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Master Thesis Project

Impact of Future Residential Loads on Medium Voltage Networks

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Summary

Due to the transition towards a more sustainable energy supply, more decentralized electricity generation (e.g. solar, wind, combined heat and power) is connected to the low voltage and medium voltage grids. Another aspect of the energy transition, the expected electrification of mobility (electrical vehicles) and space heating (heat pumps), will result in a substantial additional load for the distribution grids. The future load (and generation) profiles of individual household consumers will differ more and be less predictable than nowadays. Existing residential load profiles will therefore no longer be sufficient for a reliable representation of the future electricity distribution needs. These future loads at the LV level (residential loads) will have a certain effect on the existing MV (distribution) networks. What the effect is and when the effect takes place depends on how different scenarios develop. The coupling of existing distribution grids with possible future loads resulting from different scenarios, is necessary to identify the impact on the existing grid. Which limitations will occur for different scenarios? Does the existing grids fulfil future needs?
The answers to the questions in the problem definition are of high importance for network planning, so Distribution System Operators (DSO) can adapt the networks in time, if necessary. The problem can be translated in an important research question:

"What is the impact of future residential loads on existing medium voltage networks, regarding network planning?"

Different scenarios, defined in some other research, are used to investigate the impact of future residential loads on the medium voltage network. The scenarios are based on different studies and governmental expectations (time span of 30 years, until 2040). A large set of MV networks of Enexis is analysed for this case study. Enexis is one of the largest DSOs of The Netherlands and owns a variety of MV (distribution) networks. The selected MV networks are available in network simulation files and include measurement values of existing loads. These simulation files cover the parts according to network topology from the 110/10kV- until the 10/0.4kV- transformer.

In order to identify the impact of residential loads on the MV network, network calculations are needed. Network analysis is done for network planning. Therefore, load-flow calculations will be applied, as these give insight into the steady-state behaviour of the power system. With these calculations the values of voltages, currents and power flows in the network are calculated. The existing residential loads in the network will be altered to future conditions. It is too exhaustive to manually adapt a large set of files, therefore a calculation tool is developed to alter all MV networks to future load conditions. This tool can also perform load-flow calculations for multiple networks at the same time.

The impact of future residential loads on the MV network for three different future scenarios (2040) have been analysed and identified. The results from the executed load-flow calculations applied to 50 MV networks of DSO Enexis show large differences in component loadings between the scenarios.

Scenario B causes the largest impact on component loadings, which is the result of a high demand: high penetrations of electrical vehicles and heat pumps, and a substantial rise in 'normal' demand (2% per year). Scenario A has a relative low impact (small demand growth) and results of Scenario C are in between (also caused by high penetrations of EVs and heat pumps, but in this scenario the rise in 'normal' demand is smaller).

Scenario B and C show large differences compared to the 1% growth scenario, the conventional network planning method. If this conventional method would still be applied, a large error in the expected overloads may resolve in an inefficient replacement strategy.

Most notable is the fact that in all scenarios the percentages of overloaded components can be significantly reduced by applying control to residential loads and generators.

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List of Abbreviations

LV	Low Voltage
MV	Medium Voltage
HV	High Voltage
CHP	Combined Heat and Power
DSO	Distribution System Operator
MV-D	Medium Voltage Distribution
MV-T	Medium Voltage Transmission
EV	Electric Vehicle
kV	Kilovolts
PL	Public Lighting
XLPE	*C*ross-Linked PolyEthylene
PILC	Paper Insulated Lead Covered
DG	Distributed Generation
VNF	Vision Network File
NOP	Normally Open Point

1 Introduction

1.1 Background information

Enexis, formerly Essent Netwerk, is the Distribution System Operator (DSO) that was hived off from Essent. Enexis is the independent network administrator in the Northern-East and Southern part of the Netherlands and is public owned. They are responsible for the construction, maintenance and management of the transport and distribution networks of electricity and gas in these regions. Enexis is the chain between the consumers of energy and the suppliers of energy.

The transition towards a more sustainable energy supply changes the demand and supply of energy and this has consequences for the grid which supports the transport of electricity generated and consumed. To prepare the medium and low voltage grid for the changes affecting them, they need to be adapted. The PhD research of Veldman contains further investigations of the changes, the effects of these on the grid and how the grid can cope with them [1].

"What are possible system concepts for future, reliable electricity distribution grids to manage them in a flexible and efficient way?"

To answer this question, Veldman divided the research in four stages:

- Stage 1: Identify future changes and gain insight in the existing grid
- Stage 2: Quantify the effects and impacts of future changes on the grids
- Stage 3: Identify the limitations of the existing grid
- Stage 4: Define possible solutions to address the issues identified in stage 3

The first stage is finished by Veldman. In the paper 'Smart grids put into practice: technical and regulatory aspects' [2] some of the observations made in this stage are described.

In the second stage the effects of the increase of distributed generation and changes on the demand side that have impact on the grid will be quantified. This stage started with a research on how residential load profiles change in the near future. The future changes are related to a changing demand and the application of new technologies, like solar cells, heat pumps, micro-CHP (Combined Heat and Power) and electrical vehicles. [3] gives an insight in the future residential loads and how the aggregated profile of a few households can be modelled. Due to changes at the residential level the load profile at the medium to low voltage transformer and at the medium voltage (MV) level will change, which is of interest for network planning. Further results have followed on how to model future residential load and generation at the MV level. Also, different future scenarios are determined for a representative view of the expected future loads in the network [4].

In the third stage possible scenarios of changes in supply and demand (as quantified in stage 2) are coupled to the grid to investigate the impact on the existing MV network. This stage is the framework of this master thesis project.

1.2 Problem definition

Until now electricity is for the largest part produced by large power plants which are connected to the high voltage (HV) grid, and inject large amounts of electricity. The electricity is flowing from the HV grids, through the MV grids, to the LV grids and the consumers connected to this voltage level (except for some heavy industries, connected to the MV and HV grids). The electricity is flowing one way from 'top' to 'bottom'.

Due to the transition to a more sustainable energy supply, decentralised electricity generation (solar cells, CHP systems, wind energy, etc.) inject electricity into the LV and MV (distribution) grids, and the direction of the energy flow can change. This can happen at the moment of little local electricity consumption and high decentralised production. Another part of the energy transition, the expected electrification of mobility (electrical vehicles) and residential heating (heat pumps), will result in a substantial additional load for the distribution grids. The additional generation and loads at the distribution grids will become variable in time, however consumers may still need to be fully supplied in the conventional way by the grid at moments of peak demand.

The future load (and generation) profiles of individual household consumers will differ more and be less predictable than nowadays [3]. Existing standard load profiles will therefore no longer be sufficient for a reliable representation of the future electricity distribution needs. These future loads at the LV level (residential loads) will have a certain effect on the existing MV (distribution) networks. What the effect is and when the effect takes place depends on how different scenarios develop. To investigate the impact of these developments, different scenarios are defined in [4]. The scenarios are based on different studies and governmental expectations (time span of 30 years, until 2040). The established scenarios contain information about different parameters (e.g. penetration degrees of future techniques depended on location and population density).

This coupling of existing distribution grids with possible future loads resulting from different scenarios, defined as stage 3, is necessary to identify the impact on the existing grid. Which limitations will occur for different scenarios? Does the existing grids fulfil future needs, and for how long?

1.3 Objectives and research question

Grid investments for network operators might be needed to cope with the effects of future loads on the grid. Extensions and upgrades to the grid in the future will be pressured due to an expected lack of engineers, caused by the ageing of personnel and a tight labour market. Together with the combination of the upcoming replacement wave of components and installations it becomes even more complex. The answers to the questions in the problem definition are of high importance for network planning, so DSO's can adapt the networks in time, if necessary. The problem can be translated in an important research question:

"What is the impact of future residential loads on existing medium voltage networks, regarding network planning?"

The main objective is to find out what the limitations/capabilities on the MV networks will be for different future scenarios which are defined in [4]. For each scenario a controlled (smart) and uncontrolled variant is studied. In the smart variant a part of the future loads and generators is controlled, e.g. using not time-critical loads like electric vehicles by applying smart charging. In this way, the capacity of the existing grid can be used for transferring extra electrical energy [5]. An objective is to investigate the difference in impact between controlled and uncontrolled scenarios.

The effects of future load profiles can influence the following aspects of the power grid and can result in bottlenecks:

- **(over)loadings of cables and transformers**
- **voltage deviations**
- **energy losses**
- power quality*
- short circuit currents*
- grounding and protection*
- power system stability*

Although all these aspects are important for the grid, specific requirements* in future grids, like power quality, protection and stability, will not be regarded in detail during this project. The focus for this research is on long-term network planning (and therefore on the steady state behaviour of the power system).

Already some research has been done on a few MV reference networks (of Enexis) with future loads [6]. This research, however, takes into account more detailed future loads and investigates the effect of future loads on a much larger set of existing MV-networks, covering a large area with different types of residential locations and population densities. In this way general conclusions about the effects on the (total) MV network of Enexis can be made. Furthermore, the conclusions may even be broader applicable, because developments in other countries are similar.

1.4 Approach

A large set of MV networks of Enexis will be analysed for this case study. Enexis, one of the largest DSOs of the Netherlands owns a variety of MV networks. The selected MV networks are available in network simulation files and include measurement values of existing loads. These simulation files cover the parts according by network topology from the 110/10kV- until the 10/0.4kV- transformer.

In order to identify the impact of residential loads on the MV network, network calculations are needed. The network analysis is done for network planning, therefore a load-flow calculation will be used, as it allows insight into the steady-state behaviour of the power system. With these calculations the values of voltages, currents and power flows in the network are calculated. The software *Vision Network Analysis* will be used to perform the load-flow calculations. Vision is an advanced tool for electric network analysis and is used for the planning, design and management of transmission, distribution and industrial networks.

The existing residential loads in the network will be altered to future conditions. The established scenarios provide needed information for this step (e.g. penetration degrees of future techniques depended on location and population density). These future parameters can be translated to aggregated load profiles by the techniques proposed in [3], which eventually results in input data for the network simulations. It is too exhaustive to manually adapt a large set of files, therefore a calculation tool will be developed to alter all MV networks to future load conditions. This tool will also include a manner (in combination with Vision) to perform the load-flow calculation for multiple networks at the same time.

Load-flow calculations for network planning is currently based on yearly peak values. In the conventional network the peak mostly occurs at the same time and the shape of aggregated residential load profiles of various residential areas are in general quite similar. Future load profiles may not have these properties [3] and in these cases not only peak values, but load profiles should be used for network calculations. The set of MV networks will be calculated for the maximum day (load) of the year with a 24 hours profile. The effects on voltage, component loading and losses for different scenarios will be analysed and a comparison will be made between controlled (smart) and uncontrolled scenarios. In figure 1.1 an overview is given of the stated research approach.

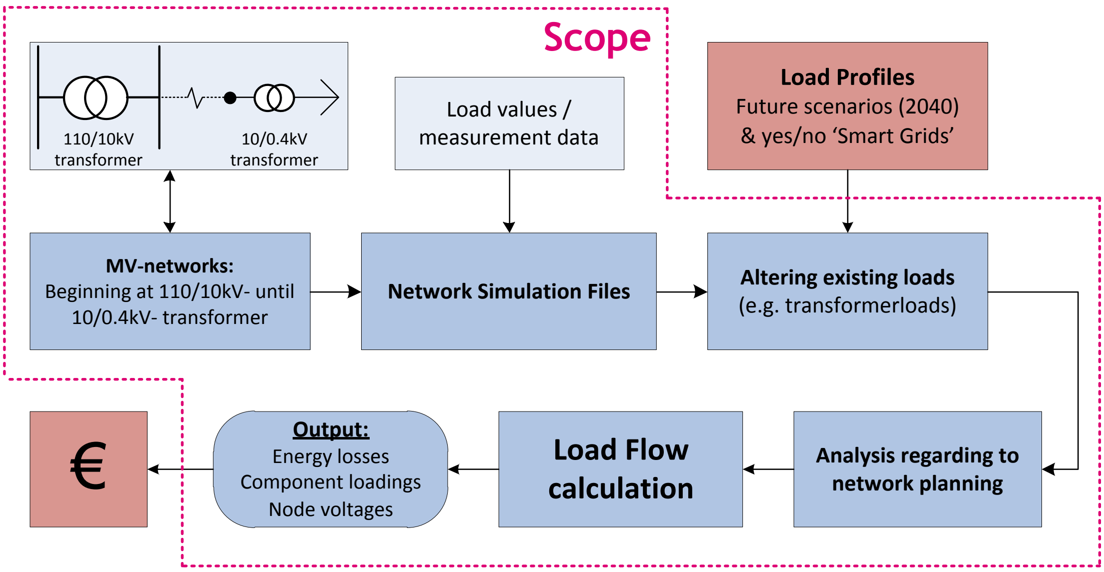

Fig 1.1: Schematic overview of the research approach

1.5 Constraints

1.5.1 *Inside the scope*

The project addresses the effect of future residential loads on a set of existing MV networks (owned by DSO Enexis) in the Netherlands. These networks cover the parts according by network topology from the 110/10kV- until the 10/0.4kV- transformer. This MV/LV transformer is the connection towards residential areas and will therefore function as a variable and input for the future residential loads. The impact of these future loads will be analysed regarding network planning which involve the steady state behaviour of a network. Technical aspects like voltage deviations, energy losses and component loadings will be analysed. The timeframe for the analysis will be the (load) situation over 30 years in 2040. The MV networks will be calculated (load-flow) with the use of software tool Vision Network Analyses for one day with 24hour load profiles.

1.5.2 *Outside the scope*

The establishment of future scenarios and residential load profiles are not part of this research. The scenarios defined in [4] and the future load profiles, for a part described in [3], are used for this.

Large concentrations of distributed generation (DG) connected to the MV network in the future will not be taken into account. These concentrations of DG (e.g. wind parks, CHPs in horticulture areas) are nowadays connected to new MV networks, sometimes even completely separated from consumers and connected on a higher MV level [10]. So these developments will not influence the existing MV networks.

Theoretically, the research can be extended to existing LV networks. However the number of networks which in this case should be analysed, will be very large. Besides, these networks are not digitally available like the corresponding set of MV networks for network calculations. The simulation of LV networks will be left out of the scope and the future (aggregated) residential loads will be projected on the MV/LV transformer as input.

Specific requirements in future grids, like power quality, protection and stability and short circuit currents will not be regarded during this research. The focus will be on the general system concepts, related to the load flow analysis.

The impact on MV installations and switch gear are also excluded from this research. The available data (simulation files of MV networks) don't contain sufficient information about the type of installations and for a determination of the power capabilities.

The output of this research, the effect of various scenarios and control strategies on the required capacities of the grid and on the energy losses, will be used for investment (cost analysis) and replacement options analysis. However, these analyses are not part of this research.

2 Medium Voltage Networks

This chapter discusses some important aspects related to (the design of) medium voltage networks, which might help to understand this report.

2.1 General overview of an electricity network

The main purpose of an electricity network is to connect the producers and consumers of electricity to each other. Over the last century evolved the concept that large power plants provide the optimal cost-effective generation of electricity. The electrical energy generated by these power plants is transported to the end users using a hierarchical structure of high-voltage (HV) transmission networks and medium-voltage (MV) and low-voltage (LV) distribution networks, as shown in Fig 2.1.

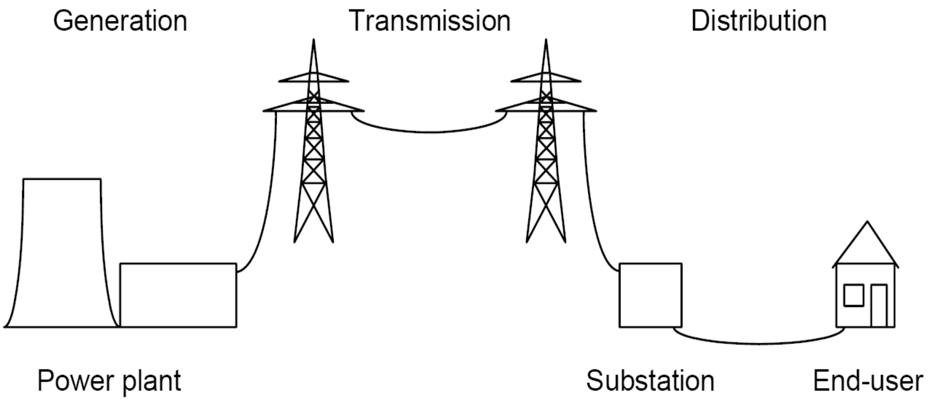

Fig 2.1: Schematic representation of an electrical power system

To ensure both a high security and availability, most of the networks have been meshed, to provide alternative routing in case of faults. They are protected from critical failures and natural phenomena, such as lightning strikes, with mechanical and electronic protection schemes. The networks are characterized by a power flow from a relatively small number of large power plants to a large number of dispersed end-users [7].
The transition towards a more sustainable energy supply changes the demand and supply of energy and this has consequences for the MV-networks which supports the transport of electricity generated and consumed.

2.1.1 MV network structures in the Netherlands

The network structure is formed by overhead lines, underground cables, the transformers and buses between the points of power injection and power consumption. The number of voltage transformations from the highest voltage level to the lowest voltage level determines the principal network structure of a system [8].

Dutch MV (and LV) networks entirely consists of underground cables. Only on a few locations overhead lines are used because of too wet soil conditions. MV networks are mainly operated on 10kV, but also other voltage levels (3, 6, 12, 20, 25, 30kV) exist [9]. LV networks are operated on 230/400 V.

2.1.2 MV transmission network

MV networks may have a transmission function in addition to the distribution function. A medium voltage transmission (MV-T) network consists of a bundle of MV-T cables with one or more MV-T substations and/or MV-T connections in a meshed structure. The n-1 principle is applied to the MV-T cables. The n-1 principle is a situation where the unavailability of <u>one</u> component (maintenance or failure) does not lead to an interruption of the electricity supply. Voltage or load levels should stay between acceptable limits during this situation.

A MV-T substation can be fed from a high voltage/medium voltage (HV/MV) station or from another MV-T substation. This can reduce the costs of the cable length and/or an expensive outgoing HV/MV installation [10]. Figure 2.2 shows some example configurations.

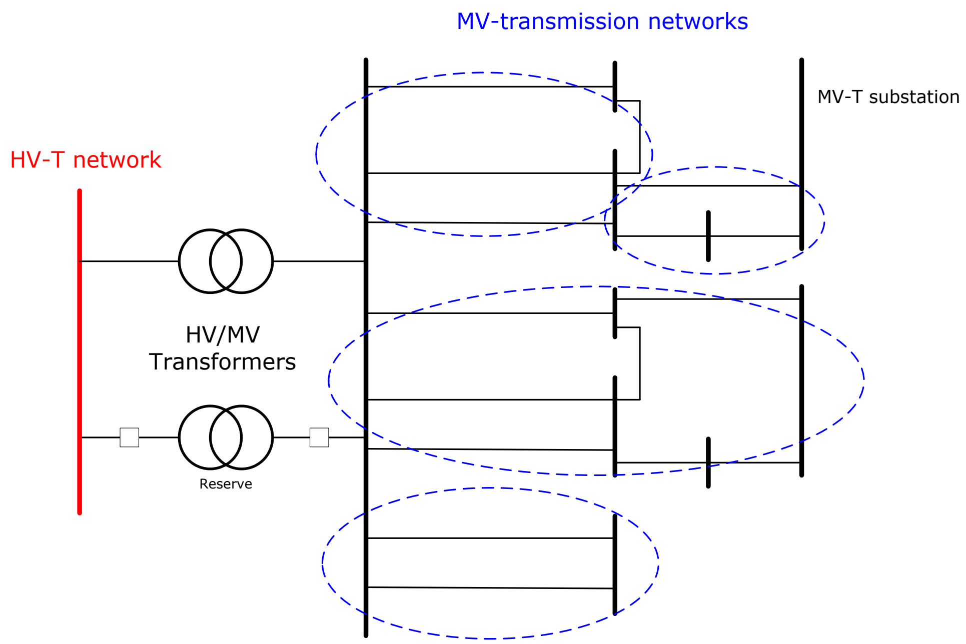

Fig 2.2: Example configuration of MV-T networks

A MV-T network is limited to substations which have to be supplied by the same HV/MV transformer in order to avoid large settlement currents.

2.1.3 MV distribution network

A medium voltage distribution (MV-D) network distributes electrical energy from a central point (MV-T substation or HV/MV station) to various MV-D stations (network station or customer stations, see §2.3). At Enexis, MV-D networks are placed in a meshed structure, but are radial (star structure) operated. This is possible with the use of normally open points (NOP). These NOPs can split up distribution-rings and can be rescheduled during a fault. With this principle a redundant (n-1 secure) network is created. In some cases pure radial networks are applied. A radial network cannot be rearranged and is therefore not redundant. Some example configurations are shown in figure 2.3.

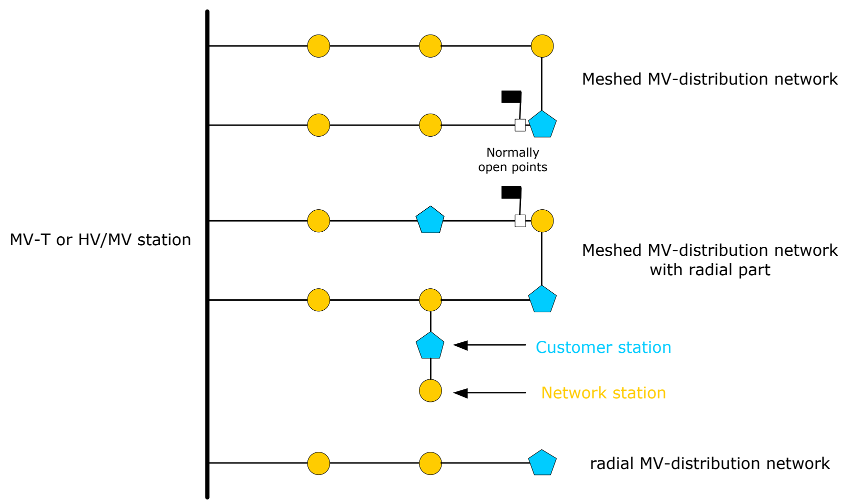

Fig 2.3: Example configuration of MV-D networks

2.2 Medium voltage components

A MV network exists of several components to transport various amounts of electrical energy over various distances. Examples of these components are cables, transformers, installations, switches, etc. All of these components have their own specific function and are in their own way indispensable to transport electrical energy on a save and reliable manner. The scope of the research focuses on HV/MV transformers, MV cables and MV/LV transformers.

2.2.1 *Transformers*

Transformers are essential components in the power system as they make it possible to convert electrical energy to different voltage levels with an efficiency of more than 99 %. That enables us to generate power at a relative low-voltage level (10-25kV, limited by the insulation of the generator), to transport it at high voltage levels (110kV-420kV and higher) to reduce the losses during transportation, whereas domestic consumption can take place at a low and (more or less) safe voltage level (230/400V) [8].

For MV networks there has to be made a difference between HV/MV transformers, MV/MV transformers and MV/LV distribution transformers. HV/MV transformers in the Netherlands are usually made to transform a high transport voltage of 380, 220, 150 or 110kV to a lower transport voltage like 10kV. The high voltage that is used to transport very large amounts of energy is not necessary for the transport of smaller amounts. It would cost too much to use a HV network for such a situation, and is less practical in urban areas.

Transformers which are used to transform a medium voltage to another medium voltage are MV/MV transformer. These are often used to transform a transport voltage to an area dependent voltage. For example, a new MV-T network operational on 20kV has to be transformed to 10kV, because the area where distribution takes place has an existing 10kV network. MV/MV transformers also exist to regulate the voltage. Sometimes the voltage reaches its upper or lower limit. Therefore the voltage can be regulated down or up by a 10kV/10kV transformer, which should preferably be located somewhere halfway the MV-T network.

Fig 2.4: Example of a HV/MV transformer designed by SMIT

The HV and MV networks provide supplies direct to large customers, but the vast majority of customers are connected at the LV-level and supplied via MV/LV distribution substations and their associated LV networks. In this distribution substation a MV/LV transformer is present, also called a distribution transformer.

2.2.2 *Power carrier: underground cables*

It is in principle an economical and an environmental issue whether to choose an overhead line or an underground cable for transmitting and distributing electrical power to densely populated areas. Underground systems are in general more reliable than overhead systems, because they are not exposed to wind, lightning, vehicle damage, and they require less preventive maintenance. The main disadvantage, however, is the higher costs (6-10 times more expensive than overhead systems for the same power rating). In the densely populated Netherlands almost all conductors below the 50kV level are underground cables, as shown in table 2.1 [8].

Table 2.1: The power carriers in the Dutch power system, 2007 [11]

Voltage range [kV]	Aboveground [km]	Underground [km]
220 / 380	2719	16
50 / 110 / 150	5580	3614
3 - 25	-	105599
3 - 25	174	150623

The conductor material can be either copper of aluminum. The resistivity of copper is 60% that of aluminum[1]. The types for MV cables are standardized to decrease investment costs. Currently Enexis uses the following standards for new MV cables, which resulted from their last European procurement round.

Fig 2.5

10 kV Cables for MV-T and MV-D networks:
1 x 150 AL 6/10 XLPE
1 x 240 AL 6/10 XLPE
1 x 400 AL 6/10 XLPE
1 x 630 AL 6/10 XLPE

All cables are of the type: aluminum cross-linked polyethylene (XLPE). These are polyethylene insulated cables with an aluminum single core. The thicknesses that have been standardized are 150mm^2, 240mm^2, 400mm^2 and 630mm^2. Plastic is a solid insulator which, during the manufacturing of the cable, is melted and pressed around the conductor. The insulation must be free of cavities and inclusions (dust, fibers, metal particles) in order to prevent failures during operation. Polymer insulation is highly vulnerable for water (vapor), as it lowers the dielectric withstand level. Therefore the insulation is sealed against water by a lead sheath [8]. Figure 2.5 shows an aluminum single solid core XLPE cable.

Although new MV cables are XLPE aluminum cables, still many cables in the present network are of other types, like paper-oil insulated cables and/or in combination with copper (three-core) conductors. An old standard was the so-called PILC cable[2] (Paper Insulated Lead Covered).

2.3 MV connection types

The way of connecting customers to the MV network is completely standardized. This standardization has a narrow link with the various tariffs for connection. These connection tariffs are approved by the DTe (Dienst Toezicht Energie / Office of Energy Regulation) and elaborated in a tariff overview. The category of the connection is determined by the requested connection capacity of the customer. The DSO is always looking for the optimal connection. In principal there are two different connection types/stations in the MV network, the so-called customer stations and network stations:

- *Network station*: this is a transformer station fed from the MV-D network and supplies electrical power to the (public) LV network. This is made possible by a distribution transformer (MV/LV transformer). This MV/LV transformer is mainly loaded by the following connections on LV:
    - Small consumers (connection until 3x80A)
    - Large consumers (connections from then 3x80A to 250A)
    - Public Lighting (PL)

[1] Although aluminum cables have higher losses then copper cables, almost all DSO's currently invest in aluminum MV cables due to a much lower price of raw material.
[2] In Dutch: GPLK (Gepantserde Papier Lood Kabel)

- *Customer station*: an MV station that completely fits the needs of a customer (also called a business customer): the structure depends on the category of the connection. The MV connections are separated in four different categories which are distinguished by connection capacity:
  - MV-D connection 173kVA (250A) - 1.750kVA
  - MV-T connection 1.750kVA - 6.000kVA
  - HV/MV connection 6.000kVA - 10.000kVA
  - HV/MV connection > 10.000kVA

Every connection has a transfer point/border. The main grid until this transfer point is regulated. The DSO is (financial) responsible and mandate for the execution of this regulated part. The area after this transfer point (seen from the network side) is the non-regulated part. The customer is (financial) responsible and free in the execution of this part, as long as it is in rule with the category of connection [12].

An example of a standard MV connection of a customer station follows.

MV-D connection > 173 kVA - 1750 kVA

This standard connection is separated into two groups. Only group A (173 kVA - 650 kVA) is presented here. This connection is provided with two load switches at the cable side (incoming side) and one load switch secured with fuses at the outgoing side. The measurement installation is situated at the LV side.

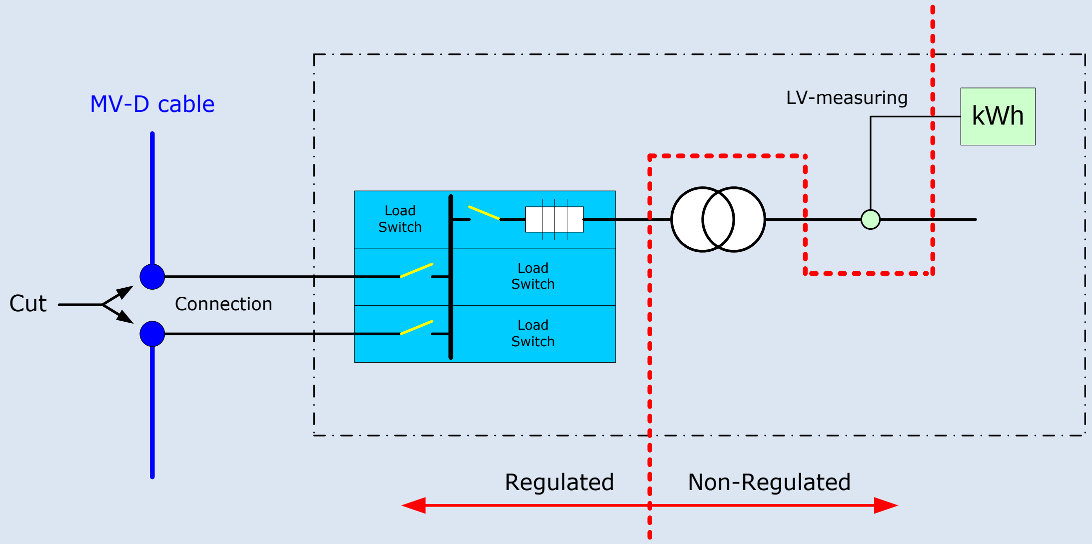

Fig 2.6: Standard MV-D connection > 173 kVA t/m 650 kVA

The standard way of connection is through a connection into the (nearest) appropriate MV-D cable. This MV-D cable is connected to a MV-D, MV-T or HV/MV station. The transformer belongs to the non-regulated part, the customer is able to rent one from the DSO or a third party.

2.4 Relevant guidelines

Enexis established guidelines for the design of MV networks. A good network design consists of a certain number of steps, in which reliability, quality, safety and performance must be equally balanced. Guidelines and design criterions are important for making good and founded choices. Besides that, they contain minimum requirements for capacity, safety and performance. In the following paragraphs some of the most common and important guidelines for this project are described [10,12].

2.4.1 Cable loading

The loading of a cable is the percentage of the available capacity which is being used by the maximum load. The cable load can be calculated by dividing the maximum load at a certain point in time, by the capacity at that time. In this paragraph it is shown how to calculate the capacity of the cable [12,13]. To determine the capacity of the cable, Enexis takes the following factors in consideration:

- Applied cable type (Paper insulated lead covered (PILC) and cross-linked polyethylene (XLPE), Aluminum and Cupper) and cross section
- Thermal influence of parallel cables close to each other
- Heat development of unequal loaded cables.
- Ground temperature at the depth of the cable
- Thermal resistance of the ground
- Pattern/profile of the load

The influence of these factors at the capacity of the cable has been processed in the following formulas:

$$I_{max\_equal\_loaded} = I_{nom} \cdot P \cdot T \cdot D \quad (2.1)$$

$$V = \sqrt{\frac{\sum I^2_{max\_equal\_loaded}}{\sum I^2_{load}}} \quad (2.2)$$

$$I_{max\_unequal\_loaded} = I_{load} \cdot V \quad (2.3)$$

$I_{max\_equal\_loaded}$	=	maximum load of MV cables with an equal load division at parallel cables
$I_{max\_unequal\_loaded}$	=	maximum load of MV cables with an un-equal load division at parallel cables
I_{load}	=	measured or calculated maximum load of a MV cable
I_{nom}	=	Cable loads in conformity with table A.1
P	=	Correction for the thermal resistance of the ground and thermal influence of parallel cables
T	=	Correction for the ground temperature
D	=	Correction for the load pattern
V	=	Correction for parallel cables with a different cable load

The formulas results in a season dependent capacity, because some of the factors in the formula can have different values at different months in the year. There's a difference between the winter months (dec, jan, feb, mar) and the summer months (jul, aug, sept). A certain limit value is calculated for the cable load. The cable load in the remaining months is linear between these two limits. The correction factors of the capacity formula are commented in appendix A.

With these guidelines and formulas it is possible to calculate cable loads as approximately real values. These values are necessary for a good simulation of an MV-network.

2.4.2 Transformer loading

This paragraph describes a loading guide line for distribution transformers (with a maximum rating of 2500kVA) and medium power transformers (with a maximum rating of 100MVA). The normal life expectancy is given based on the preconditions of continuous duty under a certain ambient temperature and rated operating conditions. If the load exceeds the predefined 'nameplate' rating, which is given for the defined preconditions, -and/or the ambient temperature is higher than the predefined value of the ambient temperature, then there is a risk of accelerated ageing [14].

The consequences of loading a transformer above its nameplate rating are as follows:

- The temperatures of windings, cleats, leads, insulation and oil will increase and can reach unacceptable levels.
- The leakage flux density outside the core increases, causing additional eddy-current heating in metallic parts linked by the leakage flux.
- As the temperature changes, the moisture and gas content in the insulation and in the oil will change.

- Bushings, tap-changers, cable-end connections and current transformers will also be exposed to higher stresses which encroach upon their design and application margins.

As a consequence, there will be a risk of premature failure associated with the increased currents and temperatures. This risk may be of an immediate short-term character or come from the cumulative effect of thermal ageing of the insulation in the transformer over many years. Three loading conditions of MV/LV transformers can be distinguished [12]:

- *Normal loading*: The load is not higher than the nominal (electrical) capacity of the transformer. The capacity of MV/LV transformers in network designs of Enexis are specified by an expected load growth in addition to a base load for a period of 30 years. This 'end-load' will be in the range of the normal loading area.
- *Overloading*: If the thermal loading is higher than the nominal thermal capability. In this loading area is the ageing rate higher than 1, which means a reduced life expectancy.
- *Maximum load*: A MV/LV transformer is maximal loaded by the limits described in the IEC norm [12]. Exceeding these limits will result in excessive reduction in life expectancy.

The loading limits of transformers are technically of thermal nature. However, within Enexis, the electrical loadings of transformers are registered. The relation between the thermal load and electrical load is far from simple, but very essential. Therefore, the electrical load is used as a first indication. Additionally, a temperature measurement is performed if the threshold (of the electrical load) is exceeded. When both the electrical loading threshold is exceeded and the temperature measurement indicates a thermal exceeding, the transformer is indicated to be unacceptable overloaded.

Table 2.2 shows the maximum allowable electrical load of MV/LV transformers based on load patterns/profiles. For an explanation of the "Load cyclic" see appendix B.

Table 2.2: (Over)load factors for 'oil' and 'dry' transformers with normal life expectancy

Load Profile	Load cyclic		Max. allowed electrical load to S_{nom}	
	K_2/K_1	*t (hour)*	*Oil* $(\theta_A = 30°C)$[3]	*Dry* $(\theta_A = 30°C)$
Residential	1,6	4	1,16	1,10
Mixed	2,3	8	1,08	1,04
Industrial	2,7	8	1,08	1,04
Generation (e.g. DG)	1	24	0,9	0,95
Individual customer	1	24	0,9	0,95

Dry distribution transformers are not used for network transformers, but only at customer stations if the customer requests one. Because the simplified load profiles (described in the appendix) result in some small errors, an additional temperature measurement (after exceeding the electrical loading threshold) will take place. For the analysis in this report, the assumption has been made that exceeding the electrical loading threshold means overloading of the transformer. This is a conservative assumption.

2.4.3 Voltage deviations

Components and devices connected to the network are designed to operate within specific limits for voltages (and currents). Operating outside these limits may result in a break down, malfunctioning or extra ageing. When the voltage gets too high devices can be damaged. When the voltage is too low devices do not work properly or may even break [9].

With the control of voltage deviations inside a MV network is it necessary to check if the absolute value of the voltage is correct, and that slow voltage fluctuations stays within a certain range. Slow voltage fluctuations are variations in the time domain > 1 minute and a voltage level

[3] Ambient temperature of $\theta_A = 30°C$ is taken into account. This value is the summation of the average temperature in the hottest month $(20°C)$ and a temperature rise of $10°C$ due to line-up of the transformer inside a containment.

between the 90% and 110% of the operational voltage. These voltage limits count for the normal, stationary situation. These limits can only be exceeded in case of failures and maintenance circumstances. The voltage level in a MV network varies due to the transport of active and reactive power and is mainly dependent on the:

- Network configuration
- Length of cables
- Capacitor banks and coils
- Characteristics of the load
- The (changing) demand for reactive power
- Voltage control of the HV/MV adjustable transformer

The following voltage limits are fixed by Enexis, based on the Grid Code[4]:

- The upper and lower limit of the absolute MV (10kV) are **11,25kV** and **9,5 kV**. For 20kV counts the limits **22,5 kV** and **19 kV**. These limits are not allowed to be exceeded under any circumstances.
- For the 3kV networks no fixed limits are established, because no MV connections are realized to this network. It serves only as a feeder to the LV networks.
- The permitted LV bandwidth (phase voltage) is: **207 V** until **252 V** (230V ± 10%) at the transfer point.

