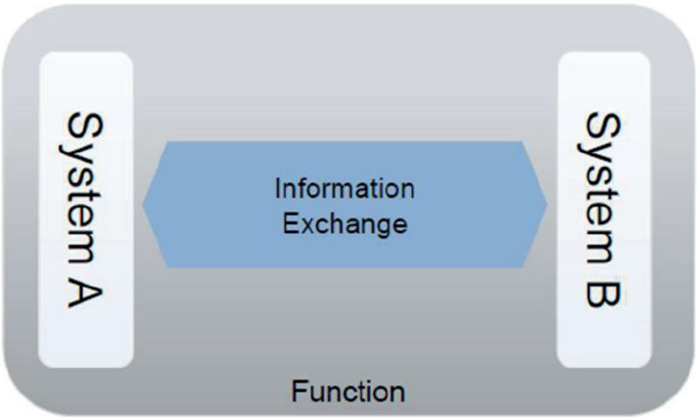


Figure C2-1 Interoperable systems performing a function [56]

As more and more ICT components are connected to the physical electrical infrastructure, interoperability is a key requirement for a robust, reliable and secure Smart Grid infrastructure. System *conformance* or *compatibility* is not enough for this goal. The extensive disruption of the power system in North America in august 2003 is one example of this. Components and systems cannot work alone, but need to work together.

Interoperability does not need to result in *interchangeability* for several reasons; the hardware and electrical footprint required for interchangeability may be at odds with the performance, configuration and capacity requirements for technological development. Whilst interoperability may be possible or enhanced, interchangeability may be lost.

Subject to regulatory requirements and business needs, it is generally sufficient to have interoperability, rather than interchangeability. However in certain situations, there may be a need for interchangeability e.g. with respect to emergency preparedness.

Interchangeability is the ability of two or more devices or components to be interchanged without making changes to other devices or components in the same system and without degradation in system performance. The two devices do not communicate with each other, but one can simply be replaced by another – so interchangeability is not concerned with interoperability.

Conformance means that the implementation of a product, process or service, is in accordance with the specified standards or authority. In the interests of IOP where a standard is written it is helpful that it allows conformance to its requirements to be assessed:

- It describes the function and behavior of the product, rather than its design.
- It gives precise, measurable specifications.
- It mandates reliable and reproducible tests and methods.

Conformance may be assessed against a national or regional standard, or in fact against any specification. Conformance with standards raises the possibility of Interoperability, but does not guarantee this by any means.

Compatibility is concerned with the ability of two or more systems or components to perform their required functions with no modification or conversion required, while sharing the same environment (according IEEE 610). Two components (or systems) can also be compatible, but perform completely separate functions. They do not need to communicate with each other, but simply be resident on the same environment – so compatibility is not concerned with interoperability.

C.3. Interoperability in the Smart Grid: The SGAM model [56], [57]

The Smart Grid as a system exhibits a high complexity regarding organizational and technological aspects. Various actors take part in the planning and construction of the system representing several organizations and engineering domains. Therefore, a key challenge of the Smart Grid is integration, affecting components for generation, transportation, distribution, storage, and consumption of electrical energy and the supporting information systems and applications.

To create the Smart Grid as an operational system-of-systems, the functionalities and interfaces of its components must be specified beforehand. As requirements serve as the decisive factor for all further engineering activities, a suitable methodology for requirements specification and management is essential. This ensures traceability between design decisions and system requirements, supports collaboration between stakeholders by assigning responsibilities, allows the structure of the system regarding software and hardware to be derived and enables the implementation to be tested against the specification.

Following the definition given in 4.2.2, interoperability represents an essential requirement for the Smart Grid since it is supposed to integrate different assets and applications into one functional system. In order to support the elicitation and management of requirements, a suitable structure should be used.

The Smart Grid Architecture Model (SGAM) [57] is a reference model to analyze and visualize smart grid use cases in a technology-neutral manner. Furthermore, it supports comparison of different approaches to Smart Grid solutions so that differences and commonalities between various paradigms, roadmaps, and viewpoints can be identified. By supporting the principles of universality, localization, consistency, flexibility and interoperability, it also provides a systematic approach to cope with the complexity of smart grids, allowing a representation of the current state of implementations in the electrical grid as well as the evolution to future smart grid scenarios.

The SGAM builds on proven approaches from power systems as well as interdisciplinary fields like systems engineering and combines them in a simple but comprehensive model. The work on the SGAM is specifically based on significant existing material such as the NIST Conceptual Model [NIST 2009], the GridWise Architecture Council Stack interoperability categories [GWAC 2008], the IntelliGrid Methodology [IEC PAS 62559:2008-01], the European Conceptual Model and architecture standards like TOGAF and Archimate.