Due to the continuous voltage control of the HV/MV transformer, the large variations in the HV network are not much noticed in the MV network. Towards the end of the MV network, the voltage variation increases due to the variation of the power flow in the MV network. In general the MV/LV transformer does not have any voltage control (the setting of the taps is fixed). Therefore, the voltage variation noticed on the LV side of this transformer will almost be the same as on the MV side. In reality, this variation will be slightly more due to the voltage drop across the MV/LV transformer [9].

4 The Electricity Act (1998) stipulates that the joint grid administrators must submit proposals to the Office of Energy Regulation (DTe) detailing a tariff structure and a set of technical conditions (regulations) for grid administration. The Grid Code is one of these technical regulations. DTe has evaluated and adopted the Grid Code proposal submitted by the grid administrators

3 Network calculations and network files

Network calculations cannot be missed for the analysis of (future) network design, planning and performance. Nowadays these calculations are performed by advanced computer programs. In the Netherlands commonly used programs are *Vision Network Analysis* for MV and HV power systems and *GAIA LV Network Design* for LV power systems. This chapter describes the used software, calculation method and the set of MV network that has been analysed with future load conditions.

3.1 Vision Network Analysis

Vision Network Analysis is an advanced tool for electric network analysis. The software can be used for load flow and short circuit calculations and for fault and reliability analyses. It can also be used to simulate the function of protections. Vision is used for the planning, design and management of transmission, distribution and industrial networks. Vision Network Analysis uses a very fast graphical editor with an extremely short familiarization time, thanks to carefully chosen edit functions. The program can handle very large networks, making it suitable for linking networks with geographical information systems. The user interface is designed to look and feel like common Windows products. This makes Vision Network Analysis accessible both to frequent and occasional users. The presentation of the network and associated information, such as component data and calculation results, can be fully configured by the user [15].

3.2 Load-flow calculation

There are many types of calculation for power systems. The load-flow is the most important network computation/calculation, as it allows insight into the steady-state behaviour of the power system. Information is received about voltages, currents and power flows in the network. Load-flow calculations are therefore necessary for network planning, network extension and network operation. The load-flow computation needs of course input data and, after performing the necessary calculations, generates output as shown in figure 3.1. The input data consists of the network topology, network parameters and node information.

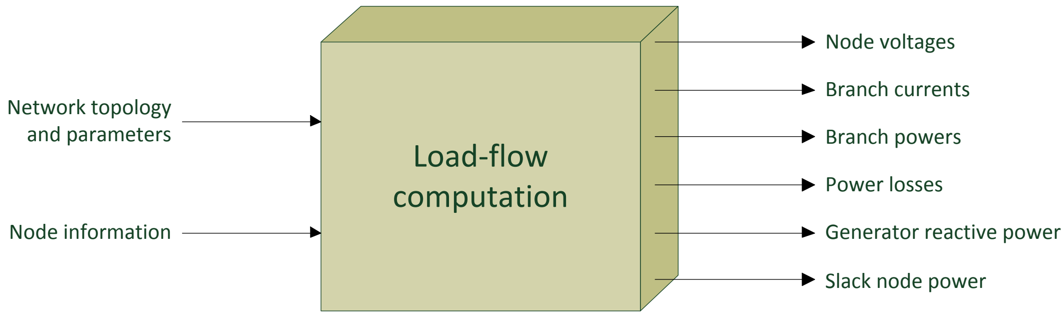

Fig 3.1: Load-flow computation: input data and computational results [8]

A network node is fully described (electrically) by four parameters:

- The voltage magnitude: $|V|$
- the voltage angle: δ
- The injected active power: P
- The injected reactive power: Q

For each node in the network only two of the four parameters are known (dependent on the type of node). The load-flow calculation computes the two unknown parameters and solved iteratively using a special technique/method. Vision Network Analysis uses the so-called *Newton-Rapshson* method for calculating the load-flow. It is an iterative technique for solving a set of nonlinear equations. The iterations start with an initial estimate for the unknown parameters and the process is repeated until the mismatches (in power) are lower than a specified tolerance. The Newton-Rapshson method has a very good convergence rate and is widely accepted for network calculations. The computation time increases only linearly with the system size and is particularly suited for applications involving large systems requiring accurate solutions [18].

More information on this topic can be found in [8, 16, 17, 18].

With the use of the load-flow calculation it's possible to determine the three main parameters regarding network planning that were stated in the objectives:

- Node voltages
- Energy losses
- Component loadings

3.3 Vision Network Files of existing MV networks operated by Enexis

All kind of information about MV networks is saved in different large databases of Enexis. These databases contain information about e.g. installed assets (properties, name plate data, age, location, etc.) and recent measurement data of load conditions. This information is however not always easily accessible. Some attempts in the past have been taken to connect all these databases and generate Vision Network Files (VNF) of all existing MV networks of Enexis. This is however not yet realised for all 'network regions[5]' of Enexis.

Only VNFs of the northern network regions are at this moment useful for the desired analysis, because the data of these files is complete and they are identically build up. This set of VNFs of the existing MV networks are updated by means of network structure and measurement data until the end of 2007. The VNFs covers the red shaded part in figure 3.2.

The VNFs cover the existing network beginning at the HV/MV transformer until the MV/LV transformer at the customer and network stations. Figure 3.3 shows a schematic drawing of the network structure.

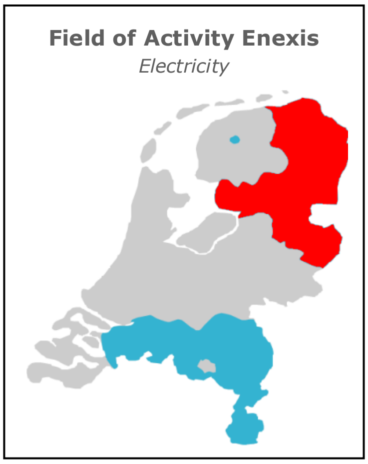

Fig 3.2: MV networks under analysis

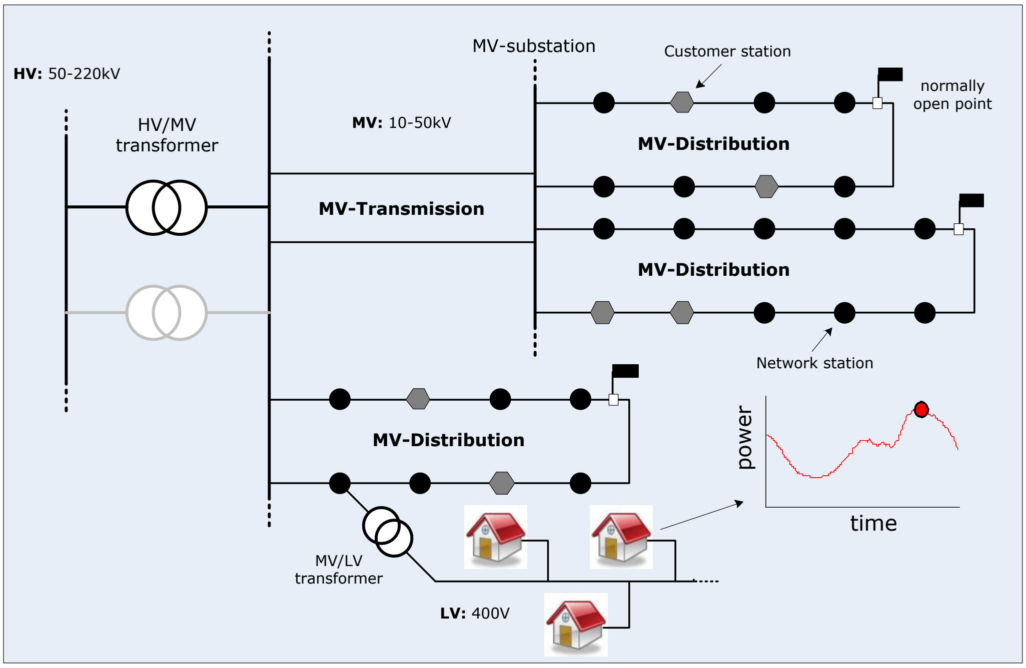

Fig 3.3: Structure of the existing MV network

5 The Asset Management department of Enexis is split up in 5 regions, namely region Groningen, region Zwolle, region Limburg, region East-Brabant and region West-Brabant.

Seen from the MV network there are two types of stations with a certain load (or generation in case of DG); customer stations and network stations. Customer stations have a certain maximum connection capacity (see §2.3) and a contracted (peak) power which is registered and verified by the DSO. The MV-network is dimensioned on the contracted power (smaller or equal then connection capacity) and these peak powers are incorporated in the VNFs.

Load measurements at network stations take place ones a year. Distribution transformer loadings are measured by means of (thermal) Ampère meters or a combined kW_{max} and kWh measurement, which is currently the standard within Enexis. This produces only a single measurement value: P_{max}. This means load profiles are normally not measured. However, it is known, that the load profile at the MV/LV transformer level of a certain customer group looks roughly like the load profile in figure 3.3.

The P_{max} for one year is known, but the accompanying power factor ($\cos\varphi$) is not always measured. If the power factor at customer stations and network stations is unknown, a power factor[6] of 0.85 is mostly taken into account. The electrical load in this case will be:

$$S_{max} = \frac{P_{max}}{0.85}\ [kVA] \qquad (3.1)$$

In order to get "worst-case results" calculations are performed using the maximum electrical load at all stations, giving the largest voltage deviations and component loadings.

3.4 Dataset

In the analysis a large number of MV networks (about 50) in the Netherlands are considered (located in red area of figure 3.2). Table 3.1 shows an overview of the approximate number of records. Appendix C shows more specific data with distributions of different asset types. Many different types of cables and transformers operated on three MV levels (3kV, 10kV and 20kV) are present in these existing MV networks. Therefore the types are categorized, resulting in the graphs of Appendix C. The raw data with all the different component types in the field is presented in Appendix C5. Only networks and assets operated by the DSO are considered in Appendix C, e.g. transformers at customer stations are not presented.

Table 3.1: Description of dataset

Dataset:	Approximate number of records:
MV networks	50 pcs
MV/LV transformers	13.000 pcs
MV-Distribution cables	14.000 km
MV-Transmission cables	3.300 km
HV/MV transformers	130 pcs
HV/MV stations	55 pcs

3.5 Coincidence factor

In MV networks some coincidence factors play an important role in calculating maximum loading situations [9]. The MV-D cables are radially operated under normal circumstances because of the NOP. MV/LV transformers (customer and network stations) with a certain maximum load are connected to these radially operated MV-D cables. A coincidence factor for these cables should be taken into account before starting any load-flow calculation. This is done because the maximum outgoing power at the beginning of the MV-D cables (which is measured at the MV substation) is <u>not equal</u> to the sum of the individual peak loads of the connected stations. This can have several reasons:

6 A power factor of 0.85 is the minimal allowed value where no transport tariffs for reactive power applies, based on the connection conditions and the Tariff Code.

1.) The maximum loads did not occur at the same moment. This can be shifted in time on the same day, but also at difference in days. One peak is for example measured at January 3rd and the other at December 6th.
2.) Industrial and residential loads have different load profiles with different peak moments.
3.) A MV/LV transformer without measurement data will have a loading of 0 (virtually in the VNFs), although in reality it is loaded. Now it is even possible to get coincidence factors higher than 1!
4.) Loads that are not present in the VNFs, but do exist in reality. Non-technical energy losses (see §8.1) can also be part of this. A coincidence factor higher than 1 is in this case also possible.

These aspects are compensated by adding coincidence factors, so the maximal measured power at the beginning of the MV-D cable equals the calculated values in the VNFs. The coincidence factors are connected to each node of the MV-D cable with a load (MV/LV transformer). This factor is the same for all nodes connected at one cable. This is visualized in figure 3.4, which is part of a larger figure which can be found in Appendix D.

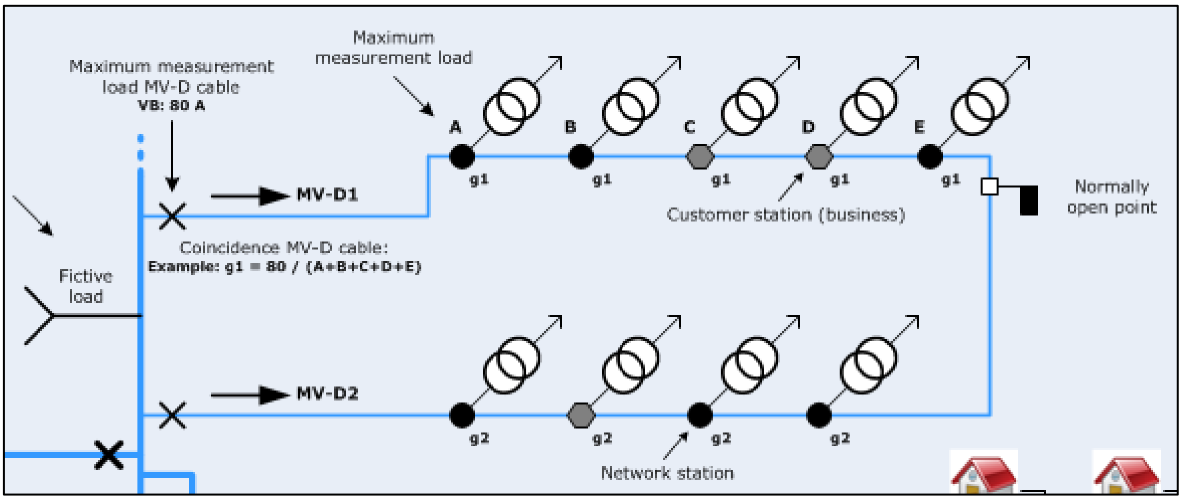

Fig 3.4: Coincidence factors in MV-D cables

The coincidence factor can be calculated by simply dividing the sum of the measured individual peak loads at the stations over the maximum load at the beginning of the MV-D cable:

$$coincidence\ factor\ \boldsymbol{g} = \frac{max.load\ of\ MV\ Cable}{\sum connected\ peak\ loads} \quad (3.2)$$

The different radially operated MV-D cables come together at the MV substation, and are from here connected at the HV/MV station by a MV-T network/track (see Appendix D). Here a coincidence factor is also added. The summation of the maximum measured outgoing powers of the individual MV-D cables is again <u>not equal</u> to the loading of the MV-T network. In order to calculate the correct values for the maximum current/power, special measures must be taken in the software. An example is adding fictive (negative) loads at the MV-T substation (see figure 3.4 and Appendix D). These loads must compensate the differences. This has the advantage that standard load-flow solution methods can be applied. Otherwise a stochastic load-flow is needed, where the loads consist of a deterministic part (e.g. daily load profile as function of time) and a stochastic part (e.g. the random variation of the load) [9,19]. However, for stochastic calculations a large amount of data is needed (which are not always available) and more calculations need to be executed, which make the calculations more complex and time consuming.

4 Future Scenarios and Load Profiles

There is much uncertainty about the future energy supply. Sustainable energy sources and energy efficiency become more important, but to what extent? Which technologies will be most successful and how fast will these develop? E.g. a fast or slow introduction of electric vehicles has a large impact on the need for transport of electric energy. Also, the amount of energy produced and consumed is for a substantial part defined by the economic growth. When investigating the impact of future loads and generators on the electricity networks, different directions in which future energy needs may develop need to be regarded. Therefore, three future scenarios are defined by [4].

After exploring various important scenario studies the drivers that lead to variations in the future energy supply and demand, can be identified: depending on a more national or international focused policy, a more economic or environmental oriented society and the economic growth, the future energy supply can develop in different directions [4]. Differentiations in these drivers will lead to very different, but all realistic, future scenarios. Therefore, three scenarios based on divergent choices concerning these underlying drivers are defined; these scenarios comprise the possible variations in the future energy supply. Because network planning is done with a time horizon of 25 to 30 years, the scenarios are defined for the year 2040.

The need for transport of electricity on the distribution level of the energy systems depends on the amount of energy produced and consumed and on the location of the load and generators. The transport of large amounts of electricity from a central location (e.g. large power plants) to customers in a densely populated area asks for a different energy system than a system with many local distributed generators close to the end-users. Also, due to the applied policies some (new) technologies may be more and others less successful. Therefore, the established scenarios have different consequences for the energy supply, in terms of the expected demand growth of electricity, the voltage level to which generators are connected and developments of new technologies.

In Table 4.1 the three scenarios are summarized and it is indicated what these mean for the electricity supply and demand on the distribution level of the grid, and which technologies are applied on the residential level.

Table 4.1: Overview of the three future scenarios

Scenario A	**Scenario B**	**Scenario C**
The market and policies do not change much compared to 2011. The economic growth is limited, there is an effective national policy and the focus is on economics. This leads to a more centralized energy supply and a focus on energy savings. Compared to the other scenarios, not many new technologies are introduced.	A global economy dominates. The economic growth is high, which leads to a high demand for energy. To be able to cope with the increase in energy needs of the population, the focus is on energy savings. Electrification of heating and mobility grows fast.	The applied energy policies have a local and environmental focus. Many investments are made in new technologies, leading to an increasing application of new technologies and growth of supply on decentralized level. Economic growth is high, but the effect on the energy demand is average, because of the focus on energy savings and efficient technologies.
	Effect on the supply of electricity	
Mostly centralized production (on the HV-level), less supply on the MV- and LV-level than in 2011; not many solar panels and micro-CHPs.	Growth of generation on all levels (relatively more on the HV-level); solar panels and micro-CHPs on a limited scale.	A large increase of distributed generation on the LV- and MV-level; many solar panels and micro-CHPs
	Effect on the demand of electricity	
Demand growth 0.5%, few electric vehicles, heat pumps mainly in newly developed areas.	Demand growth 2%; many heat pumps and electric vehicles.	Demand growth 1%; many heat pumps and electric cars

The next paragraphs present shortly some more detailed specifications for the three scenarios. Concerning the residential areas, a total of 10 different types are defined, depended on location, population density and age. There are some differences in new technologies between the types of residential area. In the following overviews, only a distinction has been made between existing neighborhoods and newly-built residential areas, because these differences are the largest. For example, in [4] it is assumed[7] that there will be no micro-CHP present in newly-built areas, but instead heat pumps with additional resistive heating will be used. The two residential areas are each divided into 5 classes (urban…rural), which make in total 10 different types of areas.

4.1 Scenario A

- Most production central at HV
- Small rise of 'normal' electricity demand (0,5% per year)
- Few distributed generation at low voltage (photovoltaic panels & micro-CHP)
- Limited introduction of electrical vehicles & heat pumps

Table 4.2: Specification of scenario A

Technology:	Existing residential areas:	New residential areas:
Photovoltaic panels		
Penetration degree	0,1 -0,3 m2 / household	0,2 -0,7 m2 / household
Efficiency	20%	22%
Electrical vehicles		
Penetration degree	39%	39%
Average distance	23–51 km/day	23–51 km/day
Micro CHPs		
Penetration degree	5-10%	-
Electrical power	1 kW	-
Thermal power	6 kW	-
Heat Pumps		
Penetration degree	5%	42%
Compressor power	0,7 -1,1 kW	0,9 -1,4 kW
Heating element	-	4,2 -6,5 kW

4.2 Scenario B

- Growth of large scale (central) production at HV
- Large rise of 'normal' electricity demand (2,0% per year)
- Few distributed generation at low voltage (photovoltaic panels & micro-CHP)
- Many electrical vehicles & heat pumps

Table 4.3: Specification of scenario B

Technology:	Existing residential areas:	New residential areas:
Photovoltaic panels		
Penetration degree	0,1 m2	0,2 -0,5 m2
Efficiency	20%	22%
Electrical vehicles		
Penetration degree	75%	75%
Average distance	24–52 km/day	24–52 km/day
Micro CHPs		
Penetration degree	3-6%	-
Electrical power	1 kW	-
Thermal power	6 kW	-
Heat Pumps		
Penetration degree	70%	70%
Compressor power	0,6 -0,9 kW	0,7 -1,1 kW
Heating element	-	3,6 -5,4 kW

[7] Micro-CHPs run on gas. In the Netherlands many residential houses have a connection to the gas network. However, newly developed areas are often built without gas networks and (only) heat pumps are used for heating houses. On the other hand, in an existing neighbourhood, gas networks may still exist and micro-CHPs may be applied.

4.3 Scenario C

- Less central production at HV
- Medium rise of 'normal' electricity demand (1,0% per year)
- Many distributed generation at LV and MV: (photovoltaic panels & micro-CHP)
- Many electrical vehicles & heat pumps in new residential areas

Table 4.4: Specification of scenario C

Technology:	Existing residential areas:	New residential areas:
Photovoltaic panels		
Penetration degree	3-8 m2	4-11 m2
Efficiency	20%	22%
Electrical vehicles		
Penetration degree	75%	75%
Average distance	24–52 km/day	24–52 km/day
Micro CHPs		
Penetration degree	32-42%	-
Electrical power	1 kW	-
Thermal power	6 kW	-
Heat Pumps		
Penetration degree	35%	68%
Compressor power	0,6 -1,0 kW	0,7 -1,2 kW
Heating element	-	3,6 -5,5 kW

4.4 Aggregated residential load profiles

For the three scenario in 2040, aggregated load profiles of future residential areas are constructed, by the techniques proposed in [3,20]. Besides these profiles, the aggregated profiles are constructed after a control strategy is applied for flexible, not time-critical loads.

An example for both the uncontrolled and controlled (smart) case is presented. Figure 4.1 presents aggregated (uncontrolled) load profiles for the year 2040 for an existing neighbourhood; the aggregated profile is scaled back to the average profile for only one household. For network planning, the worst case situation is of most interest. Therefore, the profiles are shown for a cloudy, cold winter day when heat demand is large and there is no generation by PV panels. This is the maximal expected load in the year. The figure also shows the individual load elements. Micro-CHPs and heat pumps are on maximum power all day long (which results in continuous power demand). In this case the charging of EV is not controlled, and a fixed charge rate is assumed.

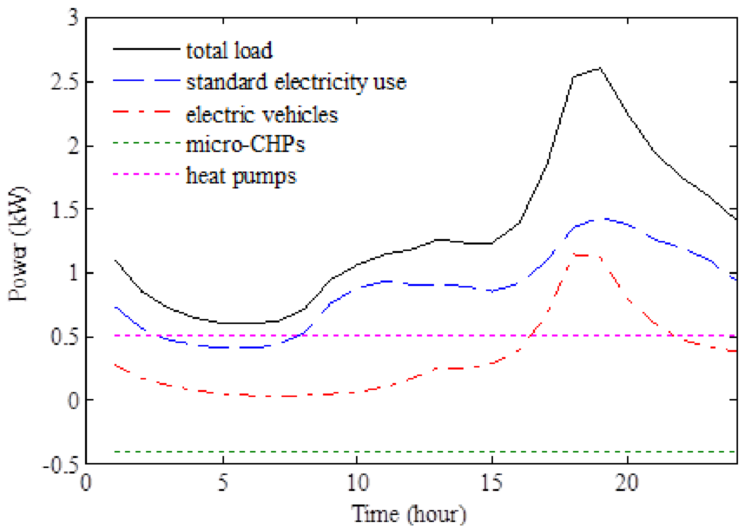

Fig. 4.1. The total aggregated load and individual load and generation elements of an existing neighbourhood in winter (scaled back to one household)

Control of a part of the load and generation will result in different aggregated loads, presented in Figure 4.2. When comparing the profiles of the individual elements with the profiles in Figure 4.1, it can be seen that a large part of the electric vehicles is now charged during the night instead of during the evening peak. Furthermore, it can be noted that no change is found in the profile for the heat pumps in spite of the applied control strategy. This is caused by the fact that the heat pumps are operating on their maximum power all day long which leaves no space for shifting demand. The profiles of the standard electricity use did not change that much, because only 10% of this demand is controlled. The largest contribution to the reduction of the peak load is thus caused by smart charging of electric vehicles.

This control strategy, defined in [20], results in lower peak loads which would require less network capacity. The resulting peak loads and profiles are used for the load flow calculations.

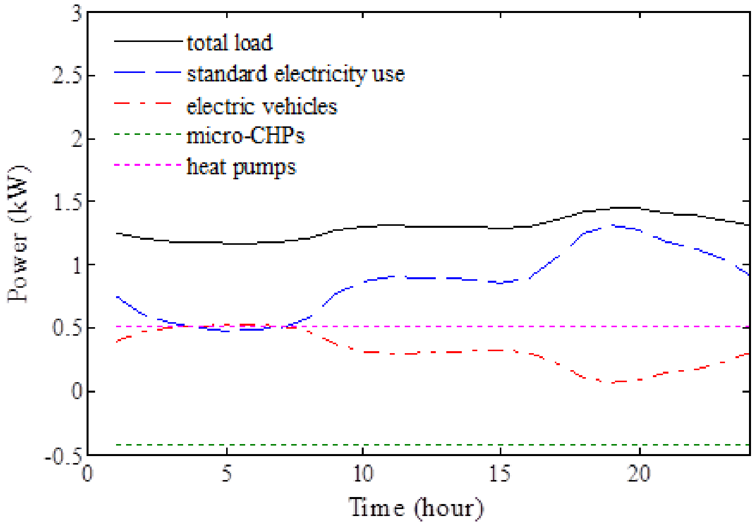

Fig. 4.2. The total aggregated load and individual load and generation elements of an existing neighbourhood with smart control of electric vehicles, heat pumps and demand-side management (scaled back to one household)

5 Adjusting the Existing MV Network to Future Scenarios

The existing residential loads in the set of 50 MV networks are altered to future conditions. The established scenarios provide needed information for this step (e.g. penetration degrees of future techniques depended on location and population density). These future parameters are translated to aggregated load profiles and will function as input data for the network simulations. In cooperation with Phase to Phase, the developers of Vision Network Analysis, a special tool is developed (*Visienexis*) for adjusting the MV networks to future scenarios and performing multiple load-flow calculations at the same time. This chapter describes briefly these two functions of Visienexis.

Visienexis adjusts the existing loads in the MV networks to future load conditions (see figure 5.1). First, a desired set of simulation files (VNF) is selected. All kinds of input parameters which are needed for adjusting the loads in the network is delivered by an Excel file. This 'Excel-input-file' contains information about the new load profiles, normal growth factors and rise in demand due to new technologies (EVs, heat pumps, PV, micro-CHP). These input parameters are divided into two groups to distinguish non-residential loads (customer stations) and residential loads (network stations). The residential loads are split up in subgroups to represent different residential areas, dependent on location (population densities). 6-digit postal codes are coupled to a subgroup (residential area). This is included in the Excel-input-file. A flow-chart of the load adapting method is presented in figure 5.2.

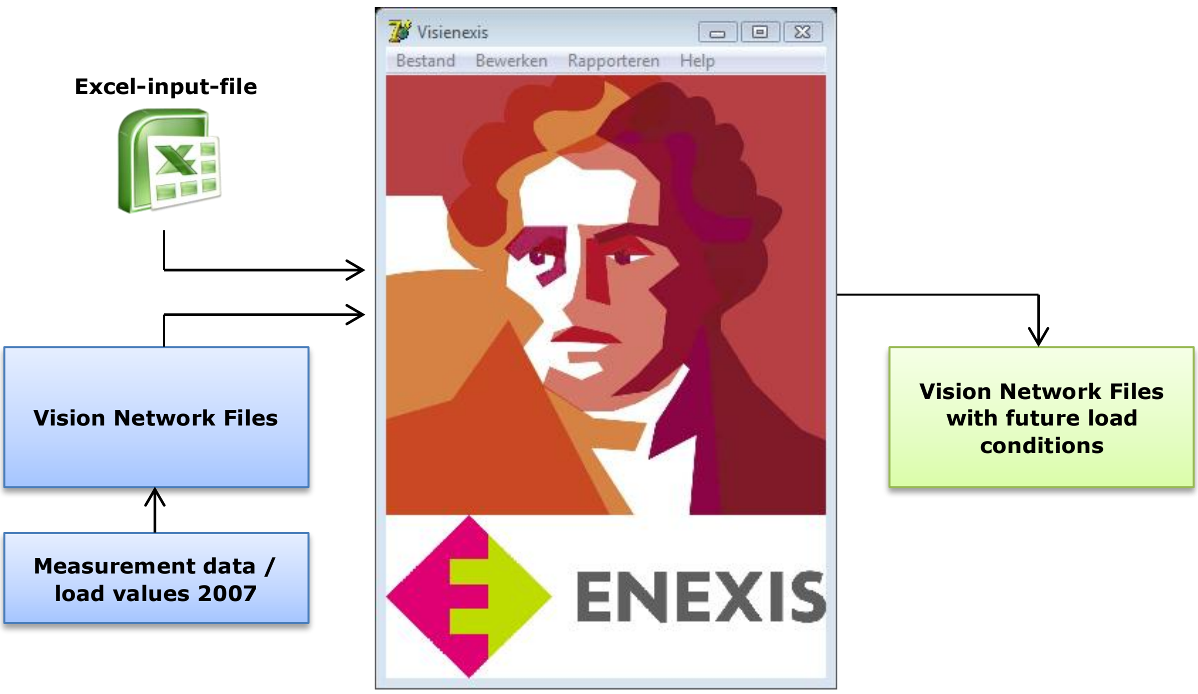

Fig. 5.1. Schematic overview: adjusting MV networks with Visienexis

Visienexis only changes the existing loads in the network to new values (load, load profile, load behaviour) representing future loads. The structure of the network and the type of assets remain the same.

The new set of adjusted simulation files are reloaded into Visienexis to perform a load-flow calculation on each network. The results for all MV-networks are exported to one Excel file. This export file contains the specifications and load-flow results of every single asset in the set of 50 MV networks (see figure 5.3). Visienexis is a stand-alone executable programme. No coupling with Vision Network Analysis is necessary to perform the load-flow calculation.

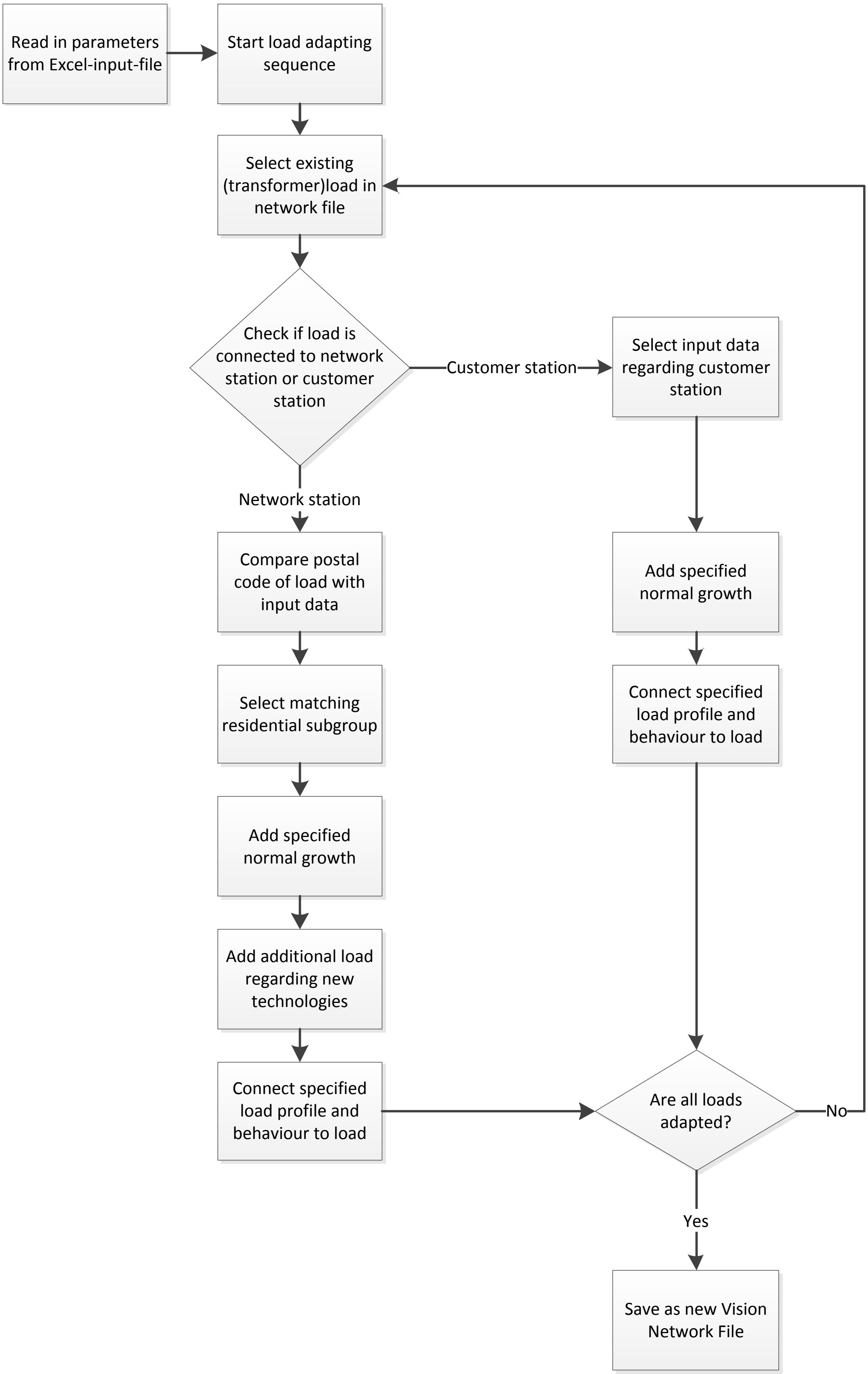

Fig. 5.2. Flow chart of load adapting method in Visienexis

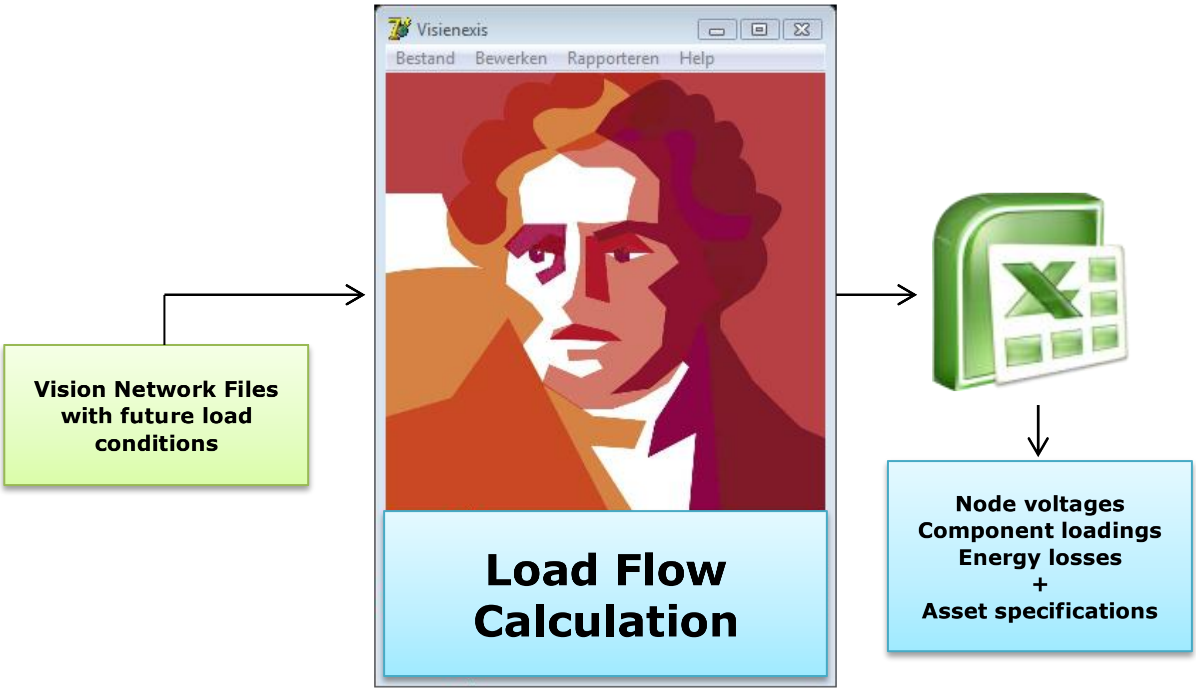

Fig. 5.3. Schematic overview: load flow calculation in Visienexis

6 Impact of Future Residential Loads

This chapter describes the impact of future residential loads on component loadings and node voltages in the MV network for the three future scenarios. The output results from the executed load-flow calculations applied to the 50 MV networks.

6.1 Component loadings

A comparison is made between the scenarios, and for uncontrolled and controlled (smart) load demand. The results will also be compared to conventional network planning results. The component loadings of four types of assets in the MV network are distinguished:

- MV/LV transformers
- MV-Distribution cables
- MV-Transmission cables
- HV/MV stations

Each network level has different overload criteria which will be clarified and described in this paragraph.

6.1.1 Uncontrolled scenarios

The set of MV networks are with the use of Visienexis adapted to future load conditions for the three scenarios without any control. The load-flow calculation gives insight in the loading of components and node voltages, corresponding to the constant impedance load model (see chapter 7). First, the results of scenario A are presented in detail and explained. Then, the total results including all the other network components are presented for all three uncontrolled scenarios. Scenario A is the scenario in 2040 with most production still at HV, a small rise in normal demand growth (0.5% per year), few DG on LV and a limited introduction of EVs and heat pumps (§4.1).

MV/LV transformers (scenario A uncontrolled):

Figure 6.1 shows a loading distribution (histogram) of the future loadings in scenario A for the total population of MV/LV-transformers. The load percentages are relative to the nominal capacities of the transformers. Loadings below 10% are left out of consideration, because these are unrealistic numbers and probably incorrect measurements or data errors in the simulation files.

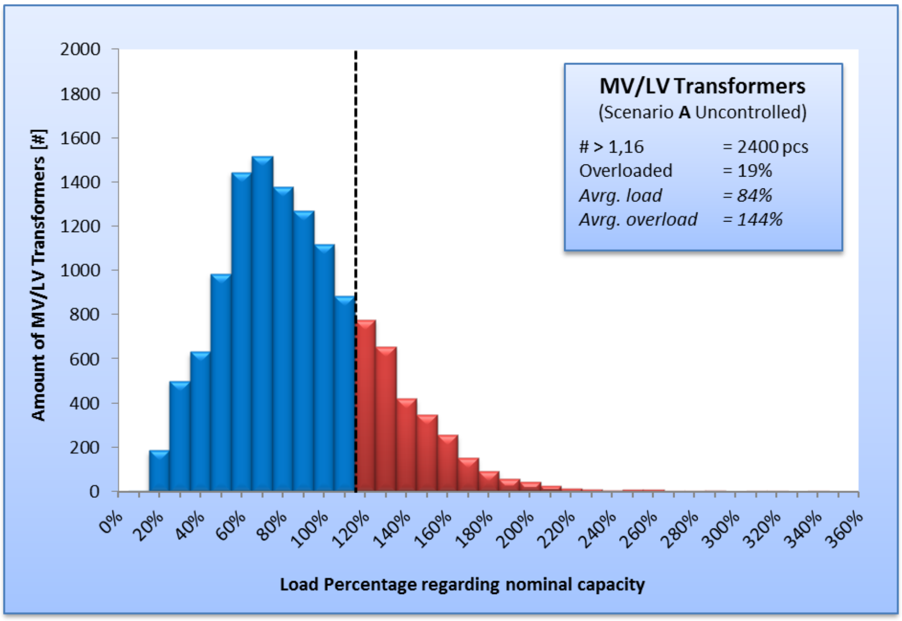

Fig 6.1: Loadings of MV/LV transformers in scenario A (uncontrolled)

The overload criterion is dependent on the load profile of the transformer. This reflects the fact that instantaneous peak values are considered and transformers can sustain a peak higher than its nominal capacity for a while without problems. With the residential load profiles of nowadays, the overload criterion according to the MV design directives of Enexis would be 1.16 for MV/LV transformers in existing residential areas (see §2.4.2). This means that MV/LV transformers with loadings higher than 116% to their nominal capacity are nowadays marked as overloaded. The overload criteria for all network levels will be fixed at the present criteria for all scenarios (in the case of MV/LV transformers: 1.16), in order to make clear comparisons between the effect on the capacities for the different scenarios. Later on it will be discussed if the overload criteria for different scenarios with different load profiles need to be changed.

The load percentages relative to the nominal capacity of overloaded transformers should not be interpreted as the actual loading the transformers will have in 2040, but rather as the loading that the transformer would have if it would not be replaced. Figure 6.1 shows that 19% of the MV/LV transformer population exceeds the threshold of 116% in 2040 for scenario A, and should be replaced before 2040 (if the overload criteria would remain the same). The average loading for the total population is 84% relative to the nominal capacity. The parameter 'average overload' indicates how 'heavily' the overloaded MV/LV transformers are overloaded, on average: this is the average loading of the transformers which are marked as overloaded (the average of the red bars). This parameter should be seen in relation to the overload criterion. The higher the 'average overload' compared to the overload criterion, the heavier the replacements which are needed. See Appendix E1 which transformer types are most overloaded.

MV-Distribution cables (scenario A uncontrolled):

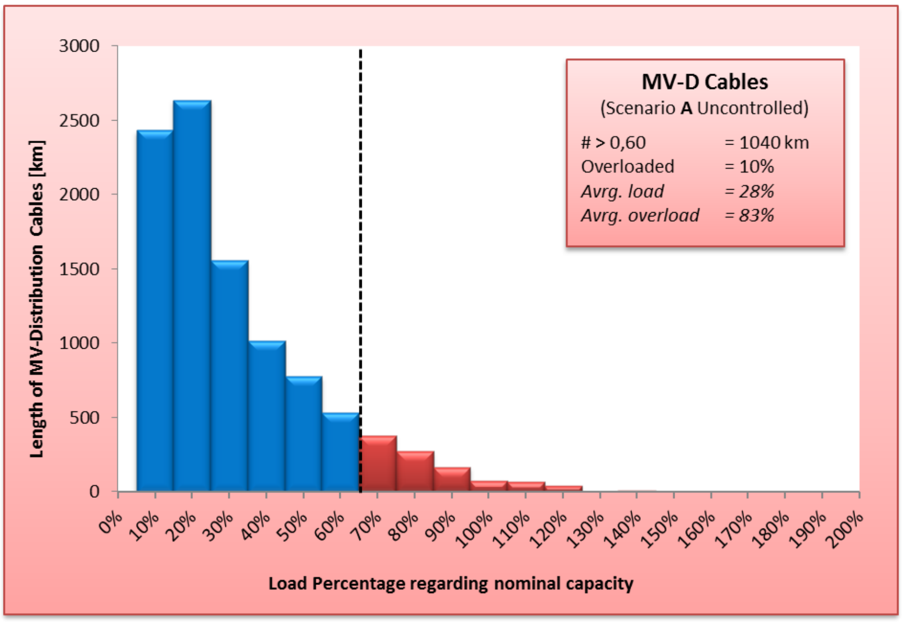

Fig 6.2: Loadings of MV-Distribution cables in scenario A (uncontrolled)

Figure 6.2 presents the loadings of MV-Distribution cables under normal operation. This means the MV-D networks are radially (star-structure) operated. During fault conditions the MV-D network might be rearranged. Under these circumstances MV-D cables are currently allowed to be 120% loaded (regarding normal capacity) for 72 hours [12]. However, Visienexis is not (yet) capable of simulating this scenario and cannot rearrange a distribution ring. Manually it is possible, but would be too cumbersome. Therefore a correction for the overload criteria under rearranged situations has been assumed in order to receive an overload criteria for normal MV-D cable operation. A correction factor of 0,5 for the overload criteria has been assumed[8]. The

[8] The NOP in an ideal distribution ring is preferably located half-way the ring, so the load would be equally divided over the two radial operated MV-D cables (e.g. cable A & B). The cable load at the beginning of the ring (cable A) should then not exceed 50% of the maximum allowed loading, because if a fault occurs at cable B near the other end of the ring, cable A needs to feed all loads connected on the total ring. So, on

overload criteria (with current load profiles) in rearranged situations is 120%, by taking into account the correction factor, the overload criteria becomes 0,6 (or 60% regarding nominal cable capacity) for normal operation.

The histogram shows that only 10% of the total MV-D cable length will be overloaded by 2040. Even though the correction factor might be different, the histogram still shows low loadings under normal operation. This means that there is still some capacity left.

MV-Transmission cables (scenario A uncontrolled):
Figure 6.3 presents the loadings of MV-Transmission cables under normal operation. MV-transmission networks normally meet the (n-1) criterion, which means that when all (parallel) cable bundle circuits are in operation, every cable circuit in the bundle can be lost without causing an overload of any other cable and without any interruption of supply. Meeting the (n-1) criterion also facilitates maintenance, as one circuit can be taken out of service for carrying out maintenance [13]. The overload criteria for MV-T cables is determined with formula 2.1, which will be presented here again.

$$I_{\max\_equal\_loaded} = I_{nom} \cdot P \cdot T \cdot D \qquad = I_{nom} \cdot 0.974$$

The P, T and D factor are determined according to the cable loading guideline in §2.4.1 and Appendix A [12,13]. The peak load in the future scenarios still occurs in winter time (determines T factor). There is assumed that MV-T bundles have on average 3 parallel cables, and most of these bundles are situated in other soils then peat (determines P factor). The D factor, to incorporate the thermal dynamics of the cable, is in this case valid for the existing load profiles. Finally, the n-1 criterion is taken into account. An additional correction factor of 0,7 is assumed[9], which result in a total overload criteria of 0,68. The histogram reveals that a large part of the MV-T cable population will be overloaded for this scenario. The capacity of this network level is much smaller compared to the 'lower' network levels.

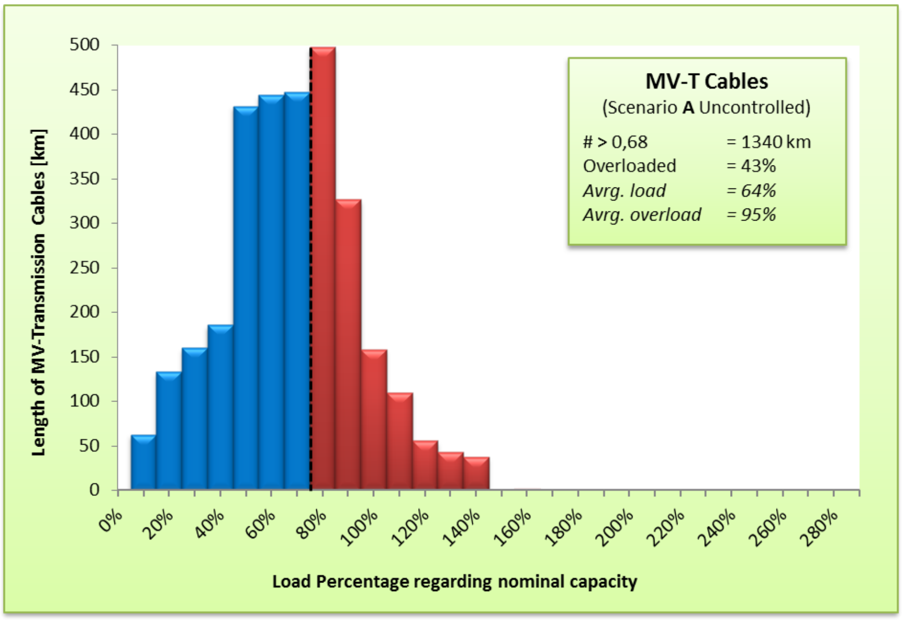

Fig 6.3: Loadings of MV-Transmission cables in scenario A (uncontrolled)

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average, the cable loading under normal operation should in general not exceed 50% of the maximum allowed loading, which result in a correction factor of 0.5.

9 This value is dependent on the configuration of the MV-T network. Visienexis is not (yet) able to recognize the structure of an MV-T network, only output of individual MV-T cables is generated. For an MV-T bundle with 2 parallel, the n-1 correction factor would be 0,5, since one of the two cables should be able to transport the total load. MV-T bundles consists on average of 3 parallel cables, but MV-T substations are mostly interconnected. The transport load can then be partly spread, therefore a factor of 0,7 is assumed.

HV/MV Stations (scenario A uncontrolled):
For HV/MV-stations the n-1 criterion is taken into account (safe n-1 capacity regarding installed capacity, see figure 6.4) and an allowed overload factor (in this case 1,2) for the HV/MV transformers regarding the existing load profiles, following the same principle applied to the MV/LV transformers. Of all network levels, HV/MV stations are subjected to the largest impact (see figure 6.5).

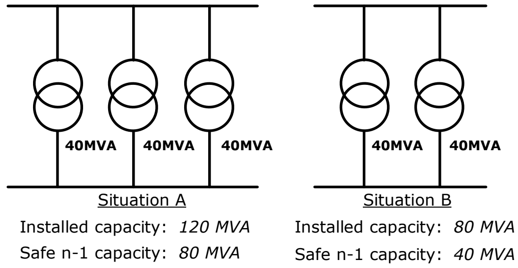

Figure 6.4: Capacity HV/MV stations

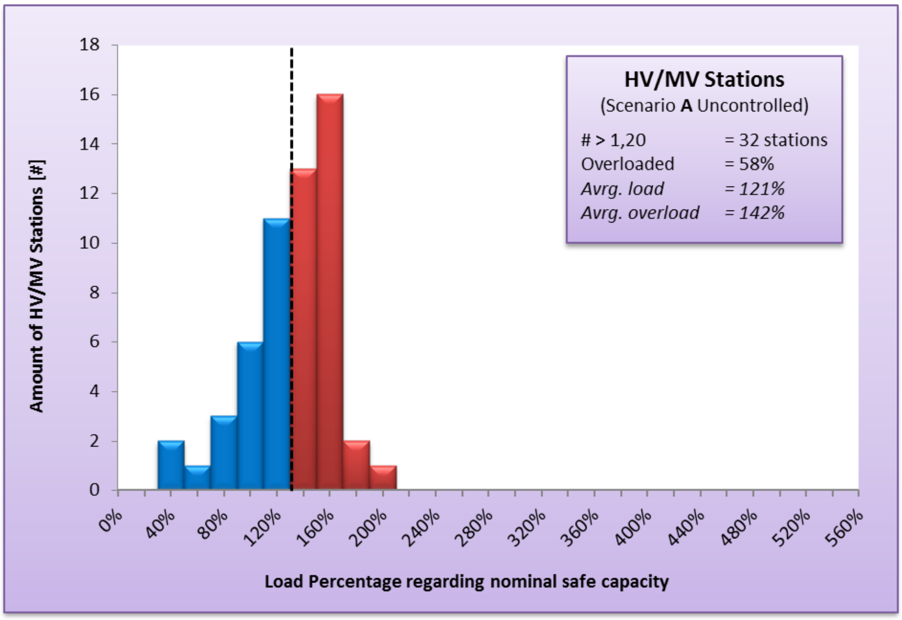

Fig 6.5: Loadings of HV/MV stations in scenario A (uncontrolled)

Table 6.1 presents an overview of the results for the uncontrolled scenarios per network component. The overload criterion per network level is also mentioned. The 1% growth scenario in the right column can be considered as a base case. This is a scenario where all loads (residential and non-residential) in the MV network grow 1% per year; this corresponds with the conventional method for network planning in existing MV networks. The component loading correspond to the constant impedance model (see chapter 7).

Table 6.1: Number of components overloaded in percentage for the uncontrolled scenarios

Network component:	Scenario A *Uncontrolled*	Scenario B *Uncontrolled*	Scenario C *Uncontrolled*	Scenario *1% Growth*
MV/LV transformers				
Numbers overloaded (#>1.16):	**19 %**	**50 %**	**36 %**	**10 %**
Average overload percentage:	*144 %*	*197 %*	*169 %*	*130 %*
MV-Distribution cables				
Numbers overloaded (#>0.60):	**10 %**	**30 %**	**20 %**	**8 %**
Average overload percentage:	*83 %*	*122 %*	*99 %*	*80 %*
MV-Transmission cables				
Numbers overloaded (#>0.68):	**43 %**	**83 %**	**72 %**	**29 %**
Average overload percentage:	*95 %*	*154 %*	*116 %*	*94 %*
HV/MV stations				
Numbers overloaded (#>1.20):	**58 %**	**91 %**	**87 %**	**45 %**
Average overload percentage:	*142 %*	*282 %*	*190 %*	*138 %*

The results show large differences between the scenarios. Scenario B causes the largest impact on component loadings, which is the result of a high demand: high penetrations of EV and heat pumps, and a substantial rise in 'normal' demand (2% per year). Scenario A has a relative low impact (small demand growth) and results of Scenario C are in between (also caused by high penetrations of EVs and heat pumps, but in this scenario the rise in 'normal' demand is smaller).

All three scenarios show large impacts on the MV-Transmission level and the HV/MV stations. Large reinforcements will be necessary at these network levels, which are most costly. The reason of high investment costs at these levels is also the main reason why the (remaining) capacity is quite narrow. The capacities are based on the existing load situation, and (large) investments are postponed as long as possible. The components lower in the network have more available capacity.

Scenario B and C show large differences compared to the 1% growth scenario, the conventional network planning method. If this conventional method would still be applied, a large error in the expecting overloads may resolve in an inefficient replacement strategy.

6.1.2 *Controlled (smart grid) scenarios*

Table 6.2 shows the results of the controlled scenarios, where the residential future loads and generators are controlled, e.g. using not time-critical loads like EVs by applying smart charging. The base case (1% growth scenario) in the right column is presented again, and the overload criteria haves remained the same. Figure 6.6 visualises the overload percentages of both controlled and uncontrolled scenarios. Caution: the 'depth' of the overload (*average overload percentage*) cannot be distinguished from these figures.

Table 6.2: Number of components overloaded in percentage for the controlled scenarios

Network component:	**Scenario A** *controlled*	**Scenario B** *controlled*	**Scenario C** *controlled*	**Scenario** ***1% Growth***
MV/LV transformers				
Numbers overloaded:	**6 %**	**32 %**	**14 %**	**10 %**
Average overload percentage:	*125 %*	*161 %*	*140 %*	*130 %*
MV-Distribution cables				
Numbers overloaded:	**5 %**	**23 %**	**12 %**	**8 %**
Average overload percentage:	*77 %*	*104 %*	*84 %*	*80 %*
MV-Transmission cables				
Numbers overloaded:	**18 %**	**76 %**	**46 %**	**29 %**
Average overload percentage:	*92 %*	*125 %*	*96 %*	*94 %*
HV/MV stations				
Numbers overloaded:	**20 %**	**91 %**	**67 %**	**45 %**
Average overload percentage:	*126 %*	*216 %*	*149 %*	*138 %*

Most notable is the fact that in all scenarios the percentages of overloaded components has significantly reduced by applying control to residential loads and generators. Not only the percentages of overloaded components have become smaller, but also the 'average overload percentages'. This means that the components that are marked as overloaded, are not that heavily overloaded as compared to the uncontrolled cases, and lighter replacements (and thus lower investments) are possible.

Especially scenario A shows significant differences. The loading of the components are even less than the loadings in the 1% growth scenario. Scenario C also shows some savings, but the effect for scenario B is not impressive. The reason for this is the substantial rise in 'normal' demand (2% per year). The effect of this growth factor on the existing (peak) load is dominant with regard to the reduction in peak load due to smart control. The peak load will therefore rise substantial in both cases (controlled and uncontrolled). For the MV/LV-transformer level this effect has less influence, but on higher network levels where mainly large non-residential loads (e.g. industry) are connected (to which no control is applied in this study), the growth factor implies a substantial rise in peak load. So the 'normal' growth factor becomes dominant and damps out the effect of controllable residential loads and generators on the higher network levels.

Because these large demand growths have such an impact, it is interesting for further research to verify if these large growth factors for non-residential loads on the existing MV networks are realistic and above all to investigate the potential of control of these non-residential loads.

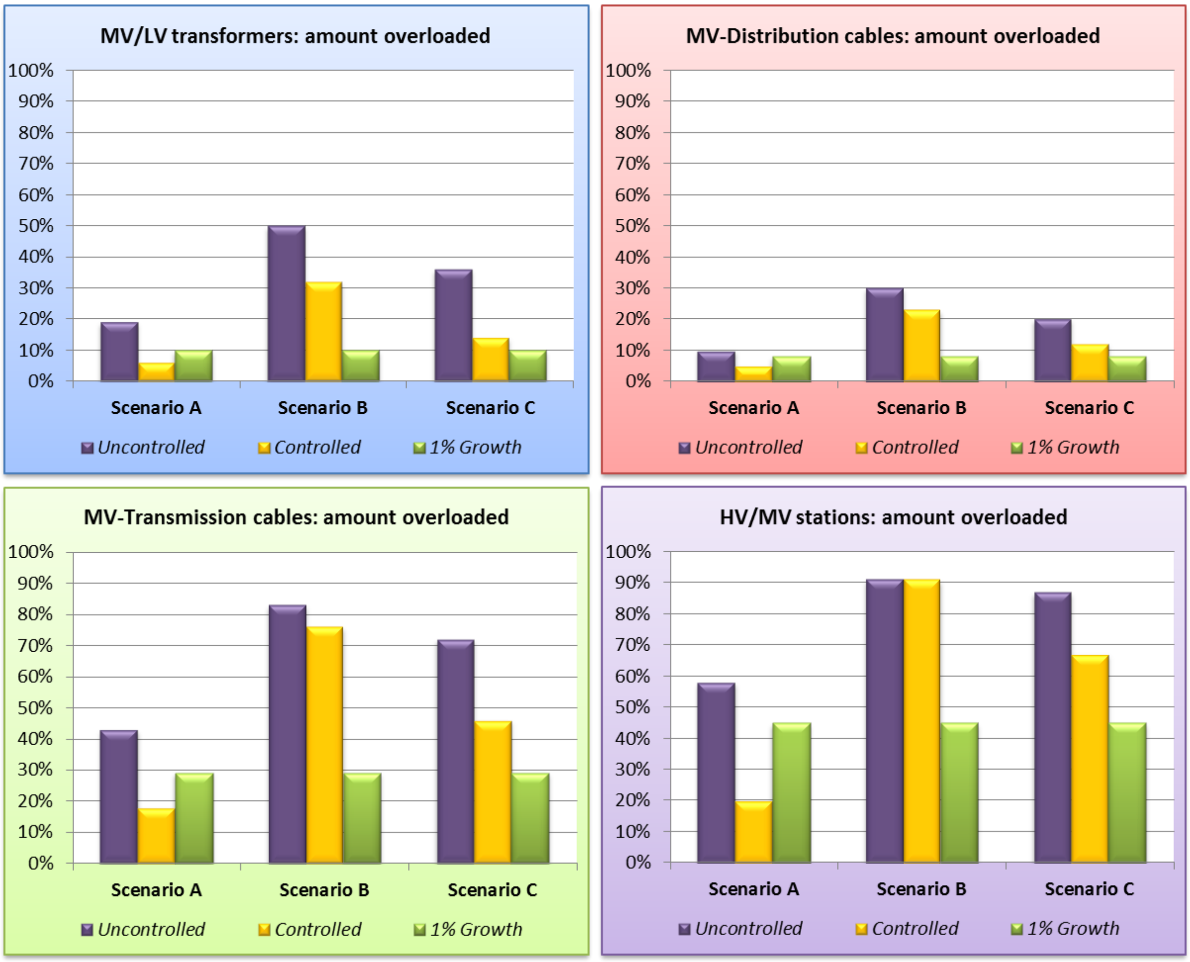

Fig 6.6: Component loadings for both controlled and uncontrolled scenarios

6.2 Node voltages

The load-flow calculations done in this study have been used to calculate the loadings in 2040, but the assets in the networks have not been reinforced. The substantial amount of overloaded components result in additional voltage drops and unrealistic node voltages. Therefore, the voltages calculated in the load-flow do not match the actual voltages in 2040.

Further research is needed to check if voltage deviations in future scenarios stay within the specified range (§2.4.3). The network should first be reinforced to meet the new future demands and loading criteria. The voltage deviations should only be studied after this step. This research might result in necessary additional network extensions to keep the voltage for the total network within the specified limits. These results are of importance for network planning and investment analysis.

6.3 Conclusions

The results from the executed load-flow calculations applied to the 50 MV networks show large differences in component loadings between three different future scenarios. All three scenarios do

show large impacts on the MV-Transmission level and the HV/MV stations. Scenario B causes the largest impact on component loadings, which is the result of a high demand.
Most notable is the fact that in all scenarios the percentages of overloaded components have significantly been reduced by applying control to residential loads and generators, especially in scenarios where the dominance of the 'normal growth factor' is relatively low (e.g. scenario A).
However, the overload criteria for all network levels in the above cases are fixed at the present criteria. The criteria are valid for existing load profiles. The existing load profiles for the three future scenarios will change as shown in Figures 4.1 and 4.2, which might result in different overload criteria. For the controlled scenarios the load becomes more continuous and the ratio between peak and base load has become smaller. Assets become less capable of handling loadings above nominal capacity, since there will be less time for cooling down. This would result in a reduced life expectancy of the asset. Therefore, the overload threshold probably needs to be corrected downwards. In case of uncontrolled load profiles in the three future scenarios there is a large variation in load, even larger than for the existing profiles. This might result in a positive correction of the overload criteria.

The changing load profiles and the differences between controlled and uncontrolled profiles, will also have effect on the energy losses in the network. All these kinds of issues are important for further research and investment analysis.

7 Load behaviour and voltage collapse

This chapter discusses the influence of load behaviour/characteristics on the results of the load-flow calculation and on the stability of the power system. The loads connected to the distribution system are voltage dependent. Assuming a 'wrong' load behaviour in the load-flow calculation, can therefore result in different voltages and component loadings for the same network. It might even result in stability problems where the voltage collapses. The load-flow situation will then diverge and no output can be generated.

First, some information on basic load modelling concepts will be explained followed by how the loads can be modelled in Vision/Visienexis. Finally, the influence of different load behaviours on the set of 50 MV networks for different future scenarios is discussed.

7.1 Basic load-modelling concepts

Stable operation of a power system depends on the ability to continuously match the electrical output of generating units to the electric load on the system. Consequently, load characteristics have an important influence on system stability. The modelling of loads is complicated because the load, for example of the MV/LV transformer, is composed of a large number of devices such as fluorescent and incandescent lamps, refrigerators, heaters, compressors, motors, furnaces, and so on. The exact composition of load is difficult to estimate, also because the composition changes on time (seasons). Therefore load representation in system studies is based on a considerable amount of simplification [18].

The power and load consumed by a load, may depend on the applied voltage and frequency. Since in load-flow calculations the frequency is kept constant, only the voltage dependency is a part of the load model. Some loads are purely resistive, others draw a constant power and many loads have a behaviour which is a combination of both. In order to cope with this voltage dependency different models can be applied to the loads [9].

Standard load behaviours are:

- Constant power: the active and reactive power of the load are independent of the applied voltage. This implies that a decrease of voltage results in an increase of the current drawn by the load.
- Constant current: the current drawn by the load is independent of the applied voltage. The power is linearly dependent of the actual voltage.
- Constant impedance: the power is quadratic dependent of the actual voltage. The current drawn by the load decreases when the voltage decreases.

Load models are classified into two broad categories, static models and dynamic models[10]. Traditionally, the voltage dependency of load characteristics has been represented by the *exponential model* [18], which is a static load model:

$$P = P_0\left(\frac{V}{V_0}\right)^a \quad , \quad Q = Q_0\left(\frac{V}{V_0}\right)^b \qquad (7.1)$$

where P and Q are active and reactive components of the load when the voltage magnitude is V. The subscript 0 identifies the value of the respective variables at the initial operation condition. The parameters of this model are the exponents a and b. With these components equal to 0, 1, or 2, the model represents constant power ($a=b=0$), constant current ($a=b=1$), or constant impedance characteristics ($a=b=2$).

Table 7.1 describes the load characteristics for a number of load classes[11] including the power factor. Table 7.2 shows typical values of a and b for several types of loads encountered in power systems; it is interesting to note that none of these loads have a zero exponent (constant power).

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10 Dynamic models are used for studies of inter area oscillations, voltage stability, and long-term stability.

11 It should be noted that these values are composed in 1994. The present load characteristics might be different.

Table 7.1: Sample characteristics[12] of different load classes [18]

Load class	Power factor	a	b
Residential	0.95	1.4	2.0
Commercial	0.90	1.3	2.0
Industrial	0.85	0.2	2.0
Power plant auxiliaries	0.80	0.1	1.6

Table 7.2: Typical static characteristics of components [18, 21]

Component	Power factor	a	b
Water heater	1.00	2.00	-
Incandescent lights	1.00	1.55	-
Air conditioner	0.82	0.50	2.00
Fluorescent lights	0.90	0.96	2.00
Dishwasher	0.99	1.80	2.00
Refrigerator	0.80	0.77	2.00
Fan motors	0.87	0.08	1.60
Industrial motors	0.88	0.07	0.50

7.2 Load modelling in Vision

The load behaviour in Vision is defined separately, and can be used for several (transformer) loads. Vision uses four parameters for the modelling of the load behaviour [16]:

For active power:
- *const.P [%]* percentage of constant power
- *const.R [%]* percentage of constant impedance

For reactive power:
- *const.Q[%]* percentage of constant power
- *const.X[%]* percentage of constant impedance

Only the parameters *const.P* and *const.Q* can be set[13]. The values for these parameters can vary between 0% and 100% and function as a percentage of constant power. The three standard load behaviours can be modelled as:

- Constant power: 100% *const.P* and 100% *const.Q*
- Constant current: 50% *const.P* and 50% *const.Q*
- Constant impedance: 0% *const.P* and 0% *const.Q*

The parameters from table 7.1 and 7.2 can be applied as follows:

$$Const.P = \left(1-\frac{a}{2}\right)\cdot 100\% \quad , \quad Const.Q = \left(1-\frac{b}{2}\right)\cdot 100\% \qquad (7.2)$$

7.3 Load behaviour in load-flow studies

Most conventional load flow studies for network planning use a constant power load model. This results in the most conservative results [9]. However, this representation may cause convergence problems in load-flow calculations. When loads are represented with a constant power behaviour, a low voltage results in an increase of the current drawn by the load. This results in a further decrease of the voltage, which might result in a 'voltage collapse'. In this way the load-flow solution diverges. When the loads are represented as constant impedance, this effect will not occur.

[12] The *a* and *b* exponent are in some cases (table 7.1 and 7.2) larger than 2. For the stated load model in combination with the load modelling possibilities in Vision , these values are simplified and capped on 2.
[13] The parameters *Const.R* en *Const.X* are always equal to respectively: 1-*Const.P* and 1-*Const.Q*.

These effects are also noticed in the case study. Some future scenarios (especially scenario B) modelled with the constant power model result in divergence of the load-flow solution. The combination of high demand, overloaded components (causes an additional voltage drop, see §6.2) and constant power load behaviour leads to this. Increasing the proportion of constant impedance in the load behaviour will increase the chance of convergence. Therefore, all future scenarios (for consistency) have been modelled with the constant impedance load model. However, the representation of load behaviour influences the values of the calculated voltages and component loadings and in this way the need for network extensions. Therefore, investigation of different load behaviour on the set of MV-network for different scenarios is necessary.

If the total set of MV networks is modelled with a constant power load behaviour, about 50% result in convergence problems. This is the case for scenario B uncontrolled. The MV networks without problems are compared to the same networks, but modelled with a constant impedance load behaviour. The comparison concerns only component loadings, since the node voltages are not realistic for 2040 (see §6.2).

Calculations show that most deviations in component loadings (between the two behaviours) stays within tolerances of ±10%. The component loadings for scenario B presented in chapter 6 (constant impedance behaviour) are on average 3-7% lower regarding the constant power load model. Remarkable is however; the component loadings in scenario A and C are on average higher (2-4%) than for the constant power load model. This means that the constant power load model is in case of scenario A and C less conservative regarding component loadings. The reason for this is that the voltage in the MV network stays on average above the nominal voltage[14]. In the constant power model this does not change the power of the load, so the current drawn by the load becomes smaller. However, in case of the constant impedance load model, the current will rise when the voltage is above the nominal voltage (of the node). This higher current results on average in a higher loading of the components.

7.4 Conclusions

Most conventional load flow studies for network planning use a constant power load model, which assumes that active and reactive powers are independent of voltage changes. In reality, constant power load models are highly questionable in distribution systems, as most nodes are not voltage controlled compared to for example HV transmission systems (voltage regulation of HV/MV transformers). Besides, the load characteristics of components in load classes in table 7.1 and 7.2 show that none of the components behaves purely as a constant power. This representation may also cause convergence problems in load-flow calculations. A low voltage results in an increase of the current drawn by the load. This results in a further decrease of the voltage, which eventually results in a 'voltage collapse'.

These effects are also noticed in the case study. About 50% of the networks have convergence problems for scenario B. The combination of high demand, overloaded components and constant power load behaviours, leads to this. Therefore, all future scenarios have been modelled with the constant impedance load model. However, the representation of this load behaviour results in different component loadings and in this way the need for network extensions.

Calculations show that most deviations in component loadings (between the two behaviours) stays within tolerances of ±10%. The component loadings for scenario B are on average 3-7% lower regarding the constant power load model. The constant power load model is in case of scenario A and C less conservative regarding component loadings. The reason for this is that the voltage in the MV network stays on average above the nominal voltage, which results in higher currents (loadings) in case of constant impedance load behaviour.
The actual load behaviour of loads in the MV network is related to the actual node voltages and component loadings. The real values will always be somewhere between the constant power and constant impedance load model.

[14] Under normal operation this is the case. The voltage in for example a 10kV network is most times about 10.5kV. Node voltage in scenario B are however relative low because of the high demand and additional voltage drop due to overloaded components.

8 Energy Loss Estimation

This chapter describes a method for the estimation of future energy losses. Energy losses are in general dependent on the network structure, type of assets and the network load. Determining the energy losses in components is essential for network planning and investment analysis, since energy losses are yearly costs for the DSO. Network planners will try to minimize the investment costs including the capitalized energy losses when reinforcing the network.

First, some general information and aspects of energy losses are describes. §8.2 shows an example of how the losses can be estimated in future residential areas with large penetrations of EVs. Eventually it is determined how the energy losses for the three future scenarios can be estimated

8.1 Network Losses

Transport and distribution of electrical energy coincide with grid energy losses and transformer losses. These losses are the difference between (centralised and distributed) generated energy and the eventually consumed energy of consumers. The network loss percentage in the Dutch grid is about 4-5% of the total electricity production[15]. The lower the grid level (HV→ LV), the higher the network losses. The loss percentage in for example the LV-network is about 7–8% [22].
The losses can generally be divided into technical losses and non-technical losses. Technical losses are caused by current and resistance (I^2R), hysteresis, eddy currents and dielectric losses (see §8.1.1). Non-technical losses are for example caused by metering errors, billing cycle errors and unmetered energy use of companies/customers that is (accidently) not measured. In the design of distribution network infrastructures the indicated technical losses are taken into account. These losses have a cost and environment aspect. The costs of network losses are dependent on the fuel prices. By capitalising the losses and/or annual returning costs, the profitability of investments can be checked. The network losses in a grid are crucial for investment analysis, but are complex to determine. Only with historical data for each day it is possible to make a really good assumption of the network losses. Therefore, the network planner will also need to use common sense to estimate future energy losses [23]. Non-technical losses are not considered for network planning.

8.1.1 *Determination of energy loss*

The determination of energy loss of a network can be done in many ways [23]. The methods can be distinguished by their level of complexity, data acquisition, accuracy and whether the period under review is in the past or future. Determining energy losses by measurements is theoretically a rather simple task for existing networks (when all network information is present), but can still only be applied to past periods. Determining the energy by computation with a network simulation program is done by dividing the time period under review (e.g. 1 year) into time segments (e.g. 15 minutes), obtaining the data for the loads for each time segment and computing the power loss for each time segment with a network computation program. This method is also applied at Enexis [24]. For these calculations many data need to be collected, which is very time consuming, and sometimes not even possible. Ideally, the load curves for all customers connected to the networks and at all MV (sub)stations would be needed. This information is not available for the set of MV networks under analysis. In MV networks typically only the peak current is measured at the MV/LV transformers. In low voltage networks mostly there is no current measurement at all.

In the next paragraphs a method will be described how to estimate the energy losses in the existing MV network, and how these will change with future load profiles in a controlled and uncontrolled scenario.

8.1.2 *Technical Losses (in cables and transformers)*

Technical losses are typically divided into load dependent losses (*copper losses*) and not load dependent losses (*iron losses*). Load dependent losses are a function of current and resistance and not load dependent losses are a function of voltage and frequency. Since the grids run at a

[15] Which represents 4768.000.000 kWh in 2008 [www.cbs.nl]

nearly constant voltage and a fixed frequency of nearly 50Hz, the no-load losses are also nearly constant. In contrast, the load dependent losses are not constant and vary according to the loading of the equipment.
In cables 'dielectric' losses exist in the insulation and 'corona' losses, but these are negligible compared to the copper losses in the conductor, which let the temperature rise in the cable rise. The copper losses are quadratic proportional to the current flowing through the conductor, and linear proportional to the resistance of the conductor (I^2R). The resistance depends on the surface area and type of conductor. Copper has a better conduction (i.e. lower resistance) than aluminium[16].