Power system management distinguishes between electrical process and information management. These viewpoints can be partitioned into the physical domains of the electrical energy conversion chain and the hierarchical zones for management of the electrical process (refer to [IEC 62357-1:2012, IEC 62264:2003]). The *Smart Grid Plane* spans in one dimension the complete electrical energy conversion chain, partitioned into five domains: (Bulk) Generation, Transmission, Distribution, DER and Customer Premises. And in the other dimension the hierarchical levels of power system management, partitioned into six zones: Process, Field, Station, Operation, Enterprise and Market. This smart grid plane enables the representation of the zones in which power system management interactions between domains or inside a single domain take place.

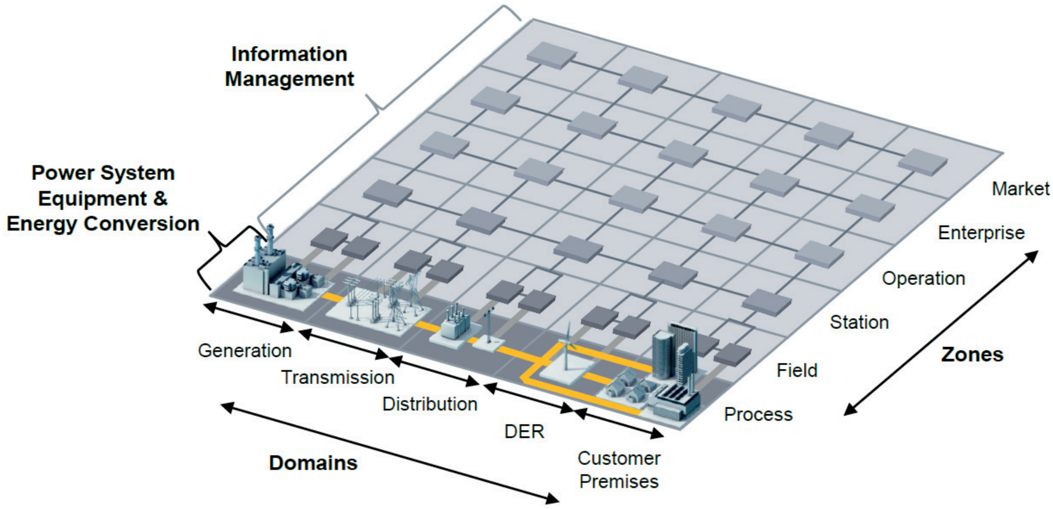


Figure C3-1 Smart Grid Plane - Domains & zones og SGAM [57]

The *Smart Grid Plane* covers the complete electrical energy conversion chain. This includes the domains listed in Table C3-1.

Table C3-1 SGAM domains [57]

Domain	Description
(Bulk) Generation	Representing generation of electrical energy in bulk quantities typically connected to the transmission system, such as by fossil, nuclear and hydro power plants, off-shore wind farms, large scale solar power plant (i.e. PV, CSP).
Transmission	Representing the infrastructure which transports electricity over long distances.
Distribution	Representing the infrastructure which distributes electricity to customers.
DER	Representing distributed electrical resources directly connected to the public distribution grid, applying small-scale power generation and consumption technologies (typically in the range of 3 kW to 10,000 kW). These distributed electrical resources may be directly controlled by e.g. a TSO, DSO, an aggregator or Balance Responsible Party (BRP).
Customer Premises	Hosting both end users of electricity and also local producers of electricity. The premises include industrial, commercial and home facilities (e.g. chemical plants, airports, harbors, shopping centers, homes). Also generation in form of e.g. photovoltaic generation, electric vehicles storage, batteries, micro turbines.

The SGAM zones represent the hierarchical levels of power system management [IEC 62357-1:2012]. These zones reflect a hierarchical model that considers the concept of aggregation and functional separation in power system management. The SGAM zones are described in Table C3-2.

Table C3-2 SGAM zones [57]

Zone	Description
Process	Including the physical, chemical or spatial transformations of energy (electricity, solar, heat, water, wind …) and the physical equipment directly involved (e.g. generators, transformers, circuit breakers, overhead lines, cables, electrical loads, any kind of sensors and actuators which are part or directly connected to the process,…).
Field	Including equipment to protect, control and monitor the process of the power system, e.g. protection relays, bay controller, any kind of intelligent electronic devices which acquire and use process data from the power system.
Station	Representing the areal aggregation level for field level, e.g. for data concentration, functional aggregation, substation automation, local SCADA systems, plant supervision…
Operation	Hosting power system control operation in the respective domain, e.g. distribution management systems (DMS), energy management systems (EMS) in generation and transmission systems, microgrid management systems, virtual power plant management systems (aggregating several DER), electric vehicle (EV) fleet charging management systems.
Enterprise	Including commercial and organizational processes, services and infrastructures for enterprises (utilities, service providers, energy traders …), e.g. asset management, logistics, work force management, staff training, customer relation management, billing and procurement…
Market	Reflecting the market operations possible along the energy conversion chain, e.g. energy trading, retail market.

For interoperability between systems or components, the SGAM consists of five layers representing business objectives and processes, functions, information exchange and models, communication protocols and components. These five interoperability layers represent an abstract and condensed version of the interoperability categories introduced by the GridWise Architecture Council [GWAC2008].