Transformers do have copper losses (dependent on the load) and iron losses (independent on the load). The copper losses are caused by heat losses in the windings of the transformer, and dependent on the load current, just as for the conductor of a cable. The iron losses include 'hysteresis' losses (*linear proportional with the frequency*) and 'eddy current' losses (*quadratic proportional with the frequency*) which arise in the magnetic core/circuit of the transformer. Measurements have shown that the iron losses are quite dependent on the voltage: at the medium voltage level, almost 30% higher iron losses have been measured due to a voltage rise of 7,5% [12]. In this study it is assumed that the iron losses are constant and the values given by the supplier of the transformer will be used. Despite of all the losses, the transformers still have an efficiency of higher than 98%. Larger transformers are generally more efficient than distribution transformers [25].

Table 8.1: Losses of Oil Transformers (Norm 1995)

Nominal Power	*Nominal Iron Losses*	*Nominal Copper Losses*
[kVA]	[W]	[W]
50	115	840
100	190	1350
160	260	1905
250	365	2640
400	515	3750
630	745	5200

Table 8.1 shows default iron and copper losses of the so-called 'norm 1995' oil-distribution transformers[17]. These are the standard types used by Enexis. The indicated copper losses are losses at full load. At lower loadings of the transformer the copper losses drop quadratic, because of the quadratic dependence of the load. In formula form:

$$P_{copper} = \alpha^2 \cdot P_{copper\_nominal} \tag{8.1}$$

α = Load percentage of transformer [%]

The focus for the energy loss estimation is on the load dependent losses. They depend on the load characteristics/profile. The load profiles will change in future scenarios and therefore also the energy losses. Load and generation control in smart scenarios result in more constant load profiles. This will have a different effect on the losses than for uncontrolled load profiles.

8.1.3 Estimation of load dependent losses

Load dependent losses are quadratic dependent on the network load (I^2R). At peak load moments there are most losses, the so-called peak losses. The peak load for the maximum load situation in the year is simulated with Visienexis. The maximal peak losses can be calculated from here. The rest of the year the losses are fluctuating somewhere below this peak loss. The profile of this fluctuation is called the energy loss profile and is related to the load profile. The area below the maximal peak loss, caused by the loss profile, is called the service time of the peak loss.

The energy loss profile will result, because of the quadratic dependency, in a different shape than the load profile. The area of the load profile will be larger than the area of the energy loss profile, when both profiles are normalized regarding their peak load / peak energy loss. Figure 8.1 shows an example of an average residential *load profile* and the corresponding *loss profile*. The *normalized* energy loss profile is the square of the *normalized* load profile. The area of the loss profile is about 70% of the area of the load profile. These areas are related to the service time of the peak load T_b *[hours/year]*[18] and the service time of the peak loss T_v *[hours/year]*[19]. The peak loss is the loss during peak load.

[16] Although aluminum cables have higher losses then copper cables, almost all DSO's currently invest in aluminum cables due to a much lower price of raw material.
[17] The previous norm was 1991. These transformers had lower copper, but higher iron losses.
[18] Can maximal be the number of hours in one year: 8760

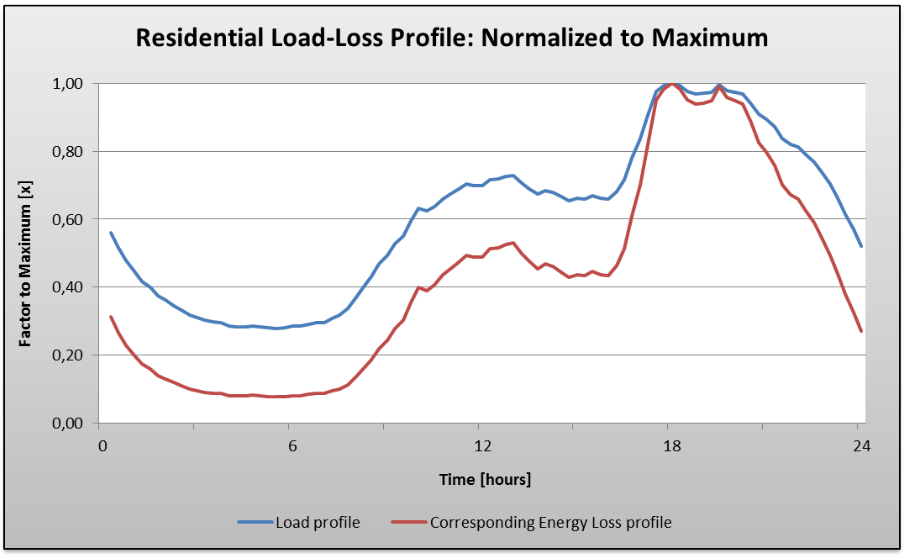
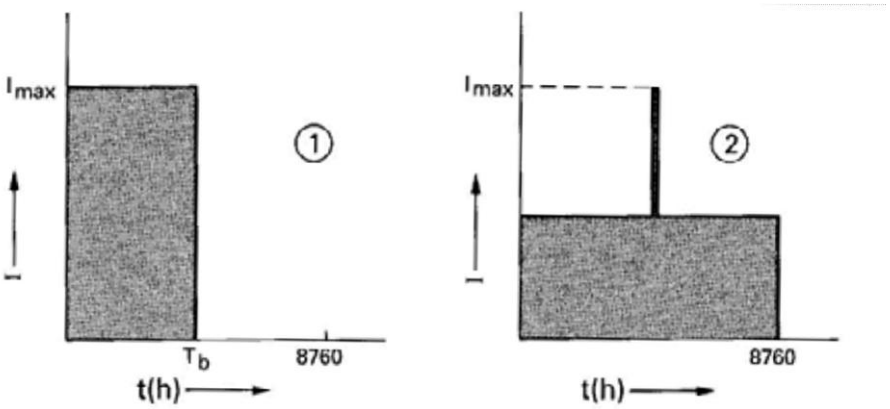


Fig 8.1: Shape of a residential (normalized) load profile on December 1st and corresponding energy loss profile

The relation between the service times T_b and T_v is dependent on the shape of the load profile. In figure 8.1 the service time of the peak loss is equal to 70% of the service time of the load. The theoretical limitations for this relationship are visualized in figure 8.2 [22] with two extreme situations.



Situation 1:

$$T_v = T_b$$

Situation 2:

$$T_v = \frac{T_b}{8760} \cdot T_b$$

Figure 8.2: Two extreme load profiles with the same energy needs [22]

In the first situation the service time of the peak loss is maximal (in comparison to the service time of the peak load), and in the second situation minimal. Figure 8.3 shows the borders of T_v as function of T_b. One conclusion is that T_v can never be greater than T_b. The following coherence between the two service times (for a specific load profile) on annual bases can be derived:

$$T_v = C \cdot T_b + (1 - C) \cdot \frac{T_b^2}{8760} \quad \text{with} \quad 0 \leq C \leq 1 \qquad (8.2)$$

Measurements show that the C In LV-networks is mostly 0,1…0,2 [20]. In the existing distribution networks T_v is closer to boundary 2 than to

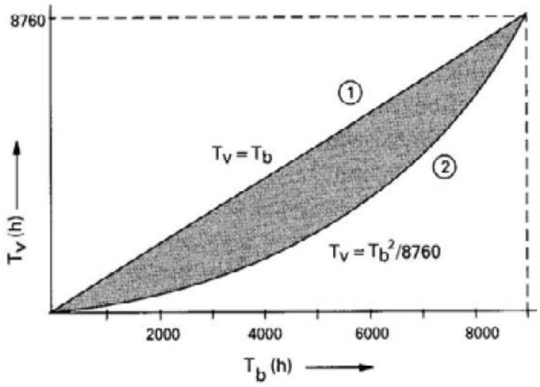


Figure 8.3: Relation between T_v & T_b

[19] The iron losses of the transformer shouldn't be taken into account for the calculation of T_v. These losses are not proportional with the square of the load, but are dependent on the operation (switched-on) time of the transformer.

boundary 1. This is due to the fact that for load curves with relative short peak loads compared to the overall day load, the peak load has relatively low impact on the losses.

8.1.4 *Analyzing standard residential load profiles*

For the Dutch branch organisation EnergieNed, normalized aggregated residential load profiles are created. These profiles are available for Dutch energy suppliers and network operators. To compose the load profiles load measurements of 400 households have been used with a 15 min interval. By normalizing all measurement values[20] to the maximum value a year, results in factors *F* regarding P_{max}:

$$F_n = \frac{P_n}{P_{\max}} \qquad \text{with} \quad 0 \le x_n \le 1 \text{ and } \quad 1 \le n \le 35040 \tag{8.3}$$

With these normalized factors regarding P_{max} it is possible to determine the service time (T_b) of the peak load (P_{max}):

$$T_b = \frac{\sum_{n=1}^{35040} F_n}{4} = 4300 \left[hours / year \right] \tag{8.4}$$

Because the factors *F* are normalized values, it is easy to calculate the service time (T_v) of the peak loss by taking the square of every factor *F*:

$$T_v = \frac{\sum_{n=1}^{35040} F_n^2}{4} = \mathbf{2350} \left[hours / year \right] \tag{8.5}$$

The minimal T_v for the corresponding T_b is:

$$T_{v\_\min} = \frac{T_b^2}{8760} = 2110 \left[hours / year \right] \tag{8.6}$$

By restructuring formula 8.2 it is possible to determine *C*. This value becomes *C*=0,11 with the related T_b, which is comparable with results from other measurements [20].

Residential profiles from the report *Hermes DG3* [26] have also been analysed. This measurement took place in a residential area (250 households) for one year (2007) with a 10min interval. The results of the two analyses are summarized in table 8.2.

Table 8.2: Service times of residential load profiles in hours/year

Source	Service time of load T_b	Service time of losses T_v	Corresponding value of C	Minimal T_v
EnergieNed profiles:	4300	2350	0,11	2110
Hermes DG3 profiles:	4040	2070	0,11	1860

The difference in service times between these two analyses is due to the fact that the ratio between maximal measured load (peak load) and the average load during one year is lower for the Hermes DG3 profiles. Calculations show a '*peak load vs. average load*' ratio of 2.24 for the Hermes profiles, so the measured peak load is 2.24 times higher than the average load, and 2.04 for the EnergieNed profiles. A higher ratio results in lower service times. This ratio difference can e.g. be caused by differences in seasons (cold winter times vs. soft winter times).

Table 8.3: T_v, based on measurements

Network level	Service time of peak loss T_v
MV/LV transformers:	1500-2000
MV-distribution cables:	2000-3000
MV-transmission cables:	2500-3000
HV/MV transformers:	3000-3500

This short analyses show that a *C* around 0,1 is valid for the service time of the energy losses at MV/LV transformer level. It is however difficult to determine the service time of the load in the desired load-flow analysis, because not every (or

[20] This amount is equal to the number of quarters in one year: 35040

multiple) daily load profile(s) of the year is known. And when T_b cannot be defined it is useless to know C. Therefore, the service time of the energy losses per network level is estimated. Table 8.3 shows average service times at different network/component levels. The values calculated above are valid for the MV/LV transformer level and seem to be comparable with the values in table 8.3. The different T_v's in table 8.3 can be used to make a estimation of the total energy loss in a network.

The total energy loss can be calculated per network component (e.g. transformer) with the formula below:

$$E_{loss} = P_{iron} \cdot T_i + P_{copper} \cdot \alpha^2 \cdot T_v \qquad (8.7)$$

E_{loss} = Total energy loss of a transformer [kWh/year]
P_{iron} = Iron losses [kW]
T_i = Operation / Switched-on time of transformer [8760 hours/year]
P_{copper} = Copper losses at nominal power [kW]
α = Load percentage of transformer (quotient of peak load and nominal power) [%]
T_v = Service time of peak loss [hours/year]

The load-flow calculations give information about node voltages, component-loads (peak load and percentage of nominal power) and peak losses. The resulting peak losses from the load-flow can be multiplied with different service times T_v (estimated per network level) to receive the total energy losses.

8.2 Changing Energy Losses due to large penetrations of Electrical Vehicles

This paragraph describes an example for the estimation of the energy losses in residential areas with high penetrations of electrical vehicles (EVs). This is done to explain the influence of changing load profiles on energy losses. First, the service time of the energy losses will be estimated with the same method as in §8.1. An example shows how to calculate the losses in a transformer and finally, the combined effect of peak loss and service times becomes clear.

8.2.1 Changes in the Load Profile

The charging of EVs by the grid has influence on the shape and peak of the residential load profiles. The changes depend heavily on the type of charging. Reference [26] shows how different charge profiles for EVs can be derived from transportation data. The changing energy losses will be identified for two types of charging strategies:

- Uncontrolled charging (10kW)
- Controlled (smart) charging

The data of [27] is used to create new aggregated load profiles of households including EVs. Figure 8.4 shows new aggregated load profiles for a situation in 2040, where 75% of the households have one EV [28, 29]. The base here is the 'normal' residential load profile of December 1st (black dotted line). The parameters that are used to build up the profiles are summarized in table 8.4.

Table 8.4: Properties of residential area with EV

Parameter	Value
'normal' annual electricity demand:	*3400kWh*
'normal' (demand) growth:	*1% per year*
'normal' growth period:	*30 years*
Penetration degree of EV:	*75 %*
Average daily driven distance:	*35 km/day*
EV efficiency:	*5 km/kWh*

First, the normal residential profile with a growth of 1% per year for 30 years is shown (red line). On top of this profile the EV charge demand is visualized for two variants: uncontrolled (green line) and smart charging (purple line). In the uncontrolled variant there is a large evening peak in the demand, which results from the distribution in home arrivals [27]. In the smart charging variant the EV demand is shifted to the night hours where the demand for household electricity is the lowest. The change in peak load is very small in comparison to the uncontrolled charging variant.

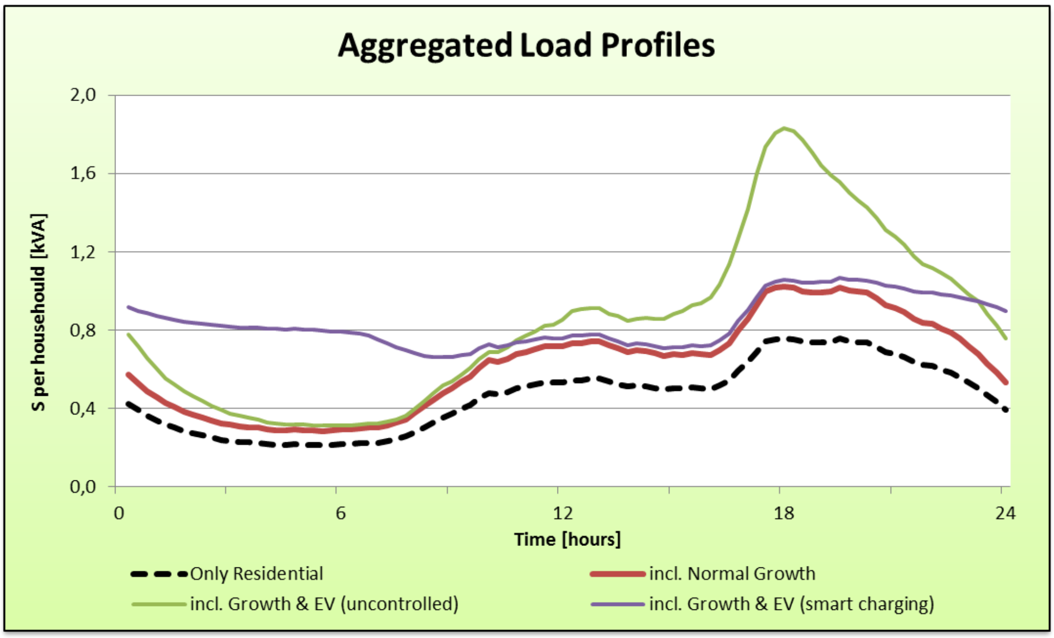


Fig 8.4: Aggregated residential load profiles with EVs (normalized to one household)

8.2.2 Changes in the Loss Profile

The loss profiles of households with EVs will significantly change due to the changes in the load profile. The load profiles first need to be normalized to their peak values and then be squared to create the loss profiles. Figure 8.5 visualizes the loss profiles of the corresponding load profiles.

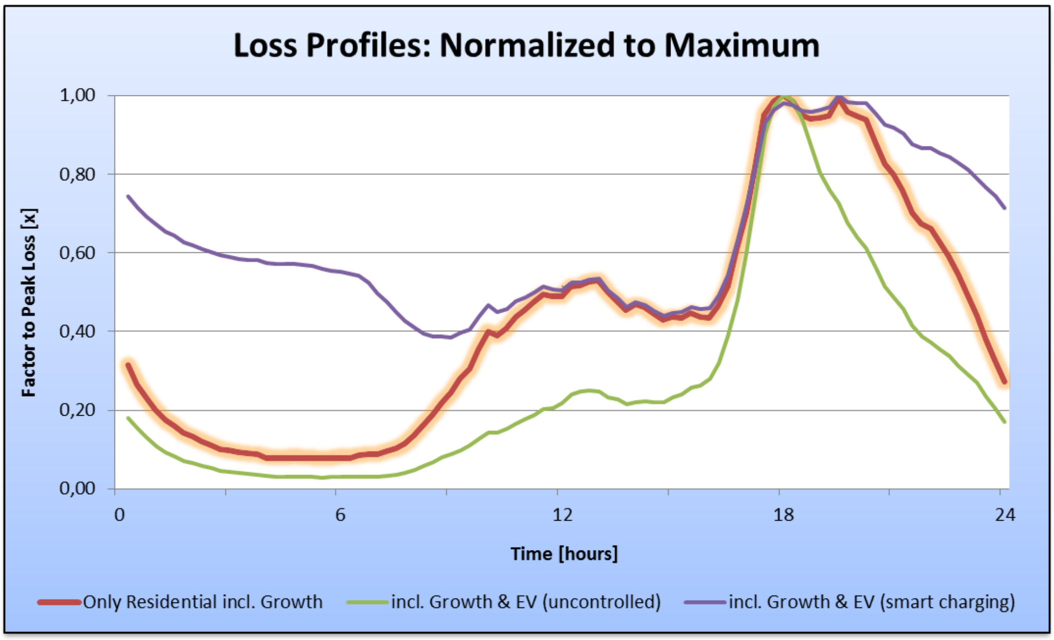


Fig 8.5: Loss profiles of corresponding residential load profiles with EVs

The standard residential loss profile has the same shape as in figure 8.1. The included normal growth does not affect the normalized loss profile because the shape of the load profile does not change and is only scaled in height. The loss profile of a household with uncontrolled charging of EVs (green line) has a much smaller area beneath the graph than a normal household. This is the result of a large variation in load. For the controlled/smart charging variant it is the other way around: the load becomes more continuous and the ratio between peak and base load has become smaller.

8.2.3 *Effect on service times and total energy losses*

The areas beneath the normalized loss profiles determine the service times of the peak loss. This means that the service time of households with uncontrolled EV charging will become lower and for the smart EV charging variant higher.

The same method described in §8.1.4 is used to determine these new service times, but now the EV charge (load) profiles are added to the residential load profiles. This is done for each day of the year whereby the assumption has been made that the average driving distance is the same for each day. Table 8.5 shows the result of service times for the two charge variants based on the defined parameters in table 8.4.

Table 8.2: Service times of future load profiles with large penetrations of EV in hours/year

Source	Service time of load T_b	Service time of losses T_v
Residential load profiles (EnergieNed):	4300	**2350**
incl. normal growth & EV (uncontrolled charging):	3480	**1700**
incl. normal growth & EV (smart charging):	5790	**3960**

The service times change as expected from the conclusions of figure 8.5, but the difference in service time T_v between the uncontrolled and smart variant has become more than a factor 2. However, the total load losses are a product of peak loss and service time T_v. Because the peak losses are dependent on the type of asset, an example with the different losses in a MV/LV transformer will be presented to show the effect of changing load profiles on the total energy:

Example: losses in a MV/LV transformers

200 households are connected to a 400kVA MV/LV transformer. The peak load for different scenarios of this transformer can be calculated with the use of the aggregated load profiles of figure 8.4. This peak load result in a maximum loading percentage (regarding the nominal capacity). The square of the loading percentage is used to calculate the peak copper loss (see formula 8.7).

Service times of copper (load) losses:

a.) Normal households	2350 hours/year
b.) Households, 75% EV (uncontrolled)	1700 hours/year
c.) Households, 75% EV (smart charging)	3960 hours/year

Service times of iron (no-load) losses:

a.) Normal households	8760 hours/year
b.) Households, 75% EV (uncontrolled)	8760 hours/year
c.) Households, 75% EV (smart charging)	8760 hours/year

MV/LV transformer:

Nominal power:	400 kVA
Nominal iron losses:	0,515 kW
Nominal copper losses:	3,750 kW

$$E_{loss} = P_{iron} \cdot T_i + P_{copper} \cdot \alpha^2 \cdot T_v$$

Example with 400kVA MV/LV transformer	Power	Loading Percentage	Iron Losses Energy	Copper Losses Energy	Total Losses
	[kVA]	[%]	[kWh/year]	[kWh/year]	[kWh/year]
a.) 200 Households + growth	213	53%	4510	2510	**7020**
b.) 200 Households + growth + EV (uncontrolled)	372	93%	4510	5540	**10050**
c.) 200 Households + growth + EV (smart)	224	56%	4510	4650	**9160**

Fig 8.6: Example of calculating the energy losses of a transformer

The total losses in the transformer are the summation of iron and copper losses. The example shows that the copper losses (and eventually the total losses) of the uncontrolled scenario is higher than for the smart scenario, even when there is such a large difference between their service times T_v.

This is caused by the fact that the total energy in the uncontrolled charging variant is delivered with a higher peak load. The resulting peak loss is quadratic dependent on the peak load, so this means that the scenario with the highest peak load results in the most energy losses. This is true under the preconditions that total delivered energy is the same in both cases.

However, in practice, the energy losses may be higher in the smart charging scenario, because less capacity is needed and therefore the network may be reinforced with assets with smaller capacities. For example, if the transformer in the above case would be a 250 kVA instead of a 400 kVA transformer, then the 250 kVA is capable of handling the total peak load (224 kVA) in the year 2040 for the smart scenario. In the uncontrolled scenario the peak load becomes so high (372 kVA) that the 250 kVA becomes overloaded, and needs to be replaced by a bigger transformer, let's say the 400 kVA transformer. The total energy losses for the uncontrolled scenario are the same as in the original example (10050 kWh/year), but when calculating the total losses for the 250 kVA transformer in the smart scenario (using different nominal peak and copper losses, see table 8.1), this results in a higher value for the energy losses: 11570 kWh/year. An additional investment for the new transformer is of course needed in the uncontrolled scenario, but because the energy losses (yearly costs for a DSO) are lower it might be possible that the total costs (losses+investment costs transformer) are less. These kinds of elements are interesting and important for investment analysis.

Higher losses in a scenario with lower peak loads (with the same energy content) is only possible in situations where the configuration of the transformer/cable changes, but even then the losses in smart scenarios can be less.

8.3 Energy losses in future scenarios

The energy loss estimation method described in §8.1 and §8.2 can be extended to future scenarios as defined in [4]. The new technologies (heat pumps, micro-CHP, photovoltaic panels) present in these scenarios should be added to the method in the same way as done with the EVs in §8.2. Yearly load profiles are created for these new technologies. For EVs it is a good assumption to use the same daily load profile for each day of the year, because the daily driven distance at the residential level for a certain population density does not differ very much [27]. The other three technologies are however dependent on other variables (temperature, heat demand, hot water demand, solar irradiation, etc.).

The change in profiles during a year for heat pumps and micro-CHPs can be estimated with the use of thermal demand profiles over one year. Based on gas demand profiles, which are also created for the branche organization EnergieNed, the daily heat demand can be determined for house heating (which is temperature dependent) and for water heating (which is not dependent on the ambient temperature). These daily heat demands are used to scale the load profile of heat pumps during the year. The load profile of heat pumps is indirectly dependent on the demand for house and water heating [3]. Only the heat demand for house heating is used to scale the micro-CHP load profile during the year, because micro-CHPs are mostly used in bivalent configurations with an auxiliary boiler operating on gas for peak demand (e.g. hot water). The PV profile is scaled down by a solar irradiation profile, measured for one year (2010) at weather station Eelde, The Netherlands [30]. This weather station is located in the area of the set of MV networks.

Residential load profiles for a whole year including the new technologies can now be estimated for the three future scenarios. The scenario parameters (e.g. penetration degrees) in chapter 4 need to be taken into account. This new yearly load profile is used to determine the loss profile and the service times of the losses, just like in §8.1 and §8.2. Table 8.3 shows the service times for the three scenarios in the uncontrolled and controlled variant. There are some differences in new technologies between the types of residential area, however, the service times have not been calculated for each of the areas. Only a distinction has been made between existing neighborhoods and newly-built residential areas, because these differences are the largest. For example, in [4] it is assumed that there will be no micro-CHP present in newly-built areas, but instead heat pumps with additional resistive heating will be used (see chapter 4).

Table 8.3: Average service times of peak loss T_v of future scenarios in two residential areas

Scenario	Existing neighborhood [hours/year]	Newly-built residential area [hours/year]
Scenario A (uncontrolled):	1830	1460
Scenario A (controlled):	4100	3900
Scenario B (uncontrolled):	1490	1480
Scenario B (controlled):	3900	3900
Scenario C (uncontrolled):	1500	1230
Scenario C (controlled):	3900	3700

For scenario A and C there are some differences between the two residential areas. Both scenarios have a higher heat pump penetration in the newly-built residential areas, and scenario C has also more generation in these areas due to PV. The difference between the uncontrolled and controlled scenarios is as expected.

8.3.1 *Service times at different network levels*

The service times in the previous paragraphs are all valid for MV/LV transformers. However, the service times are expecting to rise at higher network levels due to the non-residential loads in the network (e.g. industry) which have more constant load profiles. Figure 8.7 shows the average load curves per network level for the uncontrolled scenario A (resulting from Visienexis). The load curves are the average load curves of all components present in the specific network level, for all MV networks. The figure shows that higher in the network the load curves become more flat. Taking the square of the normalized load curves/profiles results in normalized loss profiles per network level.

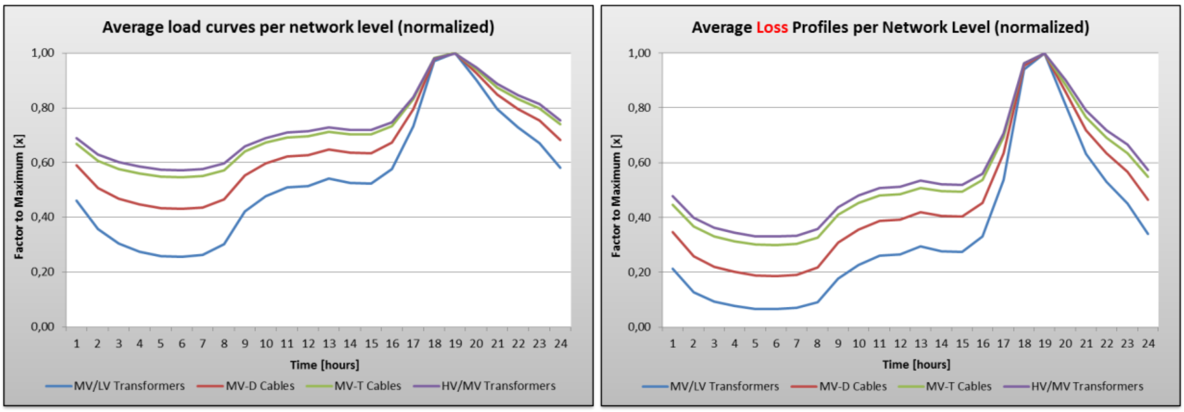


Fig 8.7: Average load and loss profiles (normalized) of scenario A uncontrolled

The ratio between service times per network level can be determined with these profiles. The estimated service times at the MV/LV transformers (in table 8.3) can in this way be scaled up for the other components. The result is presented in table 8.4. In this method the assumption has been made that the ratio between the service times per network level is more or less the same all over the year, in practice this can perhaps vary per day. The service time at the MV/LV transformers is combined to one value by the distribution ratio between the existing neighborhoods and new residential areas.

Table 8.4 shows that the highest service times arise at the MV-transmission cables instead of the HV/MV stations. One reason is that the high normal growth in scenario B and C of respectively 2% and 1% per year causes a large rise in industrial load. The industrial load, mostly connected to MV-T networks, has become predominant present in MV-T cables and causes a flatter load curves (and thus higher service times). This in combination with the fact that HV/MV stations are connected to a mix of transmission and distribution cables, it eventually results in higher service times at MV-T level.

Table 8.4: Average service times T_v of future scenarios per network level

Scenario: / Network level:	MV/LV transformers [hours/year]	MV-D cables [hours/year]	MV-T cables [hours/year]	HV/MV stations [hours/year]
Scenario A (uncontrolled):	1700	2430	2900	2900
Scenario A (controlled):	4000	4280	4590	4650
Scenario B (uncontrolled):	1490	2110	2370	2180
Scenario B (controlled):	3900	4190	4240	4180
Scenario C (uncontrolled):	1400	2070	2440	2270
Scenario C (controlled):	3800	4090	4230	4200

8.3.2 Total losses per scenario

At first sight it seems to be possible to calculate the total energy losses of the future scenarios. The peak loss of the components can be retrieved from the load-flow output or can be calculated with the loading percentage, and the service times of the losses are estimated. All parameters for the calculation of the total losses are known. However, the load-flow calculations done in this study have been used to calculate the loadings in 2040, but the assets in the networks have not been reinforced. Therefore, the peak losses calculated in the load-flow do not match the actual peak losses of the assets in 2040. In order to calculate the correct peak losses and energy losses in 2040, the network configuration with the new components in 2040 needs to be known or estimated. This is however very dependent on the replacement strategy and defined overload criteria. After that, a new load-flow could be carried out including the new installed components and (extended) network structure to determine the peak losses.

This step is more essential for investment analysis with different replacement strategies. This part is outside the scope of this research. The estimation of the service times estimated here can be very useful for the investment analysis.

8.4 Conclusions

No-load losses are relative easy to determine, but load dependent losses are difficult to determine because the load variation over a year needs to be known. When adding yearly future load profiles of new technologies to yearly residential load profiles, it is possible to estimate the changing service times of the energy (load) losses by the techniques/methods described in §8.1 and §8.2. The service times for uncontrolled scenarios will be less than nowadays and for controlled scenarios they will be higher. A factor 2 difference in service time can be the case between the uncontrolled and controlled scenarios.

The total energy losses are however a product of peak loss and service time of the peak loss. The total losses are always lower in the controlled scenario under the preconditions that the energy content is the same and the load is subjected to the same component in both cases. This is caused by the fact that the energy in the uncontrolled scenarios is delivered with a higher peak load. The resulting peak loss is quadratic dependent on the peak load, so this means that the scenario with the highest peak load results in the highest energy losses. Higher losses in a scenario with lower peak loads (with the same energy content) is possible in situations where the capacities of the transformers/cables are different, but even then the losses in smart scenarios can be less.

The energy losses for the three future scenarios cannot be calculated with the results from the load-flow calculations. The peak losses of the components are incorrect and unrealistic because many components are overloaded and not replaced. These components would already be replaced or extended before the year 2040. In order to calculate the correct peak losses and energy losses in 2040, the network configuration in 2040 needs to be estimated, but this is very dependent on the replacement strategy and overload criteria. This part is outside the scope of the research, but will be necessary for investment analysis.

9 Conclusions & Recommendations

9.1 Conclusions

The impact of future residential loads on the MV network for three different future scenarios (2040) have been analysed and identified. The results from the executed load-flow calculations applied to 50 MV networks of DSO Enexis show large differences in component loadings between the scenarios. All three scenarios do show large impacts on the MV-Transmission level and the HV/MV stations. Large reinforcements will be necessary at these network levels, which are most costly.

Scenario B causes the largest impact on component loadings, which is the result of a high demand: high penetrations of electrical vehicles and heat pumps, and a substantial rise in 'normal' demand (2% per year). Scenario A has a relative low impact (small demand growth) and results of Scenario C are in between (also caused by high penetrations of EVs and heat pumps, but in this scenario the rise in 'normal' demand is smaller).

Scenario B and C show large differences compared to the 1% growth scenario, the conventional network planning method. If this conventional method would still be applied, a large error in the expecting overloads may resolve in an inefficient replacement strategy.

Most notable is the fact that in all scenarios the percentages of overloaded components have significantly been reduced by applying control to residential loads and generators. Especially in scenarios where the dominance of the 'normal growth factor' is relatively low (e.g. scenario A).

All future scenarios have been modelled with the constant impedance load model instead of the conventional constant power load model. Constant power load models are highly questionable in distribution systems, as most nodes are not voltage controlled (like in HV networks) and the loads in MV networks behave rarely pure as constant power. This representation may also cause convergence problems in load-flow calculations. These effects are also noticed in the case study. About 50% of the networks have convergence problems for scenario B. The combination of high demand, overloaded components and constant power load behaviour result to this problem. Analysis show that most deviations in component loadings (between the two behaviours) stays within tolerances of ±10%.

The energy losses and node voltages for the three future scenarios cannot be calculated with the results from the load-flow calculations. The peak losses of the components are incorrect and unrealistic because many components are overloaded and not replaced. The same accounts for node voltages: the substantial amount of overloaded components result in additional voltage drops and unrealistic node voltages. The overloaded components would already be replaced or extended before the year 2040. In order to calculate the correct peak losses and node voltages in 2040, the network configuration in 2040 needs to be estimated.

However, the service times of the energy losses can already be estimated. When adding yearly future load profiles of new technologies to yearly residential load profiles, it is possible to estimate the changing service times of the energy (load) losses. The service times for uncontrolled scenarios will be less than nowadays and for controlled scenarios they will be higher. A factor 2 difference in service time can be the case between the uncontrolled and controlled scenarios. The total energy losses are however a product of peak loss and service time of the peak loss. The total losses are always lower in the controlled scenario under the preconditions that the energy content is the same and the load is subjected to the same component in both cases. This is caused by the fact that the energy in the uncontrolled scenarios is delivered with a higher peak load.

9.2 Recommendations and future research

The effect of applying control to residential loads and generators for scenario B is not impressive. The reason for this is the substantial rise in 'normal' demand (2% per year). The effect of this growth factor on the existing (peak) load is dominant with regard to the reduction in peak load due to smart control. The peak load will therefore rise substantial in both cases (controlled and uncontrolled). For the MV/LV-transformer level this effect has less influence, but on higher network levels where mainly large non-residential loads (e.g. industry) are connected (to which no control is applied in this study), the growth factor implies a substantial rise in peak load. So the 'normal' growth factor becomes dominant and damps out the effect of controllable residential loads and generators on the higher network levels. Because these large demand growths have such an impact, it is interesting for further research to verify if these large growth factors for non-residential loads on the existing MV networks are realistic and above all to investigate the potential of control of these non-residential loads.

The results for the component loadings are dependent on the overload criteria. Each network level has special properties which need to be taken into account for a representative overload criteria. A very important aspect in the MV-D and MV-T network is the n-1 criteria. In this study the correction factor for the n-1 criteria in the MV-D and MV-T network is assumed (with quite some uncertainty), because Visienexis is not able to identify the number of MV-T bundles in a MV-T network and cannot evaluate different NOP points in MV-D ring structures. For the case study the assumptions made are satisfactory to compare relative differences between scenarios. However, for further research where absolute values are of more importance, the n-1 correction factor need to be determined more precise. Interesting would be to check if the remaining capacity in MV-D networks is indeed this high for the set of MV networks, and the capacity in the MV-T network is this limited.

The overload criteria for all network levels in every scenario is fixed at the present criteria. The used criteria are valid for existing load profiles. The existing load profiles for the three future scenarios will change, which might result in different overload criteria. For the controlled scenarios the load becomes more continuous and the ratio between peak and base load has become smaller. Assets become less capable of handling loadings above nominal capacity, since there will be less time for cooling down. This would result in a reduced life expectancy of the asset. Therefore, the overload threshold probably needs to be corrected downwards. In case of uncontrolled load profiles in the three future scenarios there is a large variation in load, even larger than for the existing profiles. This might result in a positive correction of the overload criteria. The changing load profiles and the differences between controlled and uncontrolled profiles, will also have effect on the (service times of the) energy losses in the network. All these kinds of issues are important for further research and investment analysis.

The same holds true for the other variable composing the energy losses: the peak losses. The peak losses of the components are incorrect and unrealistic because many components are overloaded and not replaced. In order to calculate the correct peak losses and energy losses in 2040, the network configuration in 2040 needs to be estimated, but this is very dependent on the replacement strategy and again the overload criteria.

The constant impedance load model should be used for studying the component loadings in existing MV networks with future load conditions. This results in no convergence problems and the difference in loadings between the constant power model is acceptable. The constant power load model in case of scenario A and C is even less conservative for component loadings than the constant impedance model. For voltage levels this might not be the case. Just like the peak losses, the actual node voltages in 2040 can only be determined with the new (extended) network situation. If this analysis will be performed, the effect of load behaviour on the voltage may become important. For components loadings is seen that deviations of ±10% may occur, this is however unacceptable for node voltages. For a node voltage study it might be necessary to predict a more representative load behaviour. The effect of future residential loads on the load behaviour should then also be investigated. The actual load behaviour of loads in the MV network is related to the actual node voltages and component loadings. The real values will always be somewhere between the constant power and constant impedance load model.

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Appendix

A. Cable loading: Correction factors

The values in these paragraphs apply for the single-core XLPE cable.

$I_{nominaal}$
The nominal current of single core XLPE cables is dependent on the way of earthing, position configuration and possible used cross bounding.

Background Cross bounding:
Because of the use of single-core XLPE cables, every phase is provided with an earth screen. When the current is flowing through the conductor, there will also be a current flowing through the earth screen (if the screen is earthed at two sides of the cable). This is because the core
current induces a voltage in the earth screen together with a screen current. This naturally causes heat development, which results in power losses and a higher cable temperature. The cable load will be reduced by 5% because of the screen losses. The screen current can be limited by reducing the induced voltage in the earth screen. This can be reached by (table A.1 shows the effect of these techniques on nominal current):

Table A.1: Nominal current of XLPE cables

Cross section [mm^2]	Cross bounding or single earthing?	Positioning Triangle *** Al		Flat *** Al	
		Al	Cu	Al	Cu
150	Yes	290	370	315	410
240	Yes	375	490	420	540
400	Yes	485	615	520	670
630	Yes	620	775	675	850
800	Yes	700	850	765	950
150	No	285	365	300	375
240	No	370	475	385	480
400	No	475	590	455	540
630	No	605	735	560	650
800	No	675	805	610	695

- Applying cross bounding. The earth screen will then by divided by 3 (or a multiple of 3) parts and cyclic connected at 2 (or 5 or 8 etc.) locations. The resultant of the induced voltage in the earth screen will then be reduced to zero. By doing so, also the screen currents are reduced to zero.
- Earthing of the earth screen at a single side of the cable.

Enexis applies cross bounding only at MV-T networks and at a cable length bigger than 750m. From this length are the costs of cross bounding joints lower than the costs of power losses.

P (correction factor for parallel circuits and deviating thermal resistance)

Tabel A.2: Correction factors for parallel circuits and deviating thermal resistance

Thermal resistance of the ground	Inter-space	Number of parallel cables operational: Single-core (triangle)						Single-core (flat)		
[Km/W]	[mm]	1	2	3	4	5	6	1	2	3
Peat:	-	0,81	-	-	-	-	-	0,81	-	-
	70	-	0,63	0,54	0,46	0,40	0,35	-	0,64	0,57
2,0	250	-	0,67	0,60	0,54	0,59	0,45	-	-	-
Other raw	-	1,00	-	-	-	-	-	1,00	-	-
materials:	70	-	0,78	0,68	0,59	0,52	0,47	-	0,80	0,71
0,75	250	-	0,84	0,74	0,67	0,62	0,58	-	-	-

The correction factor P has a thermal background and is dependent on:

- The number of parallel cables
- The distance between the parallel cables
- The thermal resistance of the ground

T (correction factor for deviating ground temperature)
The factor T is defined by the ground temperature at the position depth of the cable (average 90cm). This temperature in general looks like the graph in figure A.1

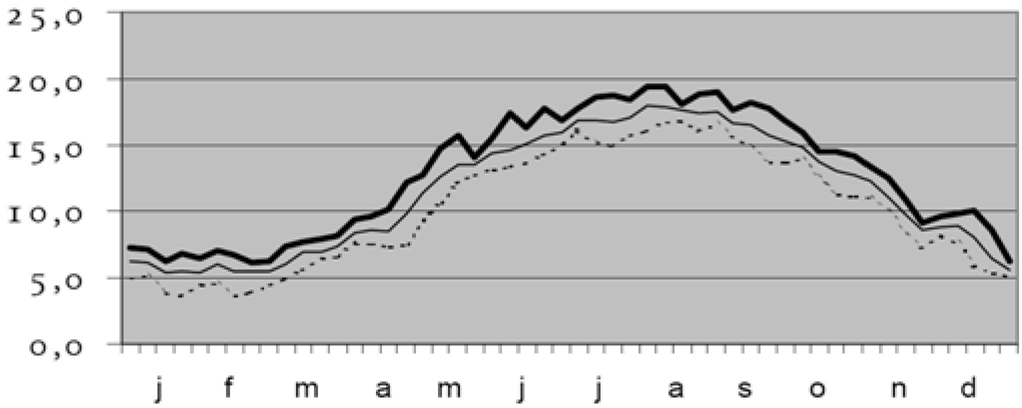


Fig A.1: Ground temperatures in °C per month (min, average, max)

The maximum ground temperature per season is based on this graph. This ground temperature is decisive for the correction factor and is shown in table A.3.

Tabel A.3: Correction factors for deviating ground temperature

Period of the year	Maximum ground temperature	Correction factor XLPE
dec, jan, feb, mrt	10°C	1,07
jul, aug, sep	20°C	0,92

D (correction factor for changing load pattern)
The values of nominal cable loads in above tables are only applicable for continuous loading of the cables. In reality, the load is almost never continuous, but changes over day. This means that with a changing day load, it is allowed to have a higher load for a certain time then the above values. This only counts if the cable gets enough time to cool down again.

Tabel A.4: Correction factors for changing load pattern

Load Type	Number of parallel cables		
	1	2	≥3
Domestic	1,50	1,40	1,30
Industrial or mixed	1,45	1,30	1,25
Individual custumer	1,10	1,10	1,10
Individual custumer with DG	1,00	1,00	1,00

V (correction factor for unequal loaded parallel cables)
In $I_{max\_equal\_loaded}$ the correction factor P is taken into consideration for equally loaded parallel cables. However, in practice the parallel cables can have an unequal loaded pattern. In these cased one cable reaches its limit sooner than the other. At that moment the heat development of all cables is lower than when the cables reach their limits simultaneously. De V factor is used to discount this difference.

It is allowed [12] to multiply the real cable load with the factor V in order to determine the load values whereat the heat development of unequal loaded cables is equal to the maximum allowed heat development of the same cables but then with an equal load. This can be translated to the following formula:

$$I_{max\_unequal\_loaded} = I_{load} \cdot V$$

De correction factor V is defined as de root of the ratio between the heat development of equal loaded cables and the real heat development of unequal loaded cables. With the assumption that the heat development is proportional with the square of the current, it results in the following formula:

$$V = \sqrt{\frac{\sum I^2_{max\_equal\_loaded}}{\sum I^2_{load}}}$$

In this approximation not the heat development of the individual, but the heat development of all the cables is considered.

B. Load profiles at transformers

The load parameters of the individual distribution transformers are not available, but known is that the load profile of a certain customer group have a high degree of uniformity. At this moment standard load profiles for specific customers groups are used at Enexis. These groups are defined:

a.) Residential
b.) Mixed (partly residential, partly industrial)
c.) Industrial

Load profiles of (business) customers with an own transformer are more difficult to create. This also counts for transformers that are used for CHP and wind turbines. The load patterns can be extracted from load measurements, but mostly the 'worst case' assumption is made for this group (constant load of 100%, during 24 hours a day, 7 days per week).

If the relation between the maximum and minimum load during one cycle is known and also the time how long the maximum load occurs, it is possible to determine the loading factor of the transformer without exceeding an aging rate higher than 1 [14].

The IEC norm [14] used simplified load profiles like figure B.1 to determine this factor.

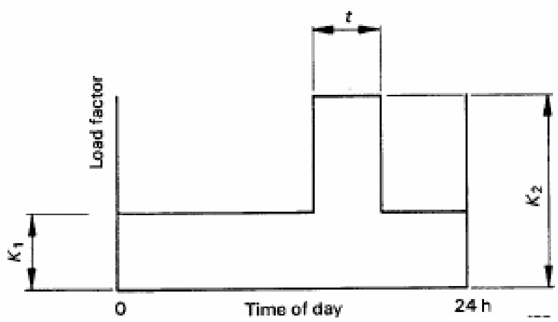


Fig B.1: Simplified daily load profile

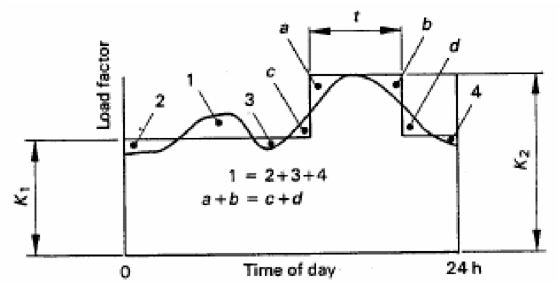


Fig B.2: Simplified daily load profile

The parameters K_1, K_2 en t are defined dependent on the real daily load profile, see figure B.2. The areas 'above' and 'under' the simplified load profile should be equal ($1 = 2 + 3 + 4$ and $a + b = c + d$). The following parameters are defined as follows:

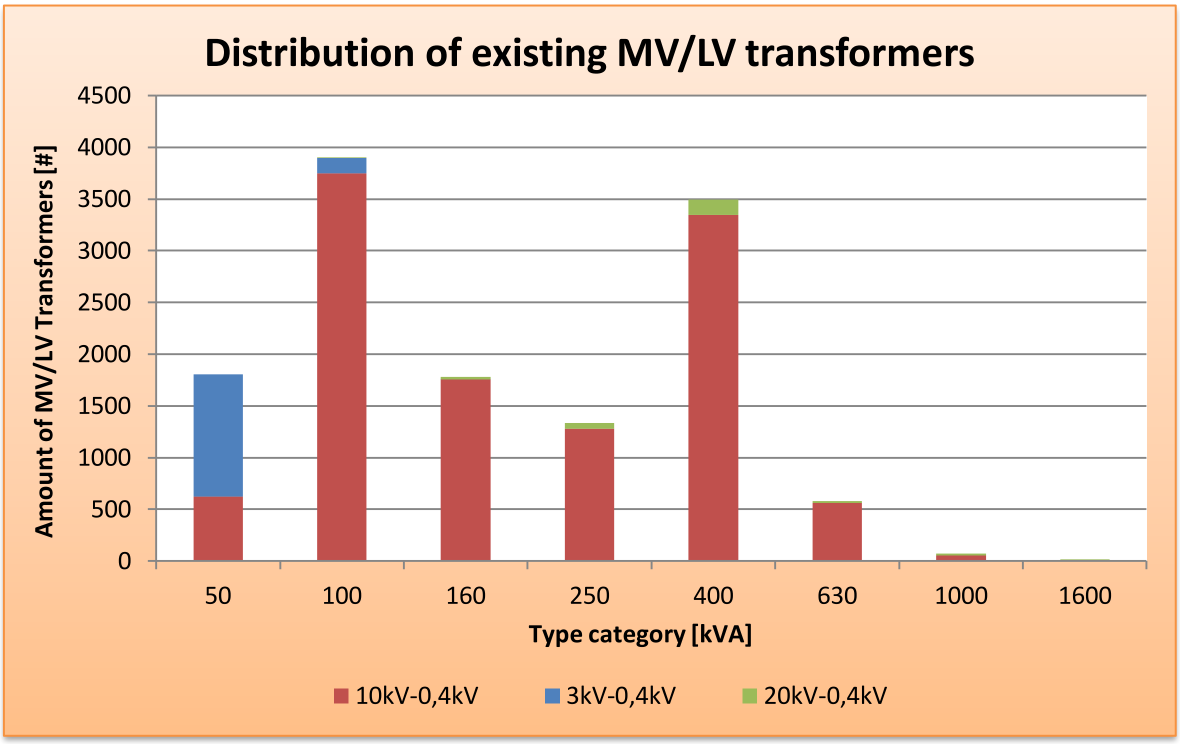
- Load factor $\mathbf{K_1}$ = $I_1 / I_{nominal}$ [p.u.]
- Overload factor $\mathbf{K_2}$ = $I_2 / I_{nominal}$ [p.u.]
- Duration of time **t** [hours] for the appearance of the maximum load (factor) K_2

(I_1 = lower load, I_2 = maximum load)

The different occurring load profiles of the specific customer groups are translated to representative values for K_1, the relation K_2/K_1 and t (see table 2.2).

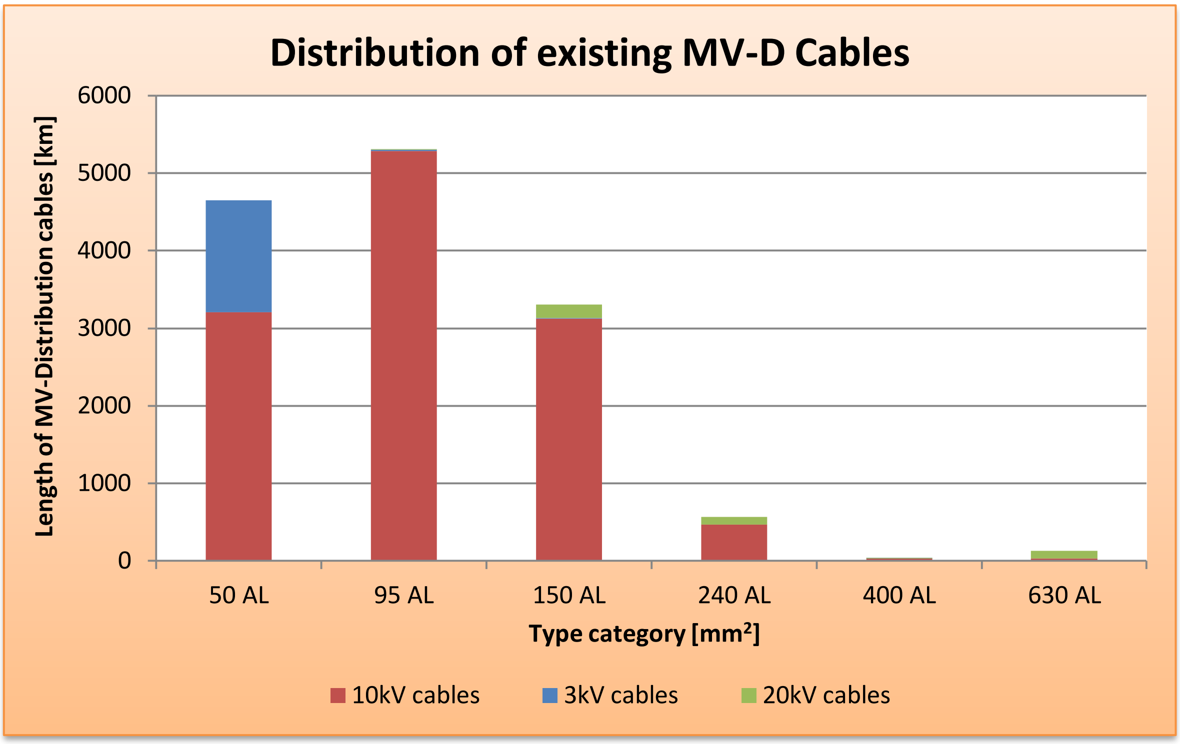
C. Dataset: Distribution of Assets

C.1 MV/LV Transformers



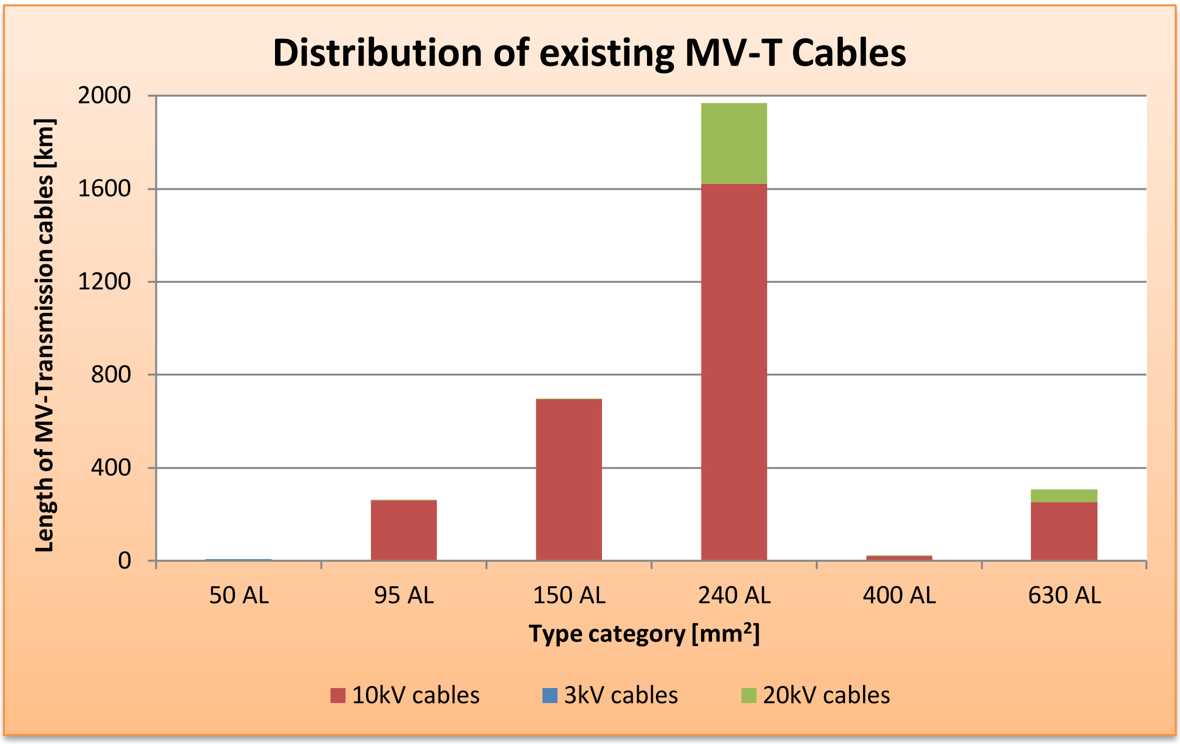
Distribution of existing MV/LV Transformers					
Snom [kVA]	Total [#]	Unom 3kV	Unom 10kV	Unom 20kV	Range [kVA]
50	1807	*1185*	*622*	*0*	x <= 70
100	3905	150	3746	9	x <= 125
160	1781	1	1753	27	x <= 200
250	1336	0	1279	57	x <= 300
400	3494	0	3346	148	x <= 500
630	582	0	563	19	x <= 800
1000	70	0	54	16	x <= 1250
1600	11	0	10	1	x => 1500
Total:	12986	1336	11373	277	

C.2 MV-Distribution cables



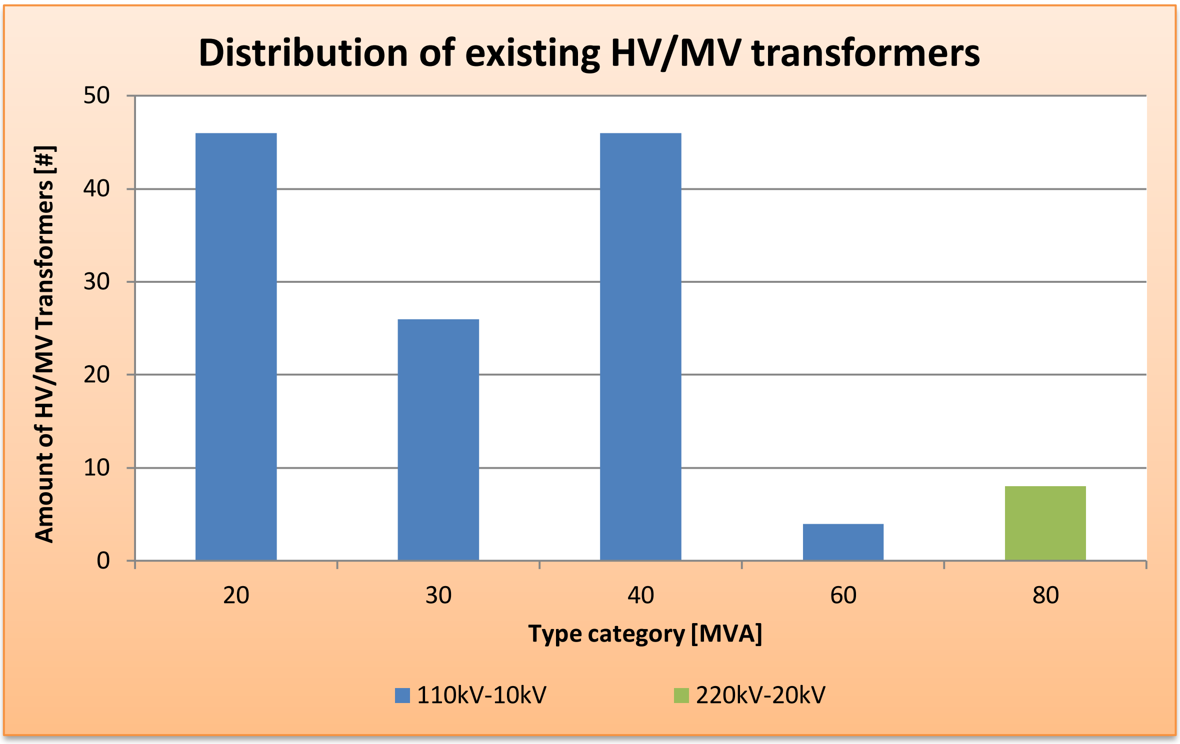
Distribution of existing MV-D Cables					
Type AL / CU	Total	Unom 3kV	Unom 10kV	Unom 20kV	Range
[mm2]	[m]	[m]	[m]	[m]	[mm2]
50 AL	4655081	1448379	3206702	0	x <= 50 AL & 35 CU
95 AL	5313132	15229	5290905	6998	x <= 95 AL & 70 CU
150 AL	3306076	790	3128804	176482	x <= 185 AL & 120 CU
240 AL	568295	0	464168	104127	x <= 240 AL & 185 CU
400 AL	34267	6	34256	5	x <= 400 AL & 240 CU
630 AL	129447	0	32297	97150	x <= 630 AL & 630 CU
Total:	14006298	1464404	12157132	384762	

C.3 MV-Transmission cables



Distribution of existing MV-T Cables					
Type AL / CU	Total	Unom 3kV	Unom 10kV	Unom 20kV	Range
[mm2]	[m]	[m]	[m]	[m]	[mm2]
50 AL	6714	640	6074	0	x <= 50 AL & 35 CU
95 AL	261740	0	261739	1	x <= 95 AL & 70 CU
150 AL	697409	0	695806	1603	x <= 185 AL & 120 CU
240 AL	1967595	0	1621111	346484	x <= 240 AL & 185 CU
400 AL	20642	0	20640	2	x <= 400 AL & 240 CU
630 AL	307645	0	253612	54033	x <= 630 AL & 630 CU
Total:	3261745	640	2858982	402123	

C.4 HV/MV Transformers



Distribution of existing HV/MV transformers				
Snom [MVA]	Totaal [x]	110/10 [x]	220/20 [x]	Range [MVA]
20	46	46	0	x <= 25
30	26	26	0	x <= 34
40	46	46	0	x <= 48
60	4	4	0	x <= 65
80	8	0	8	x <= 80
Total:	130			

C.5 Raw data

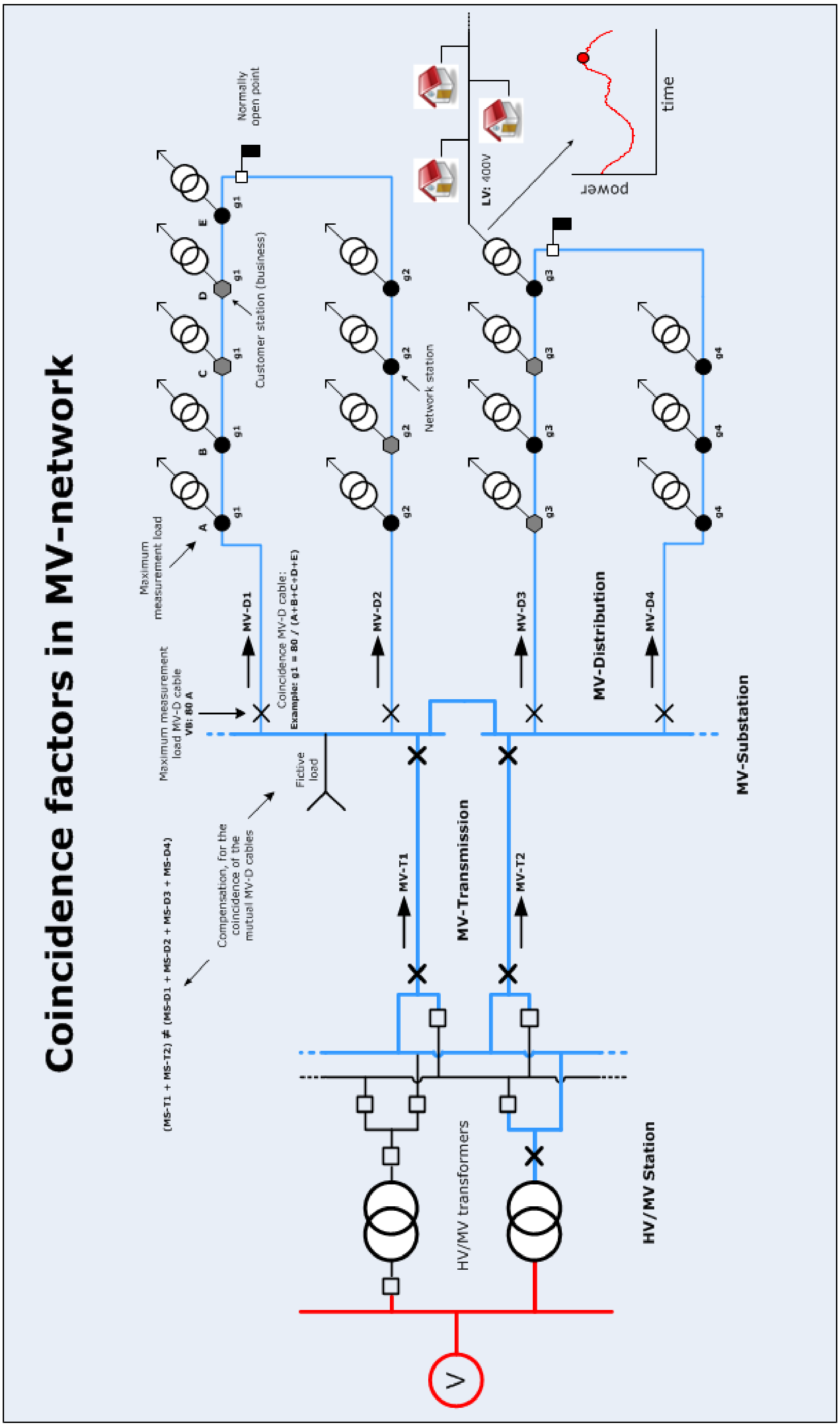
MV/LV Transformers			
Snom [kVA]	Unom 3kV	Unom 10kV	Unom 20kV
10	6	0	0
15	13	1	0
20	22	4	0
21	56	0	0
30	51	13	0
40	521	2	0
50	400	598	0
60	116	2	0
70	0	2	0
75	0	135	0
80	0	139	0
100	150	3463	9
125	0	9	0
150	0	191	0
160	1	875	27
200	0	687	0
250	0	1150	57
300	0	129	0
315	0	798	0
400	0	2544	148
500	0	4	0
600	0	17	0
630	0	539	19
800	0	7	0
1000	0	54	16
1250	0	0	0
1500	0	3	0
1600	0	7	1
2000	0	0	0
2500	0	0	0

MV-D Cables			
Type AL / CU [mm2]	Unom 3kV [m]	Unom 10kV [m]	Unom 20kV [m]
10 CU	1133263	173960	0
16 CU	212930	831430	0
25 CU	9049	234590	0
35 CU	912	713771	0
50 CU	3694	980366	0
70 CU	0	602749	0
95 CU	0	526638	0
120 CU	0	372756	0
150 CU	0	95784	0
185 CU	0	19504	0
240 CU	6	13639	5
300 CU	0	40	0
400 CU	0	28	0
630 CU	0	2	0
16 AL	154	5048	0
25 AL	19429	461866	0
35 AL	0	5836	0
50 AL	72642	780201	0
70 AL	1327	1084254	6998
95 AL	10208	2623536	0
120 AL	0	802011	101759
150 AL	790	1427399	74723
185 AL	0	0	0
200 AL	0	0	0
240 AL	0	348880	104127
400 AL	0	20617	0
630 AL	0	32227	97150

MV-T Cables			
Type AL / CU [mm2]	Unom 3kV [m]	Unom 10kV [m]	Unom 20kV [m]
10 CU	250	46	0
16 CU	158	29	0
25 CU	232	0	0
35 CU	0	1571	0
50 CU	0	31600	0
70 CU	0	150145	0
95 CU	0	148308	0
120 CU	0	314328	0
150 CU	0	124924	0
185 CU	0	65693	0
240 CU	0	16223	2
300 CU	0	66	0
400 CU	0	5230	0
630 CU	0	2	0
16 AL	0	0	0
25 AL	0	3412	0
35 AL	0	0	0
50 AL	0	1016	0
70 AL	0	556	0
95 AL	0	79438	1
120 AL	0	63042	0
150 AL	0	170128	1603
185 AL	0	0	0
200 AL	0	0	0
240 AL	0	1430494	346484
400 AL	0	4417	0
630 AL	0	248314	54033

HV/MV Transformers			
Snom [MVA]	Total [x]	110/10 [x]	220/20 [x]
15	1	1	0
18	4	4	0
20	28	28	0
24	11	11	0
25	2	2	0
26	7	7	0
30	18	18	0
34	1	1	0
40	39	39	0
44	7	7	0
60	3	3	0
65	1	1	0
80	8	0	8

D. Coincidence factor in MV networks



E. Overview of the results per scenario

E.1 Overview results scenario A (uncontrolled)

E.2 Overview results scenario B (uncontrolled)

E.3 Overview results scenario C (uncontrolled)

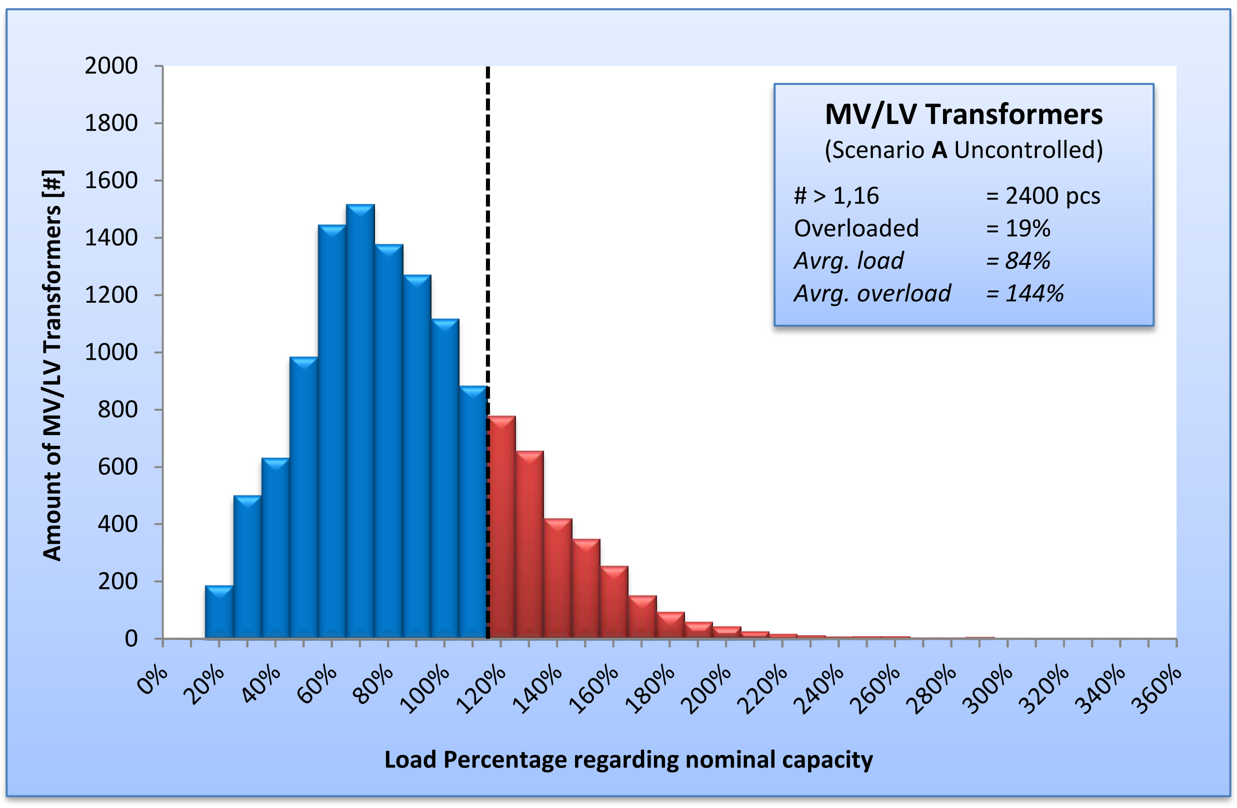
E.4 Overview results scenario 'normal growth'

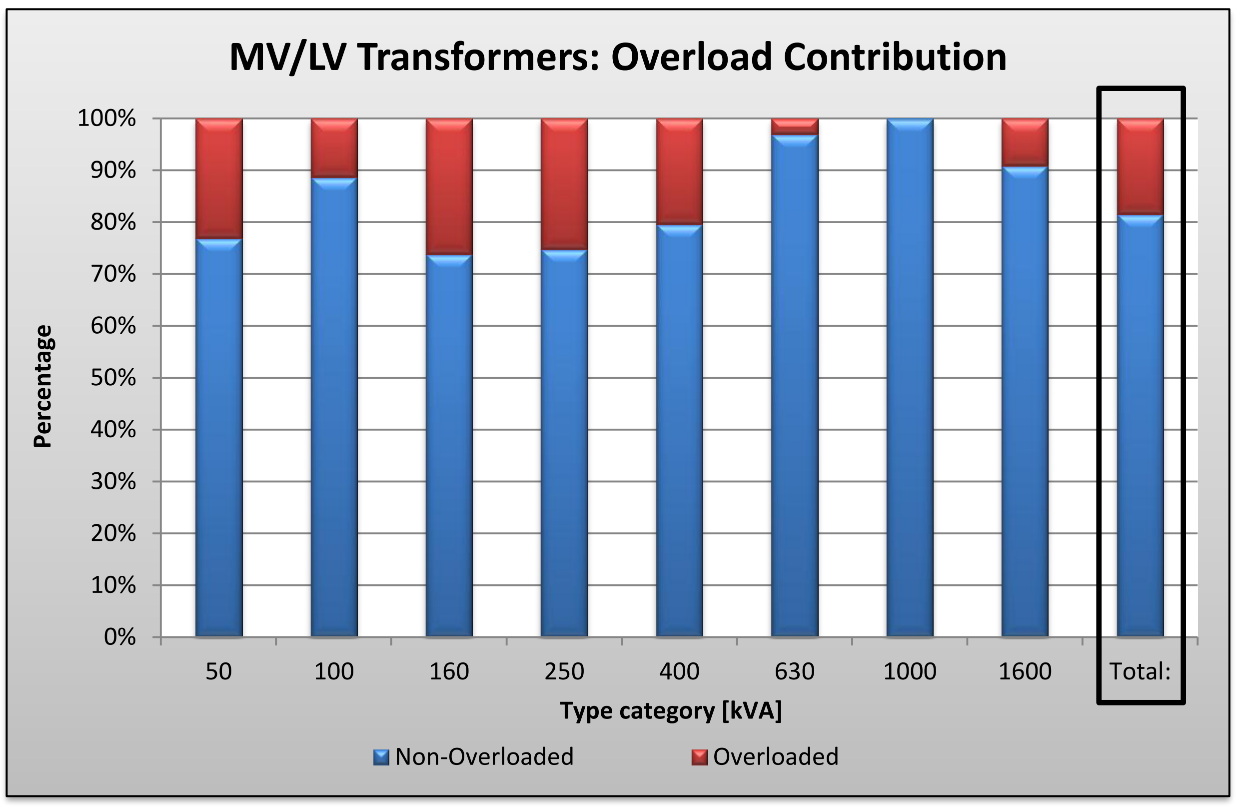
E.5 Overview results scenario A (controlled)