Table C3-3 SGAM layers [57]

Layer	Description
Business	The business layer represents the business view on the information exchange related to smart grids. SGAM can be used to map regulatory and economic (market) structures (using harmonized roles and responsibilities) and policies, business models and use cases, business portfolios (products & services) of market parties involved. Also business capabilities, use cases and business processes can be represented in this layer.
Function	The function layer describes system use cases, functions and services including their relationships from an architectural viewpoint. The functions are represented independent from actors and physical implementations in applications, systems and components. The functions are derived by extracting the use case functionality that is independent from actors.
Information	The information layer describes the information that is being used and exchanged between functions, services and components. It contains information objects and the underlying canonical data models. These information objects and canonical data models represent the common semantics for functions and services in order to allow an interoperable information exchange via communication means.
Communication	The emphasis of the communication layer is to describe protocols and mechanisms for the interoperable exchange of information between components in the context of the underlying use case, function or service and related information objects or data models.
Component	The emphasis of the component layer is the physical distribution of all participating components in the smart grid context. This includes system & device actors, power system equipment (typically located at process and field level), protection and tele-control devices, network infrastructure (wired / wireless communication connections, routers, switches, servers) and any kind of computers.

Each layer covers the whole smart grid plane, which is spanned by electrical domains and information management zones.

- The SGAM framework is established by merging the concept of the interoperability layers with the previous introduced smart grid plane. This merging results in a model that spans three dimensions:
- SGAM domains
- Zones
- Interoperability layers

The complete three-dimensional representation of SGAM is depicted in Figure C3-2.

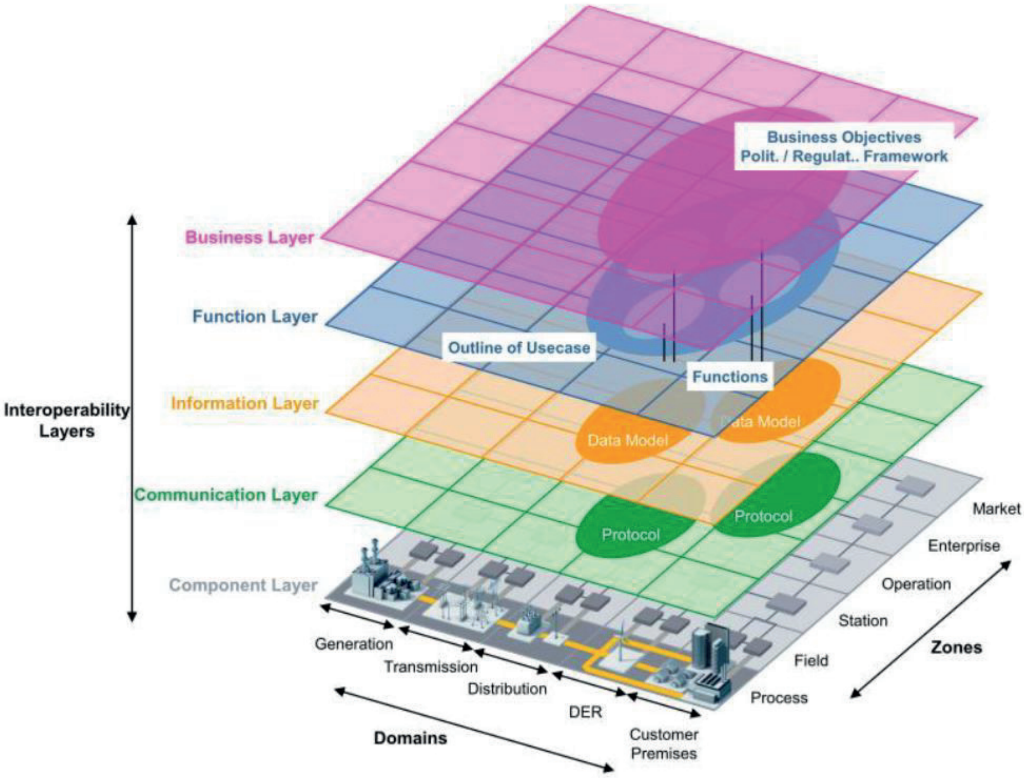


Figure C3-2 SGAM – Smart Grids Architecture Model [57]

Using the SGAM, Smart Grid use cases can be visualized and detailed and mapped to the layers of the model to test if a use case is supported by existing standards or to identify gaps in standardization. A use case analysis with the SGAM is based on the use case description. The different fields in the use case template provide the information for the analysis, e.g. the field *Domain(s)/Zone(s)* specifies directly how the use case maps onto the Smart Grid Plane. Furthermore, the actor list in the use case description provides - depending on the type of the actor - information on the roles involved to model the business layer in SGAM or information on the systems and devices involved to model the component layer.

For more information about the SGAM and use cases, see the CEN-CENELEC-ETSI report [57].