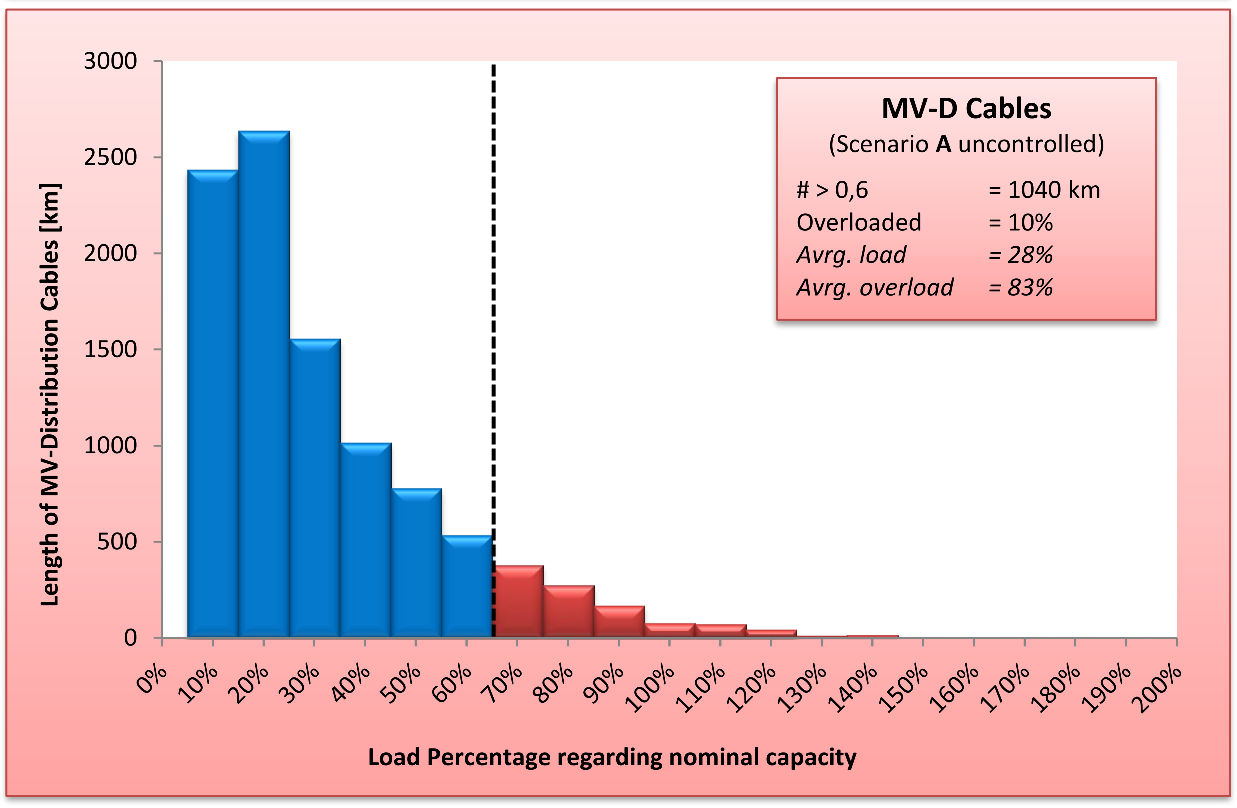
E.6 Overview results scenario B (controlled)

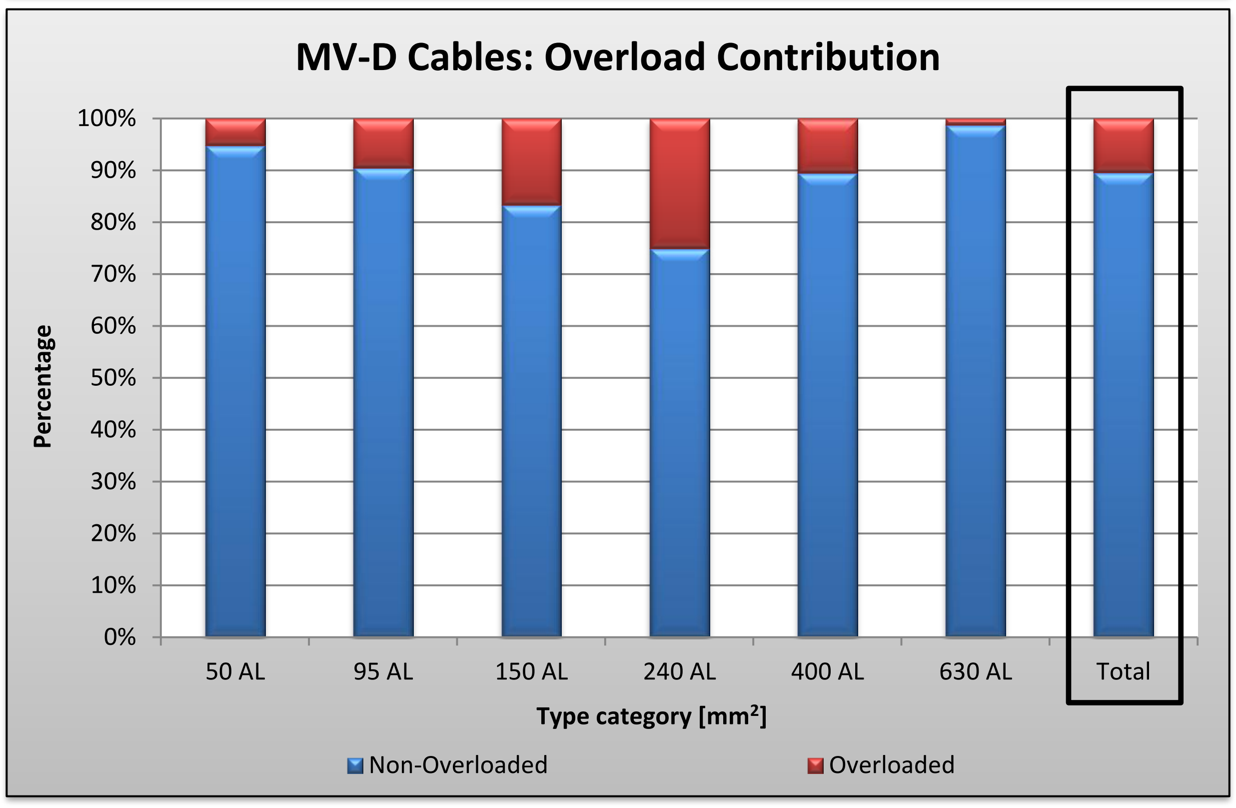
E.7 Overview results scenario C (controlled)

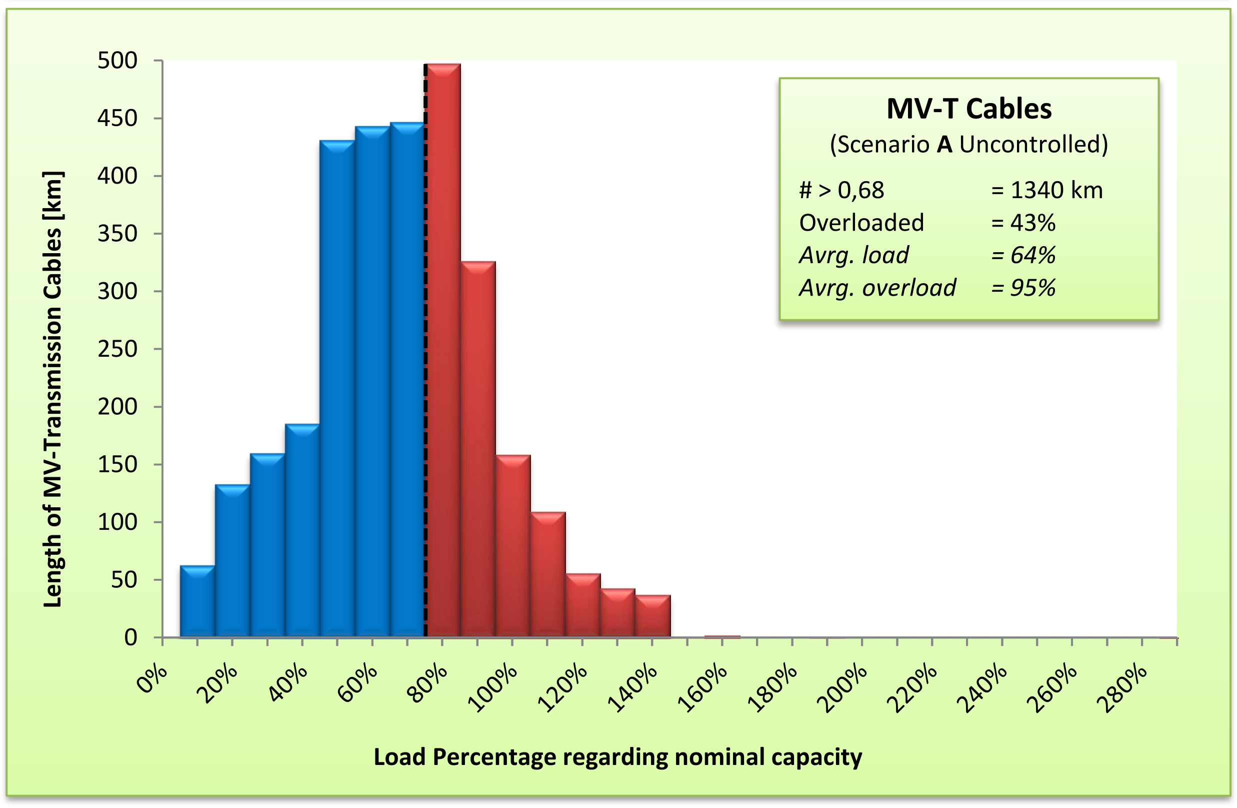
Overview Results Scenario A Uncontrolled

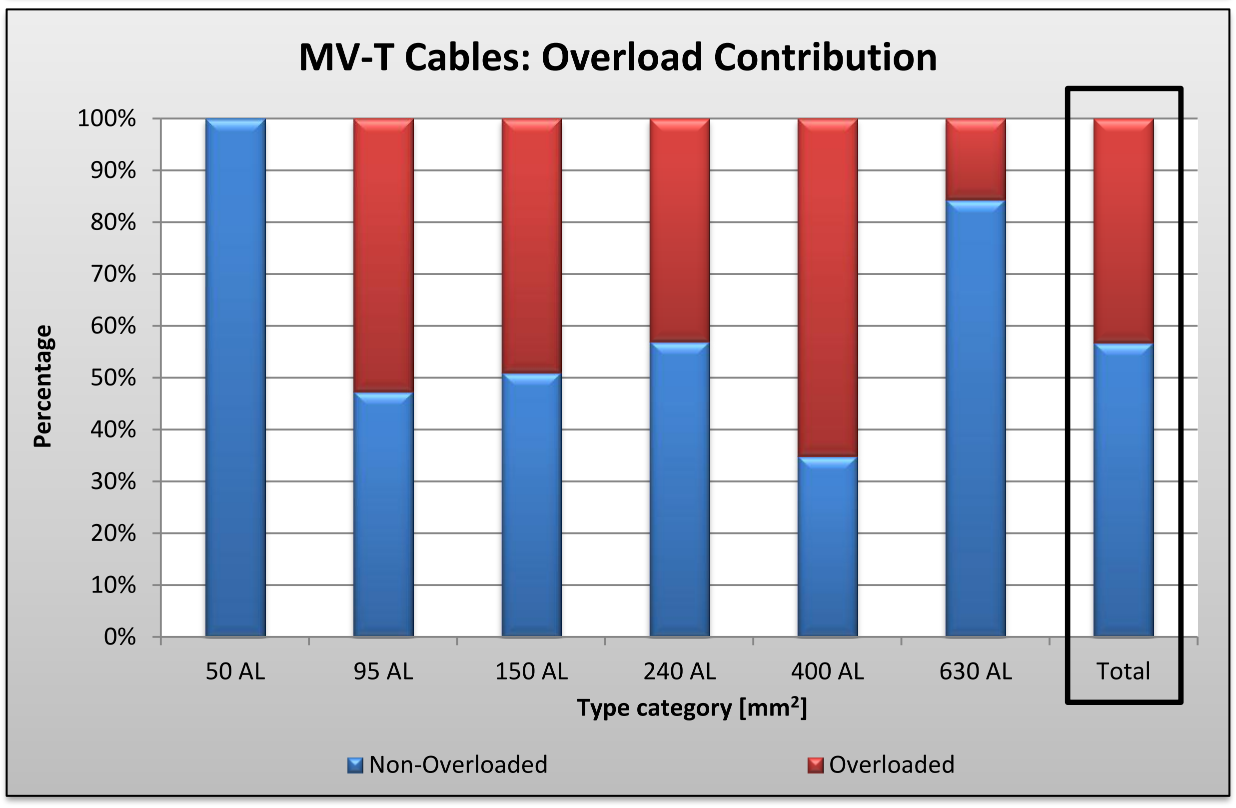


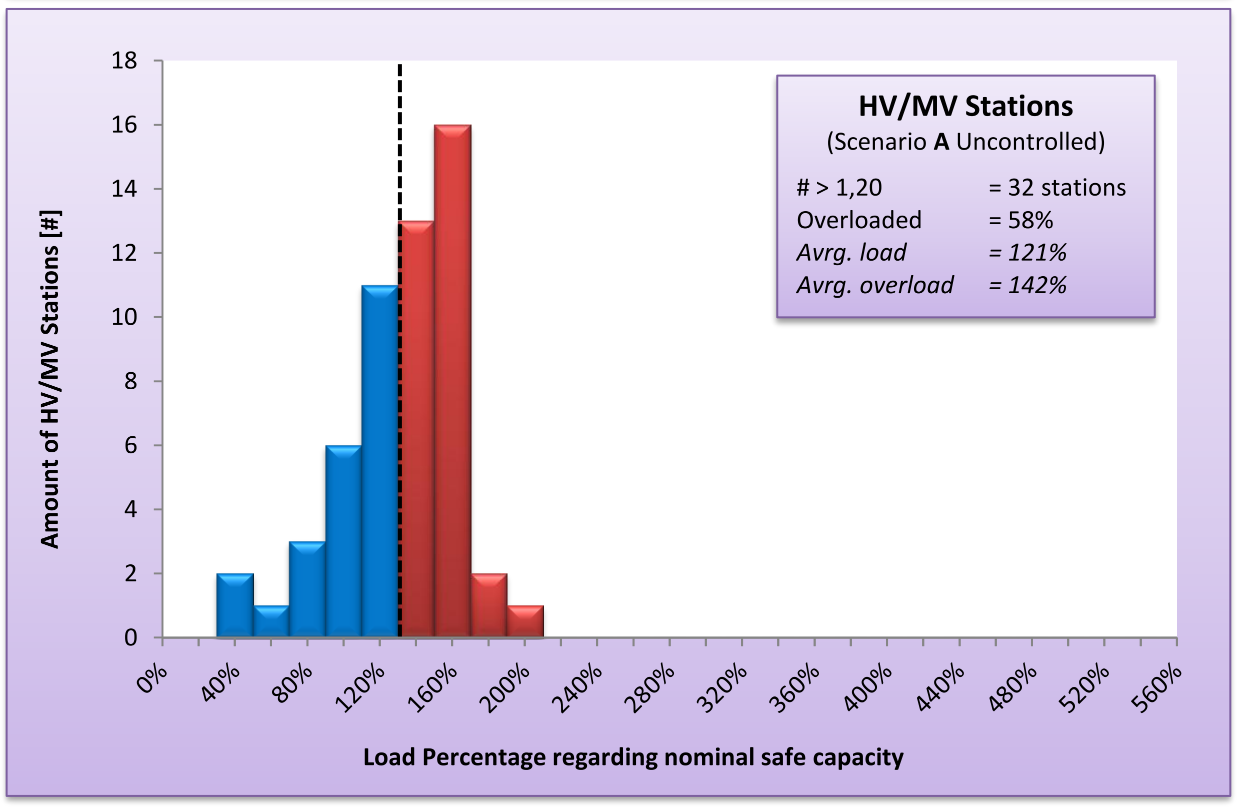


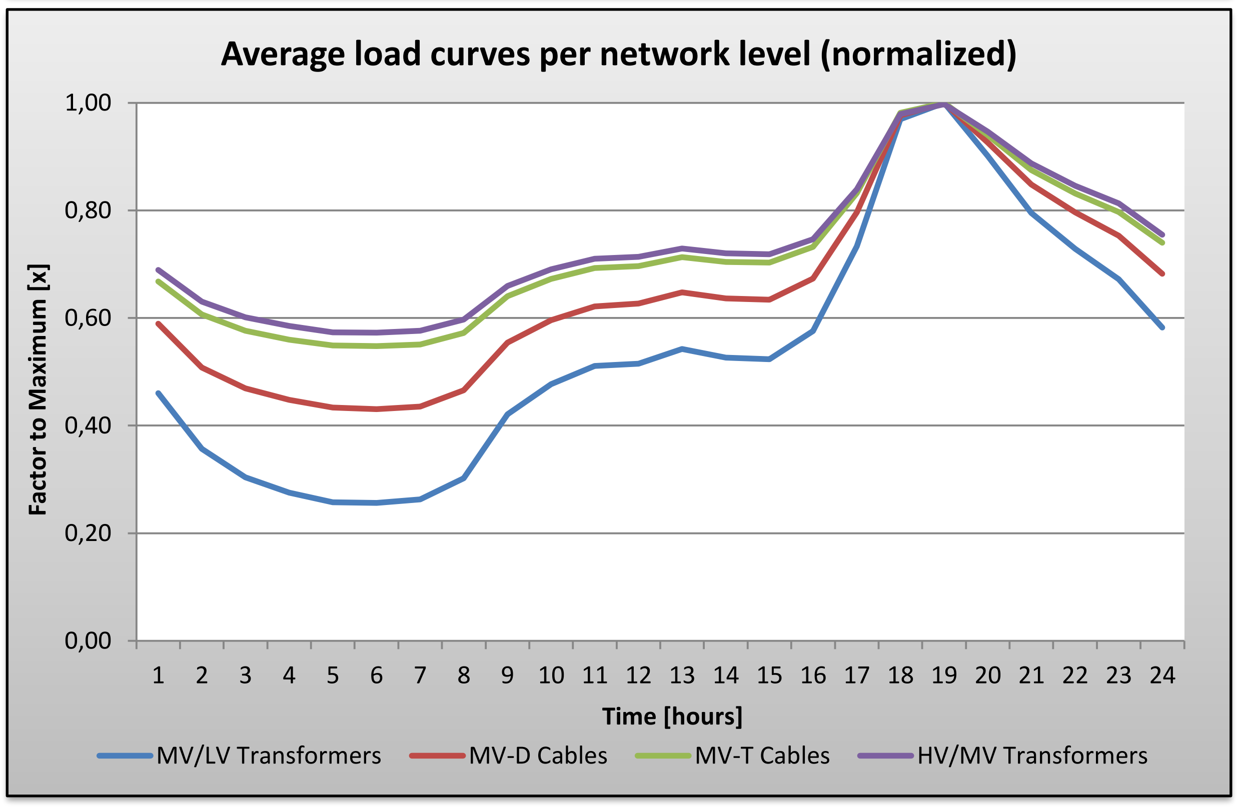




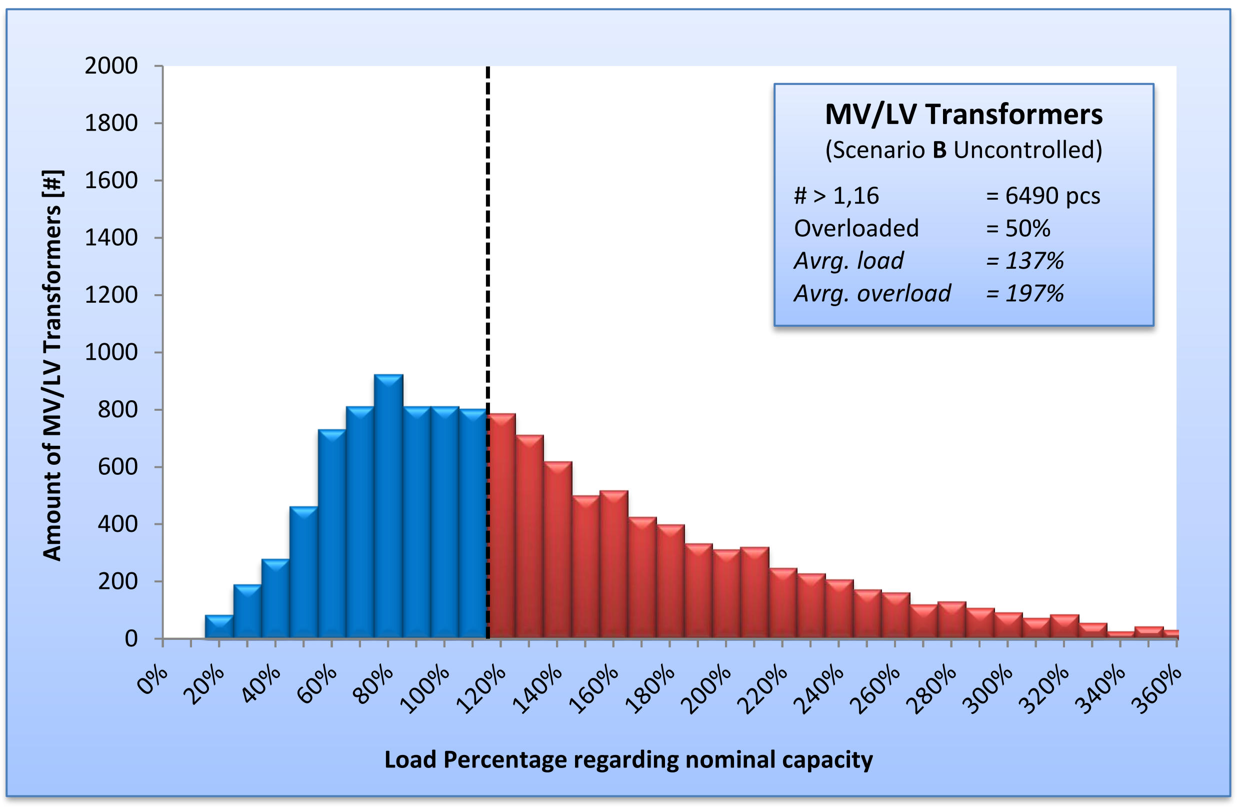


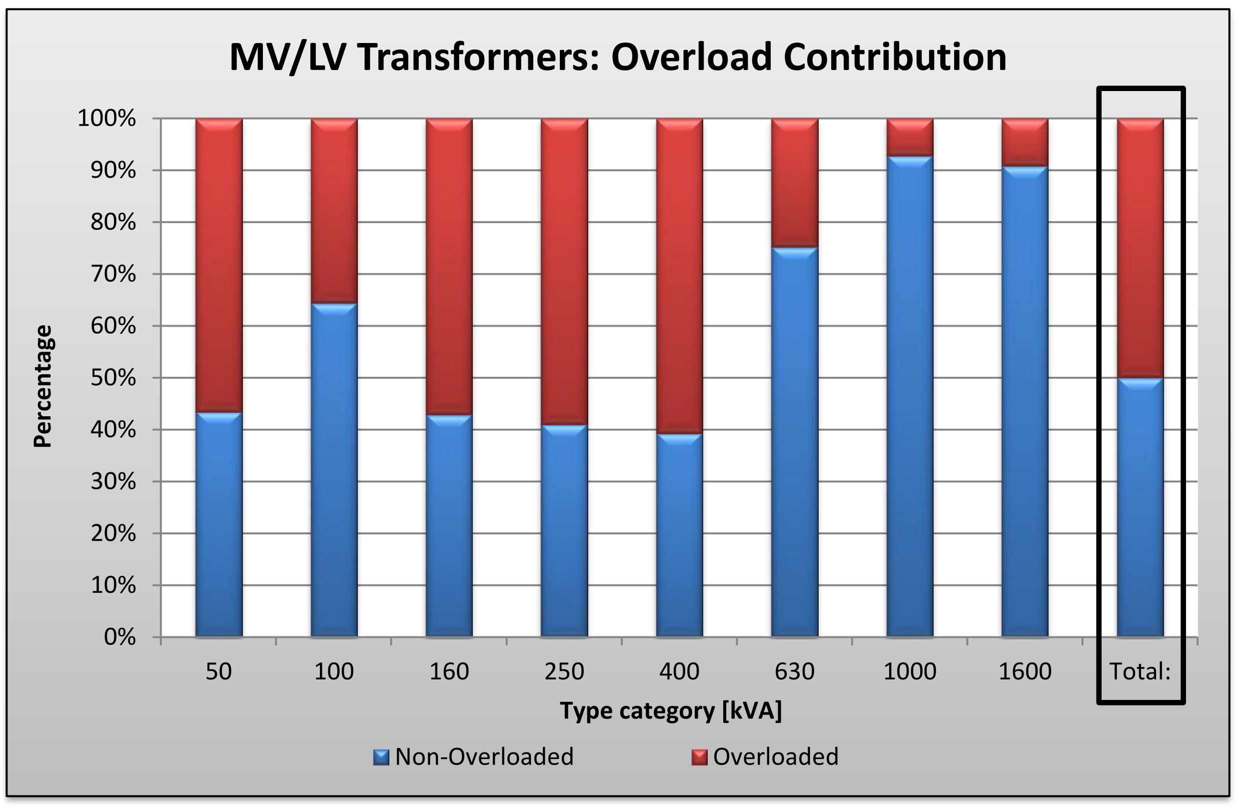


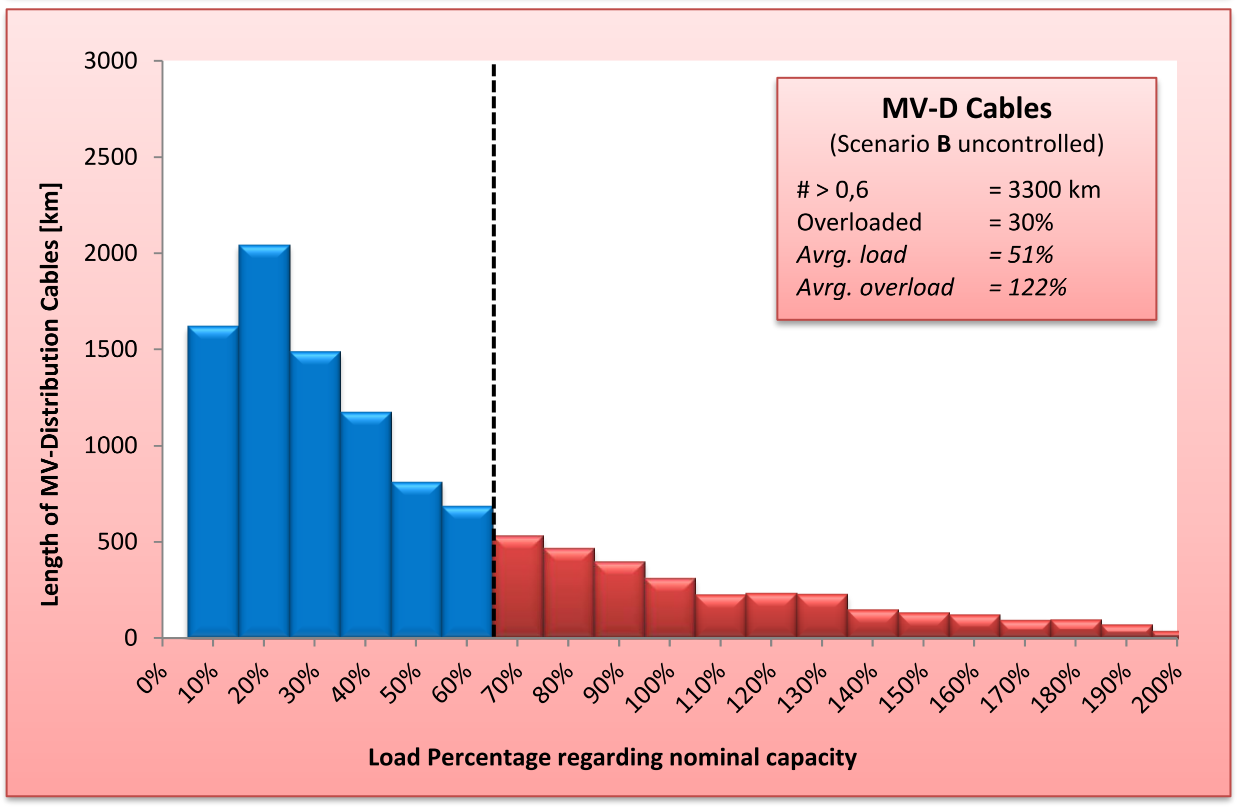


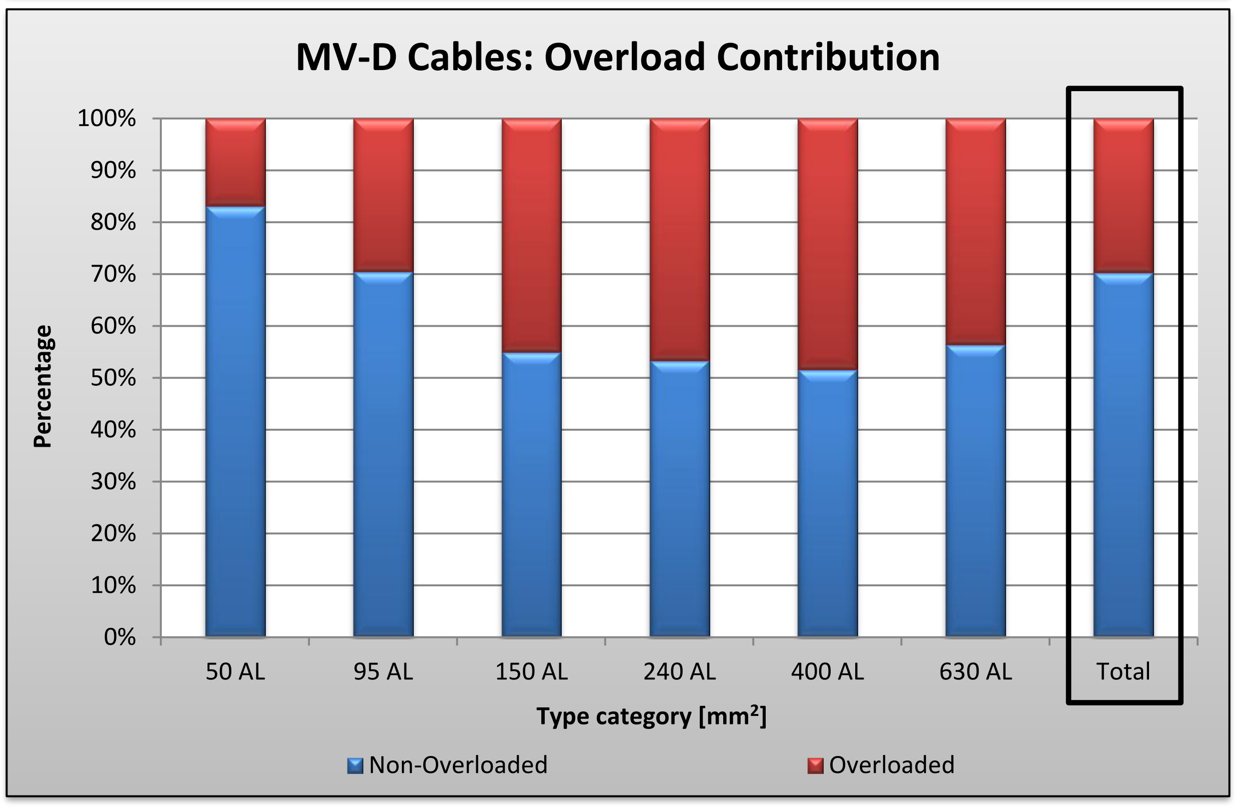


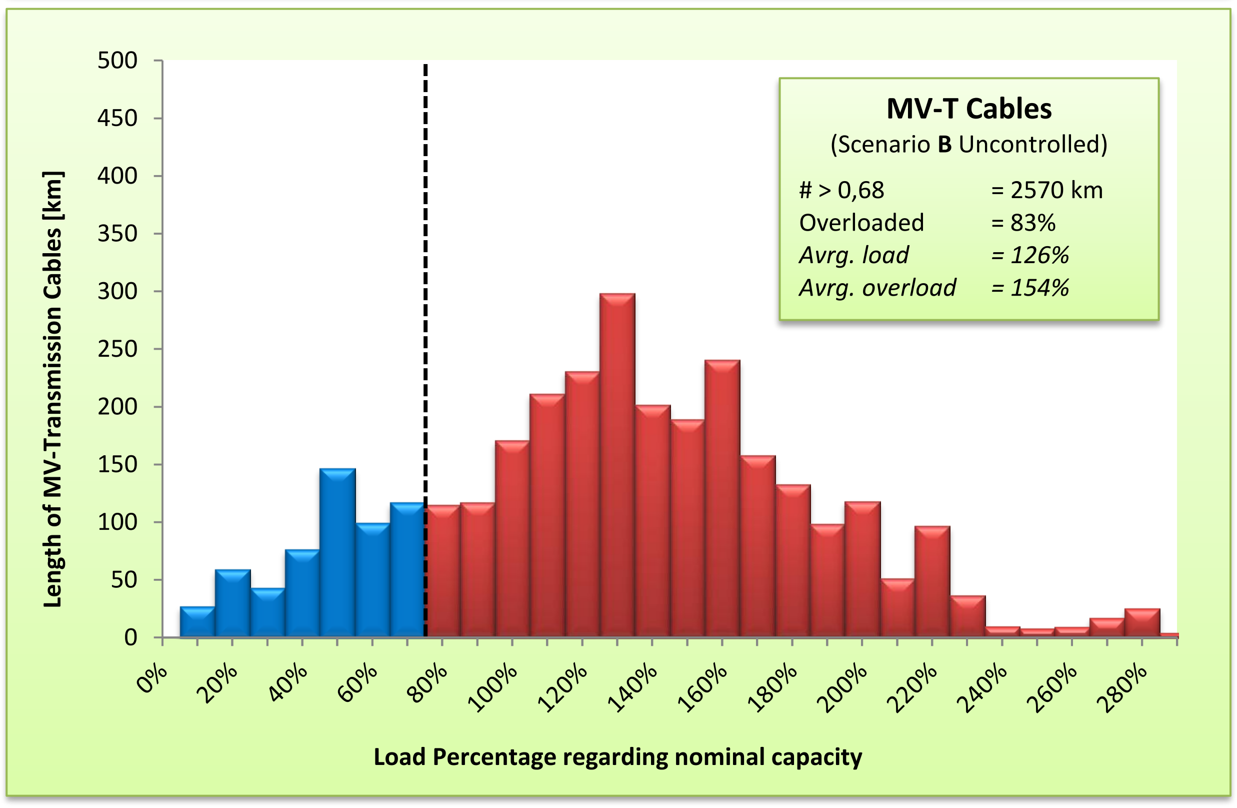
Overview Results Scenario B Uncontrolled

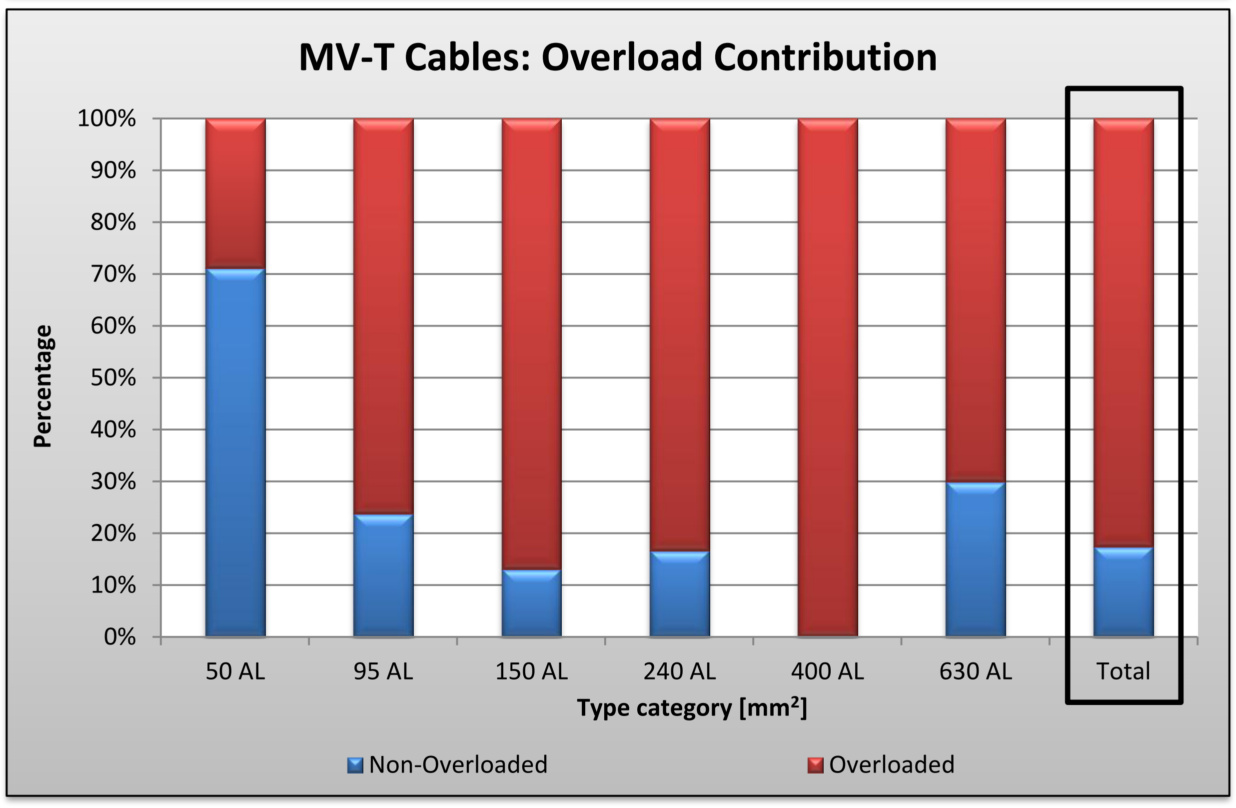


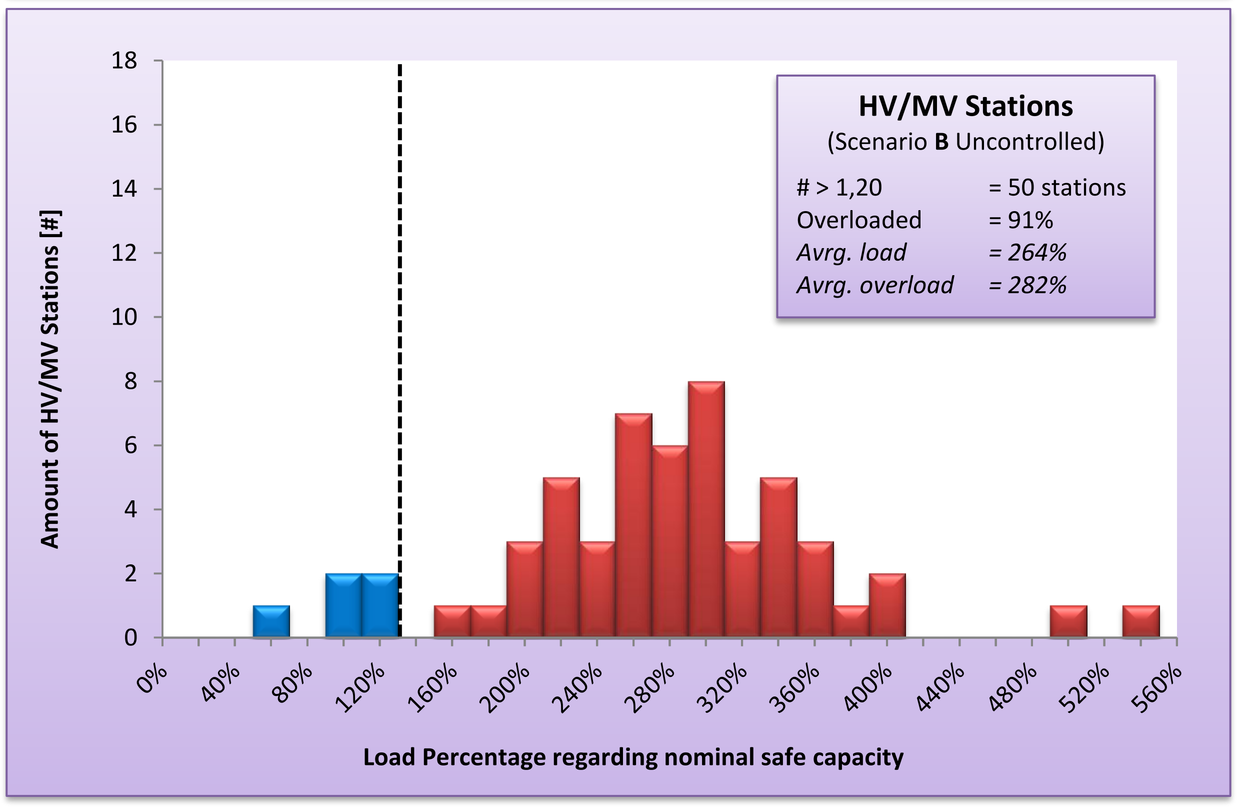


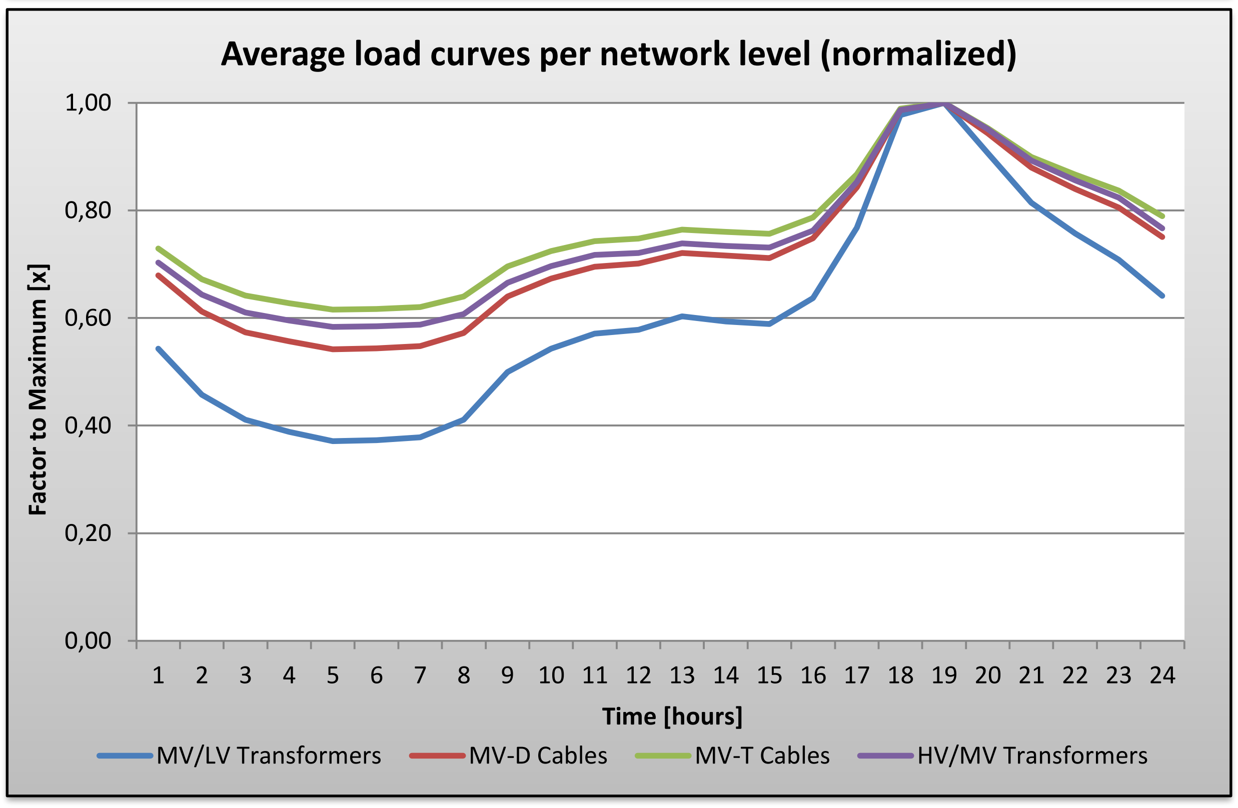




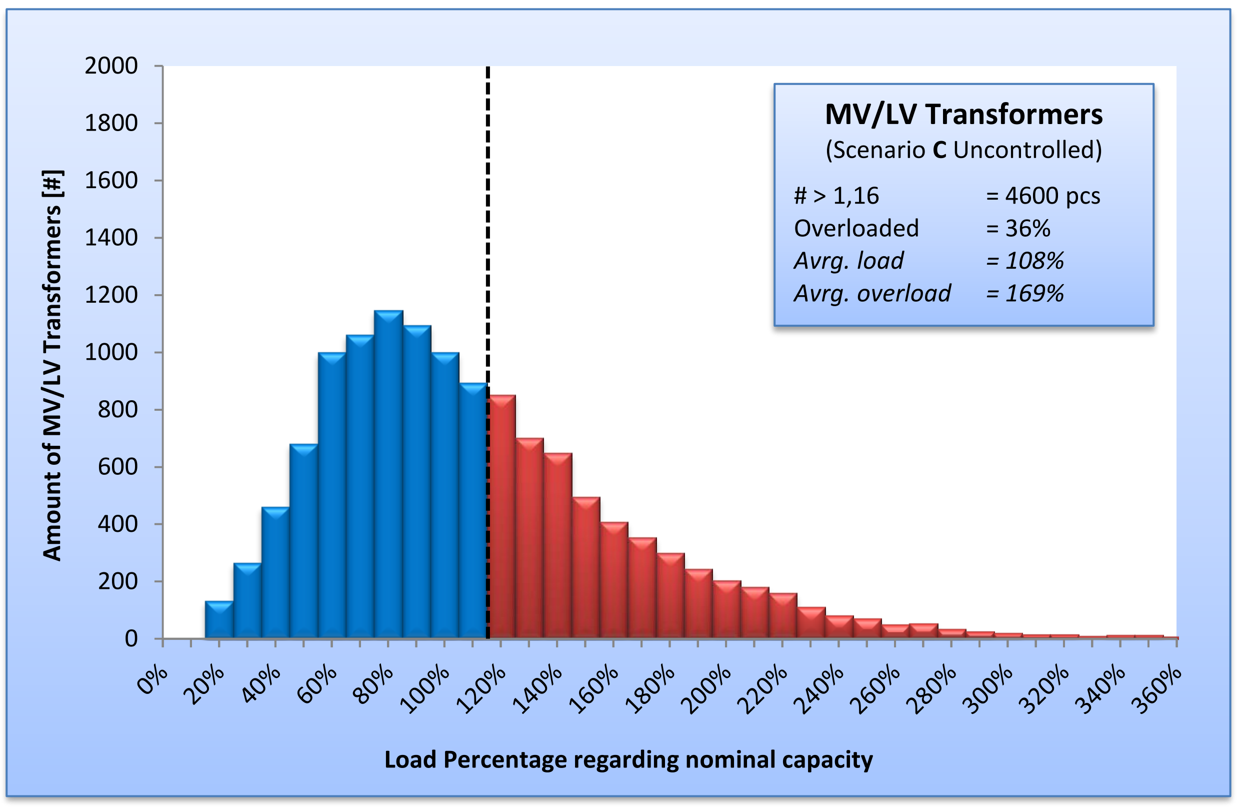


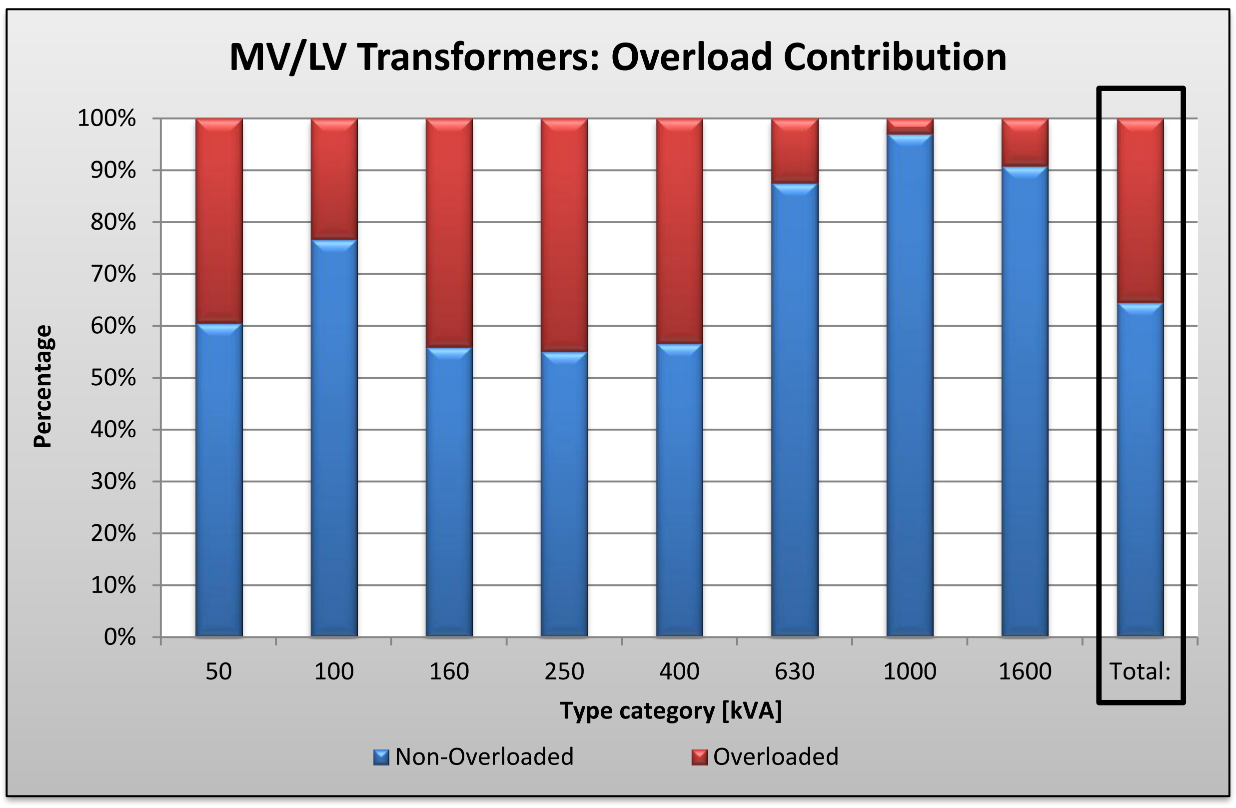


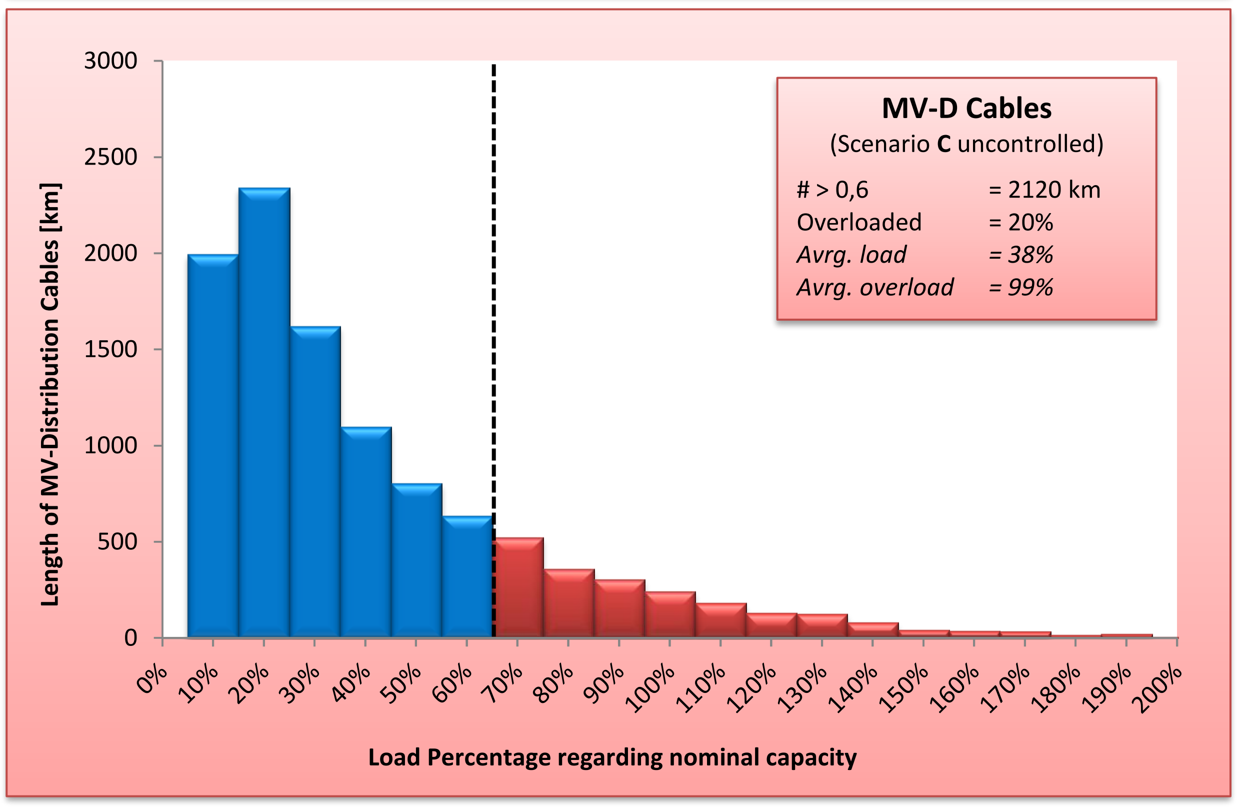


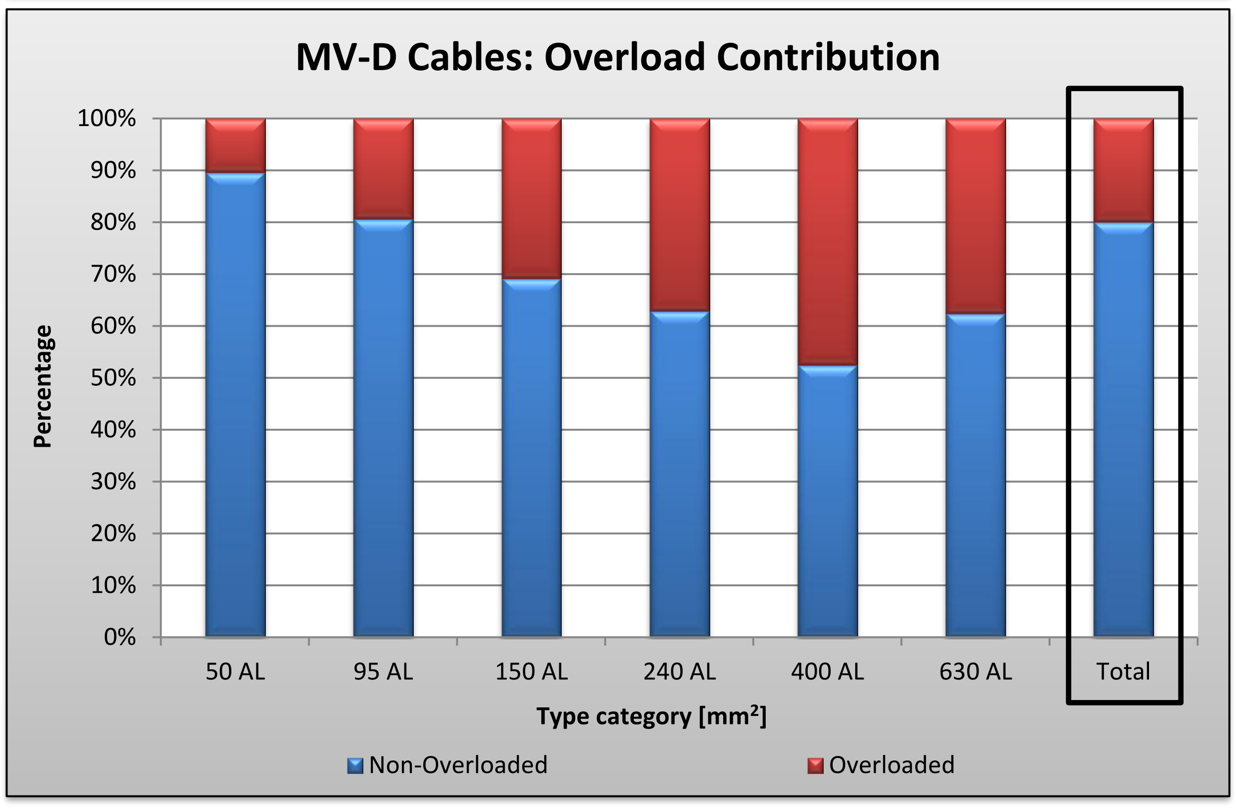


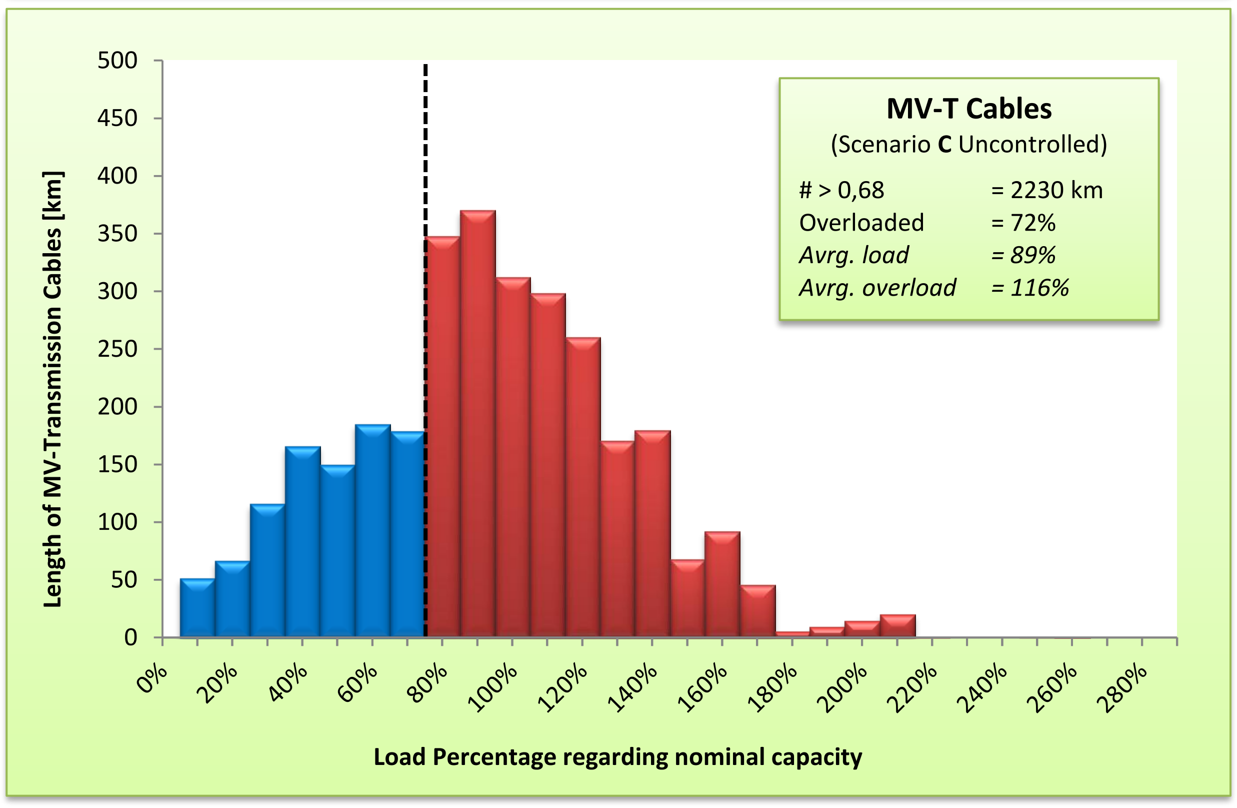
Overview Results Scenario C Uncontrolled

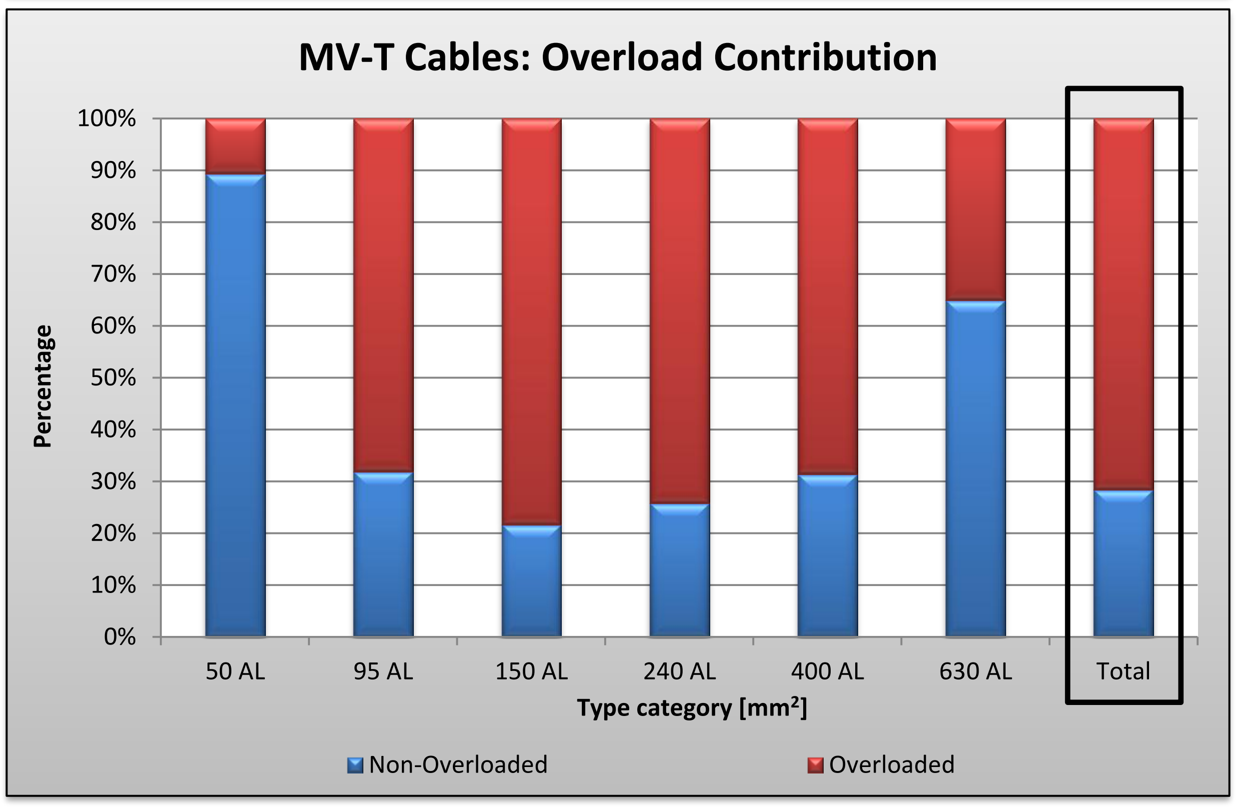


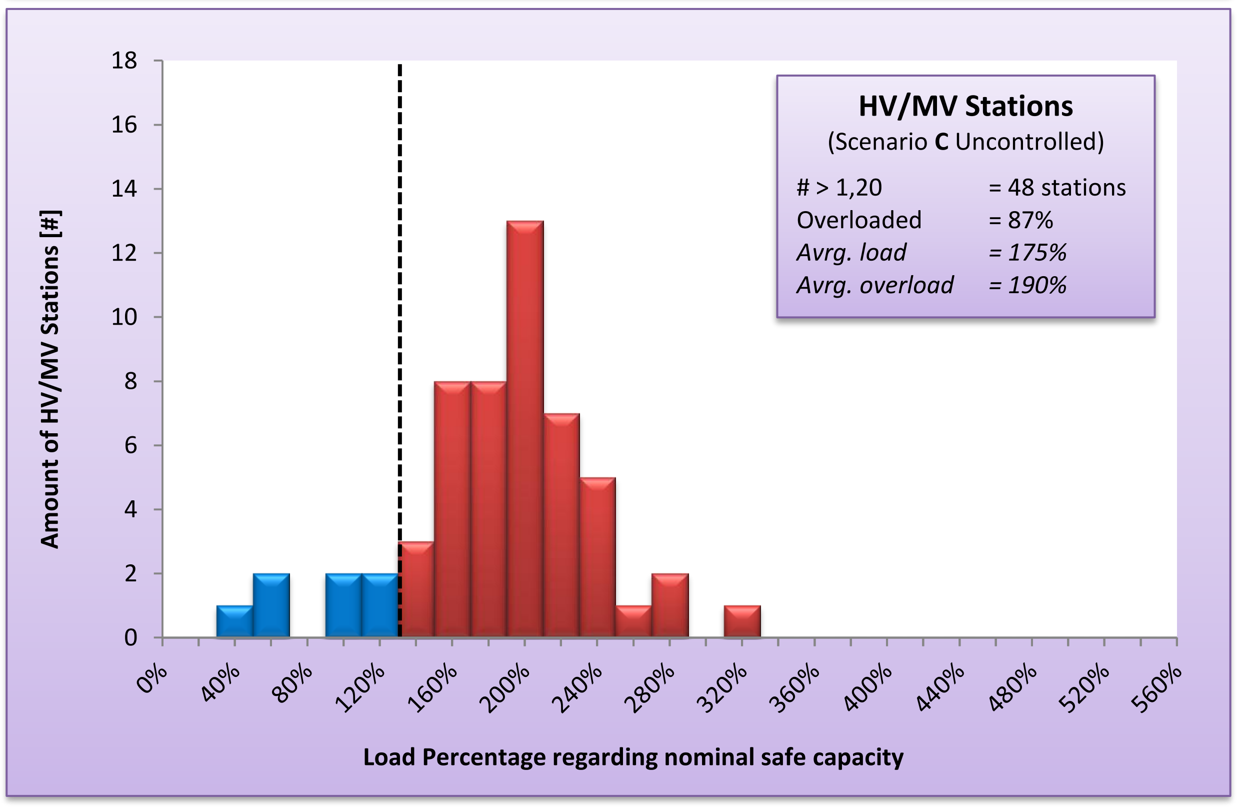


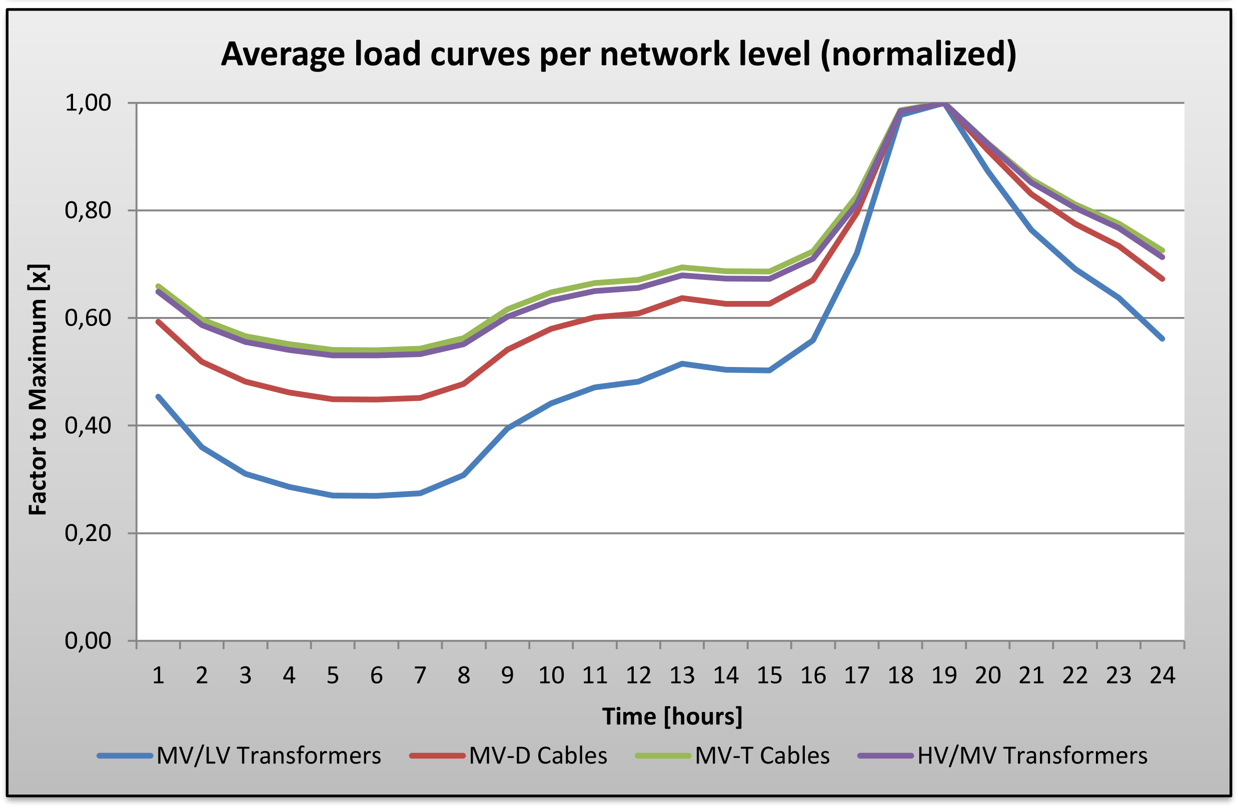




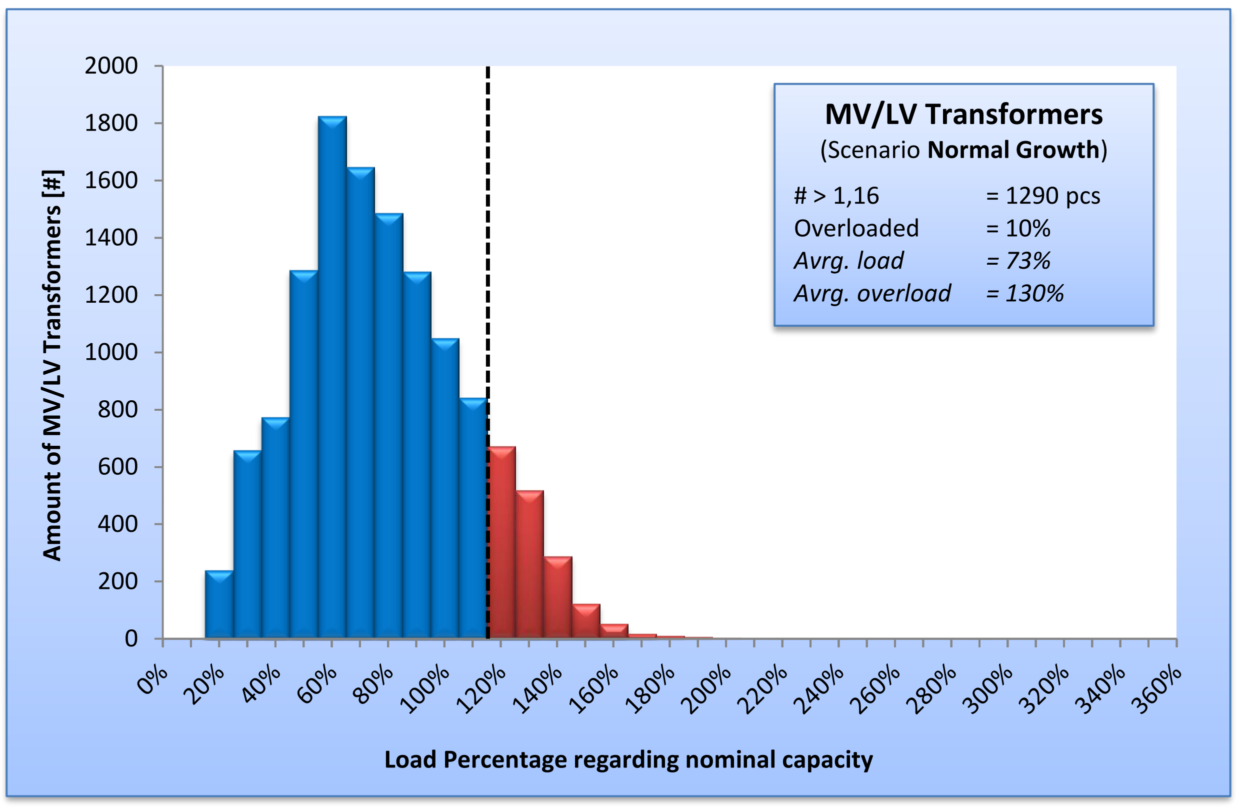


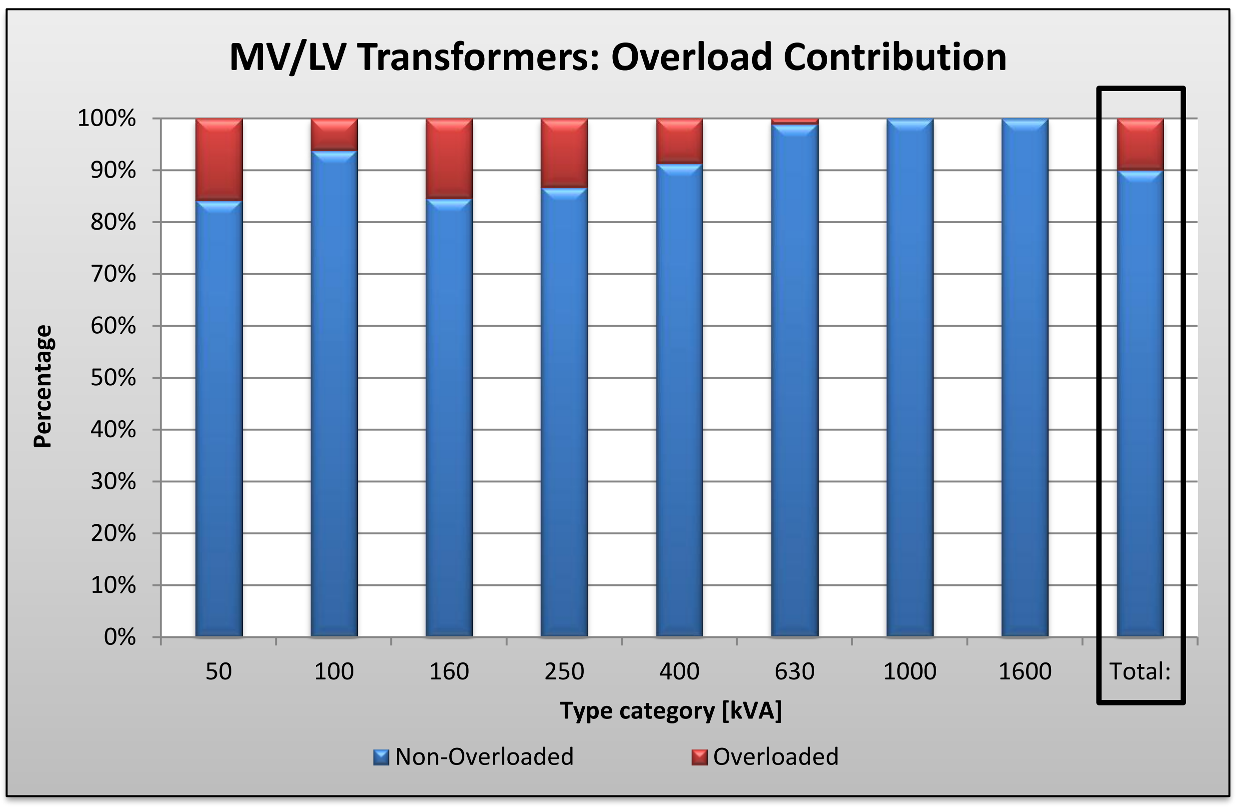


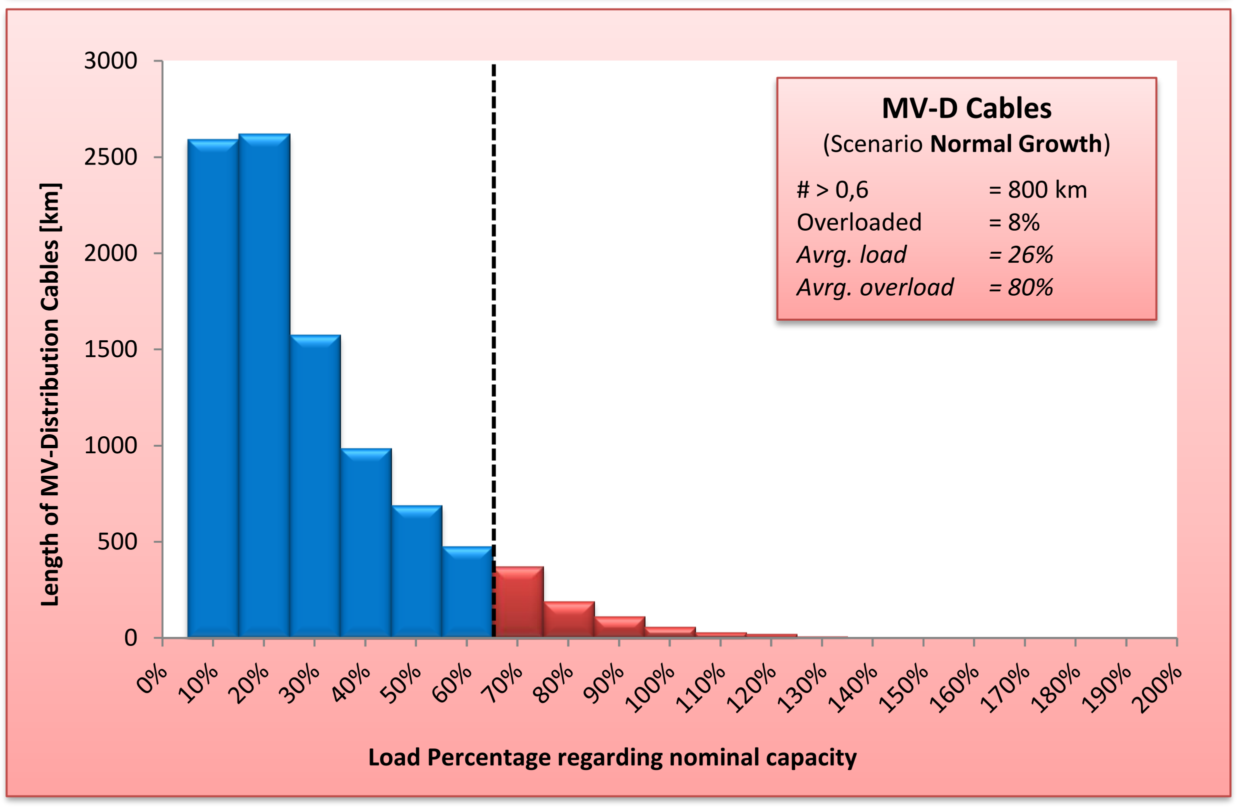


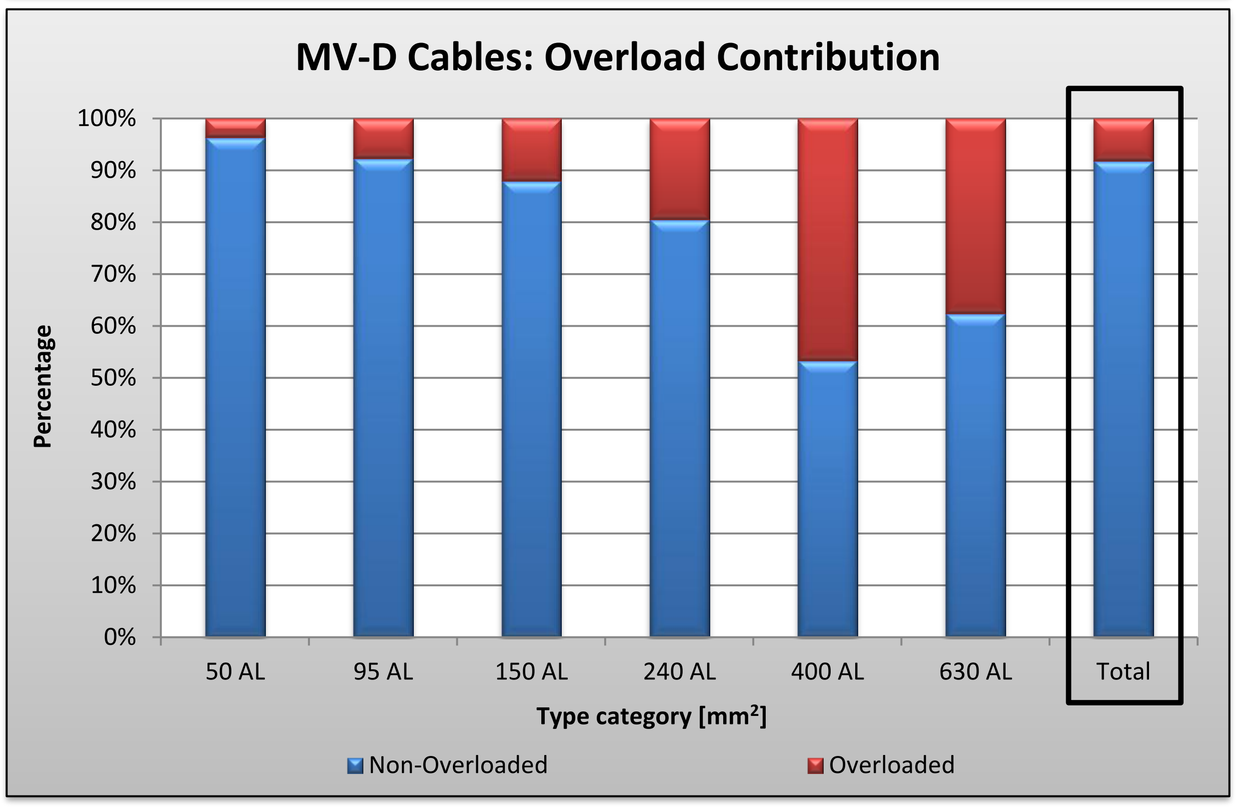


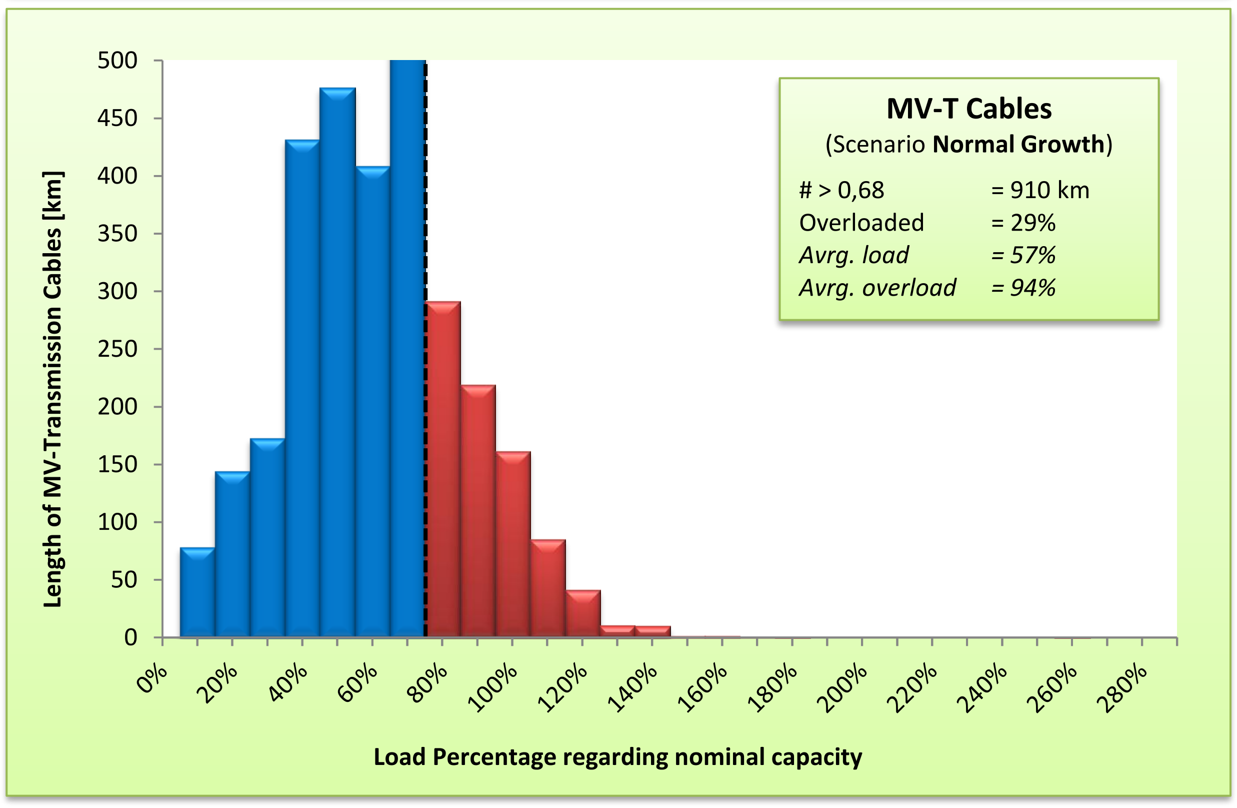
Overview Results Scenario "normal growth"

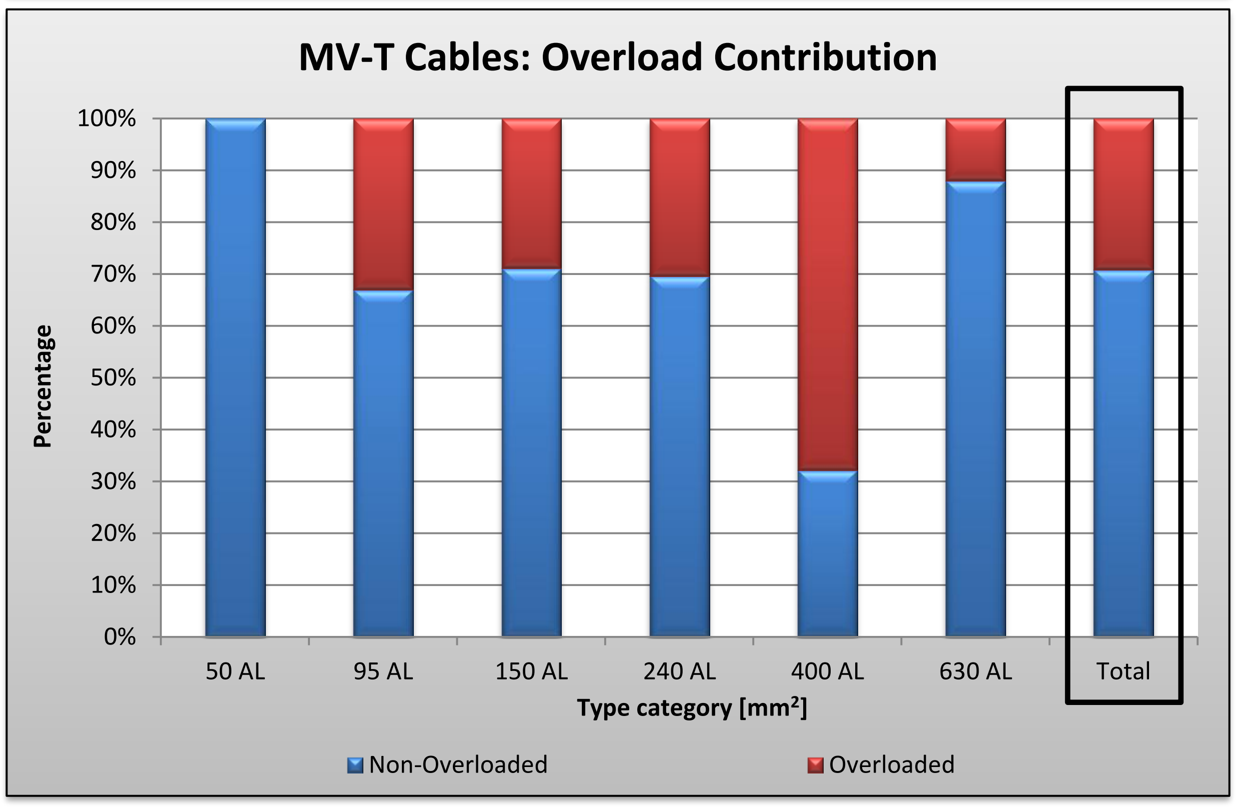


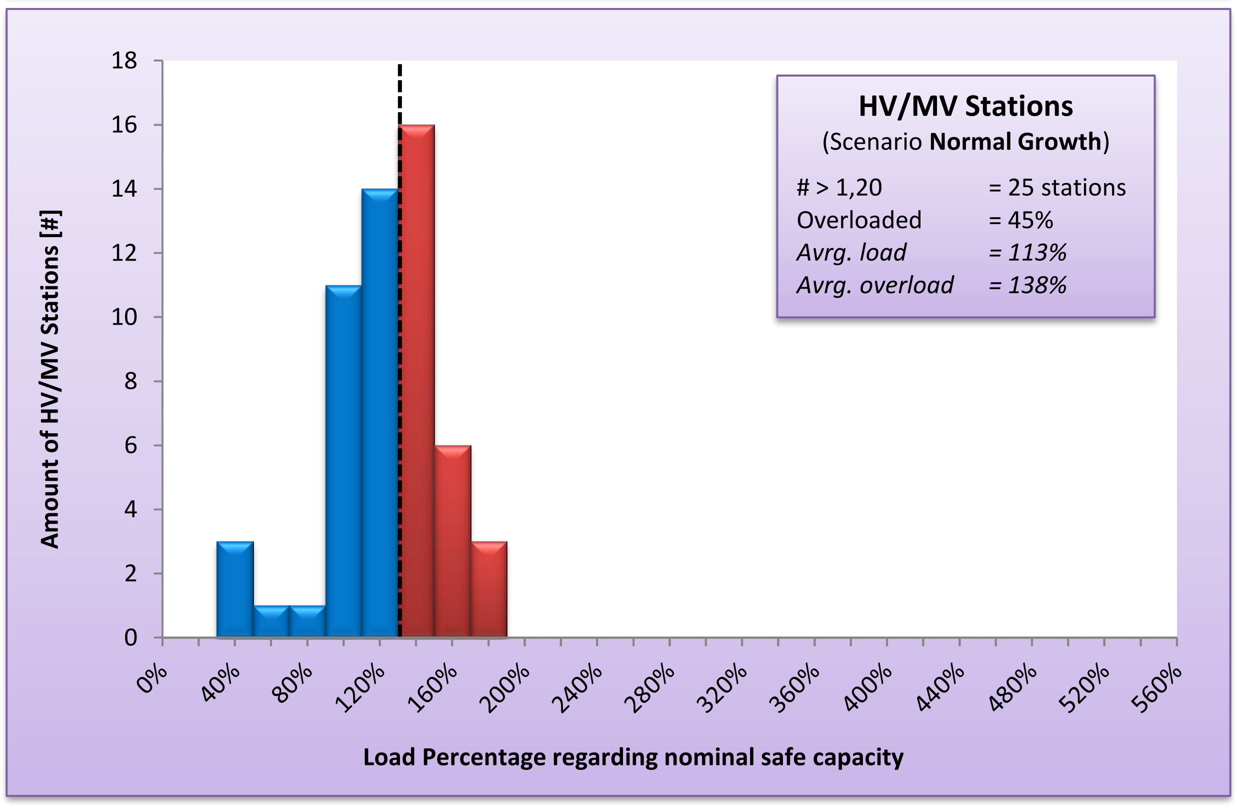


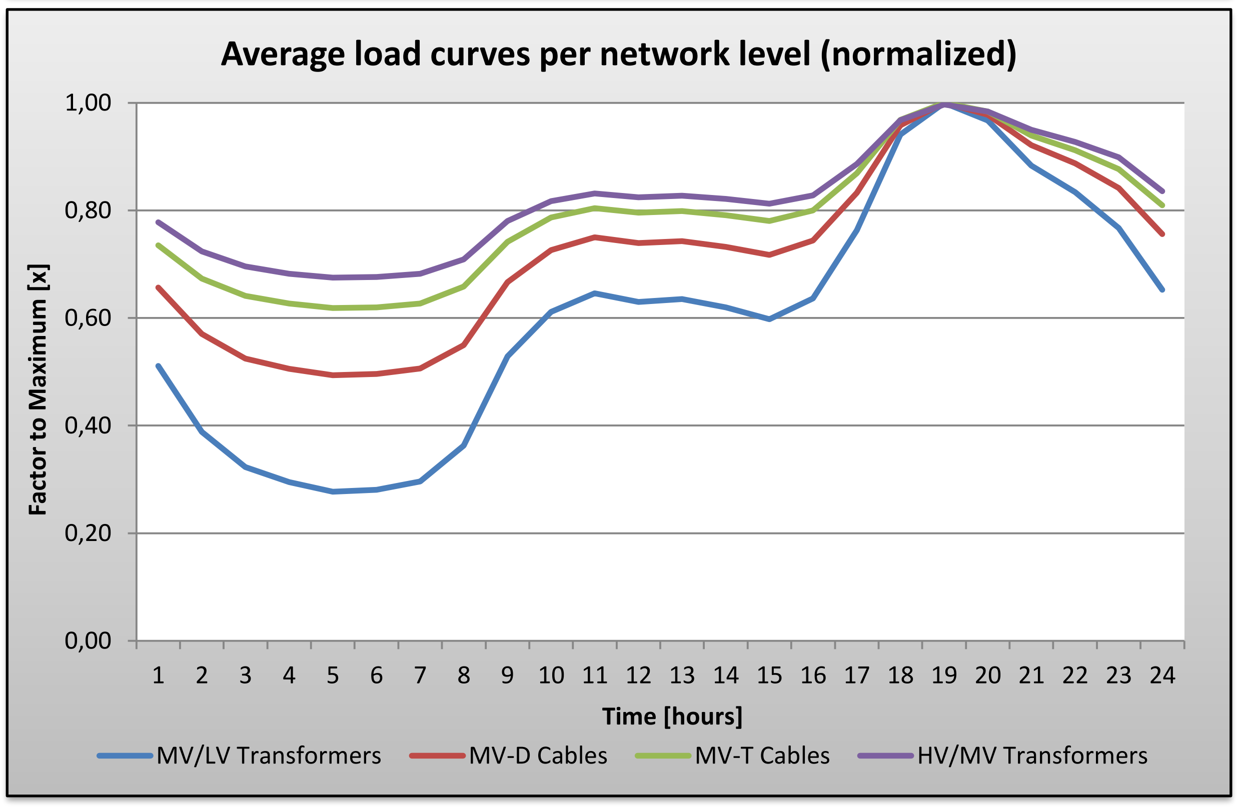




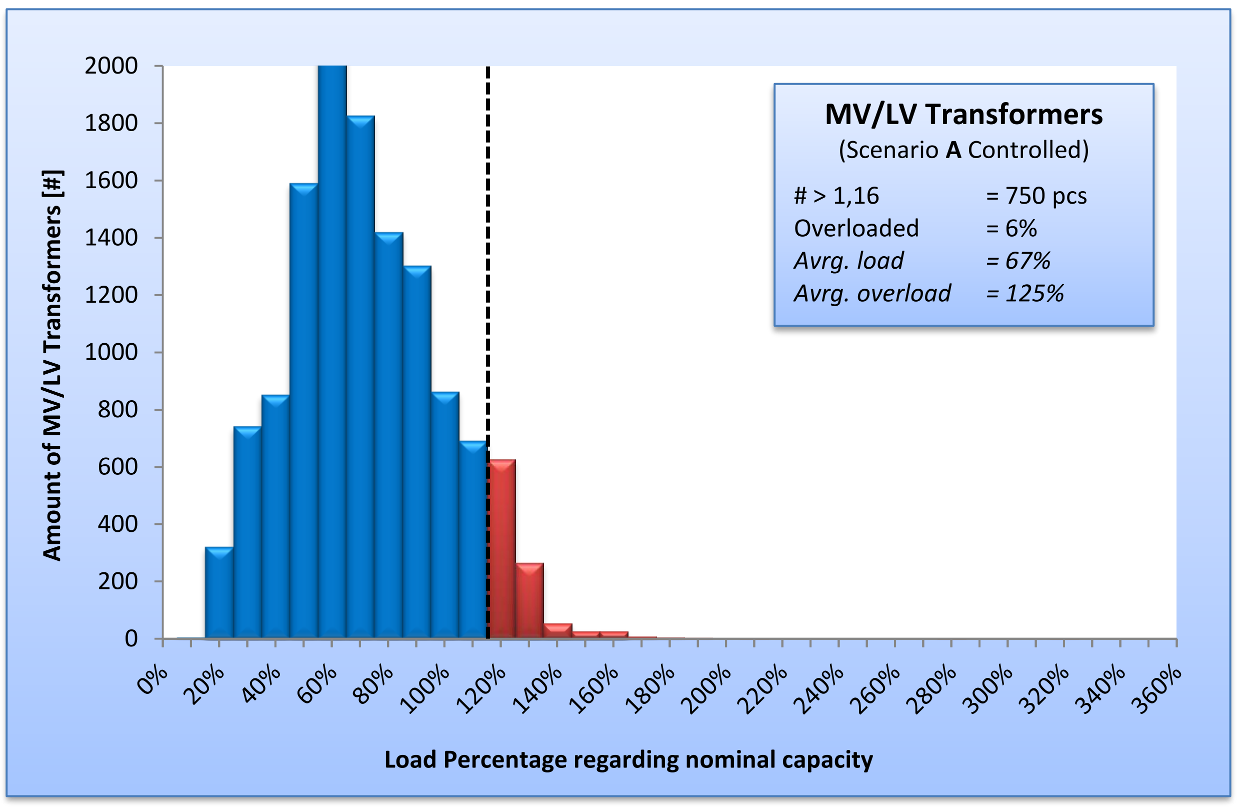


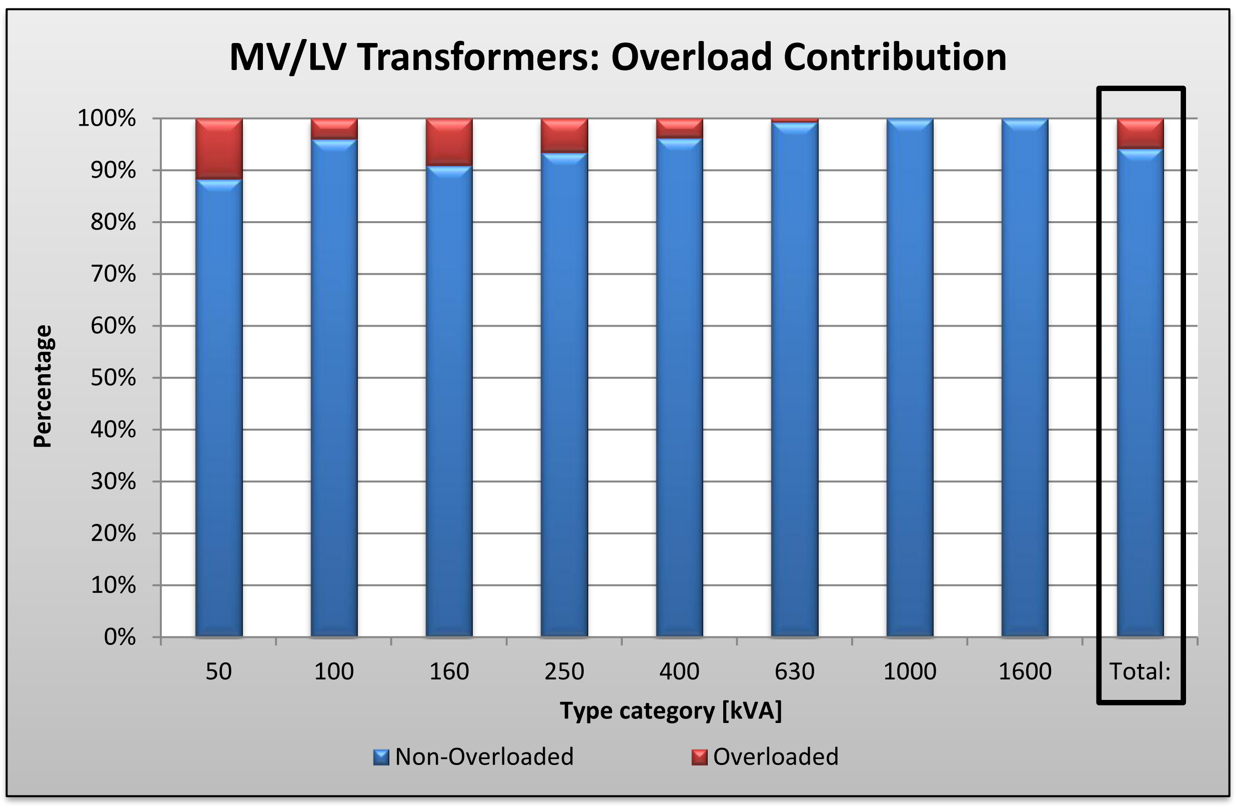


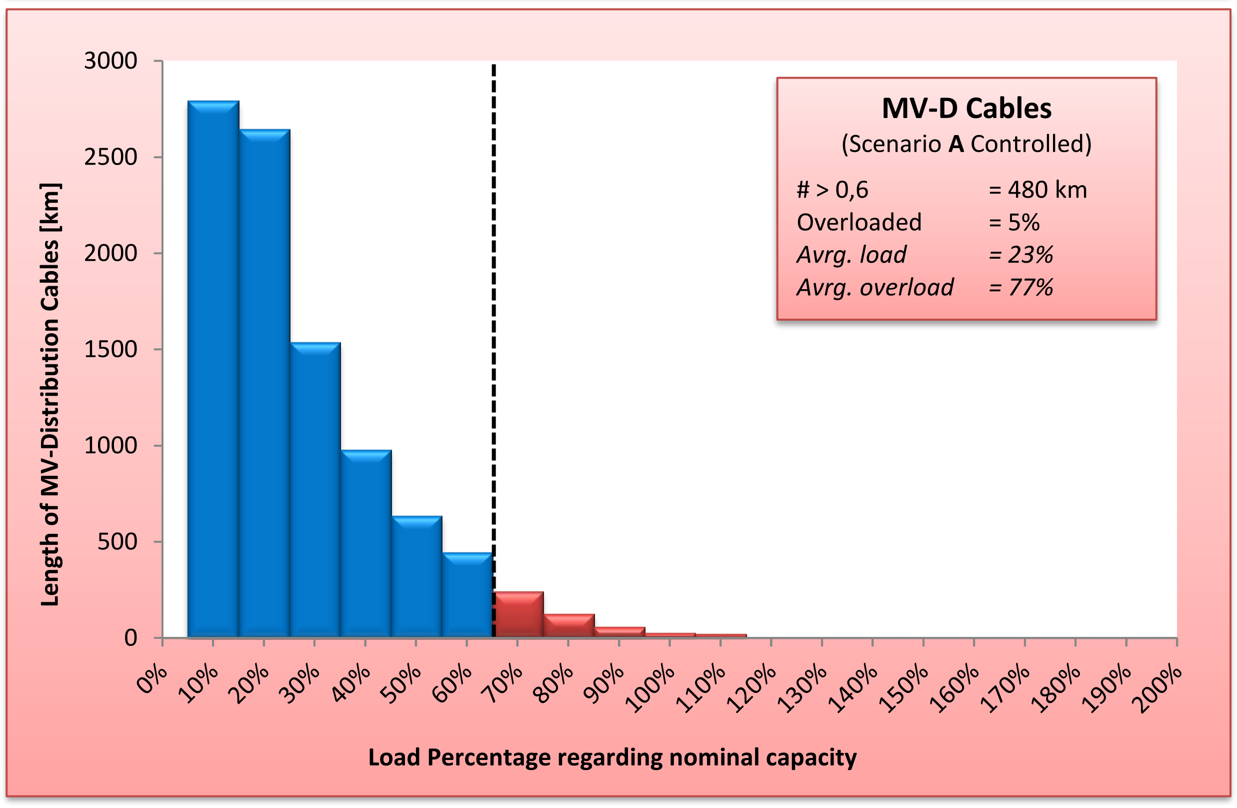


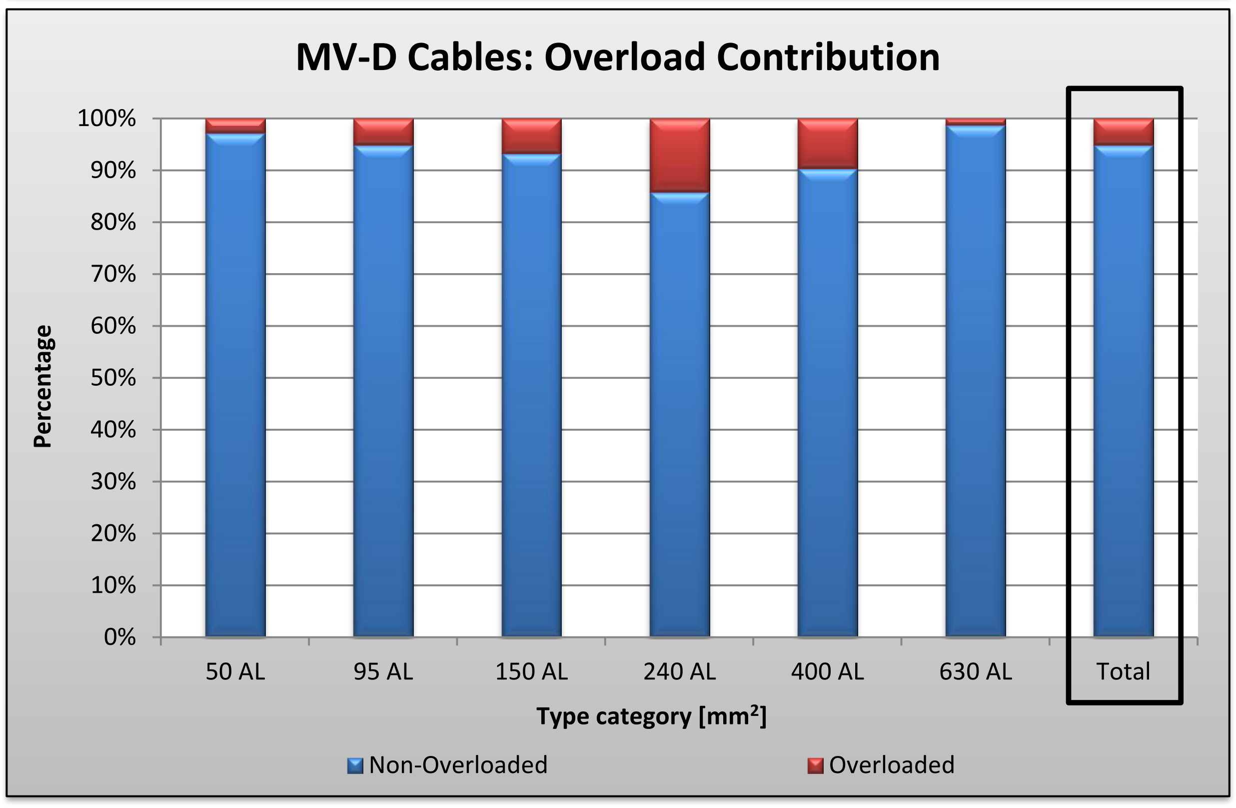


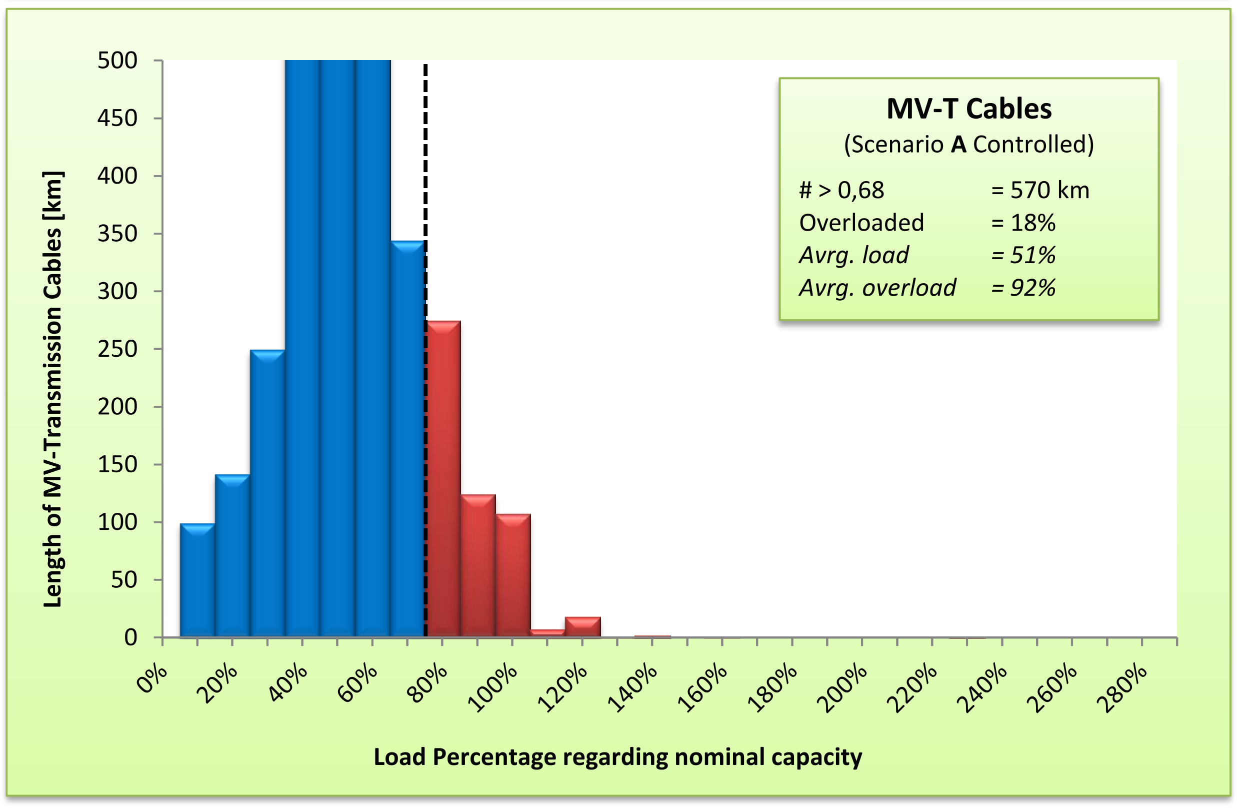
Overview Results Scenario A Controlled

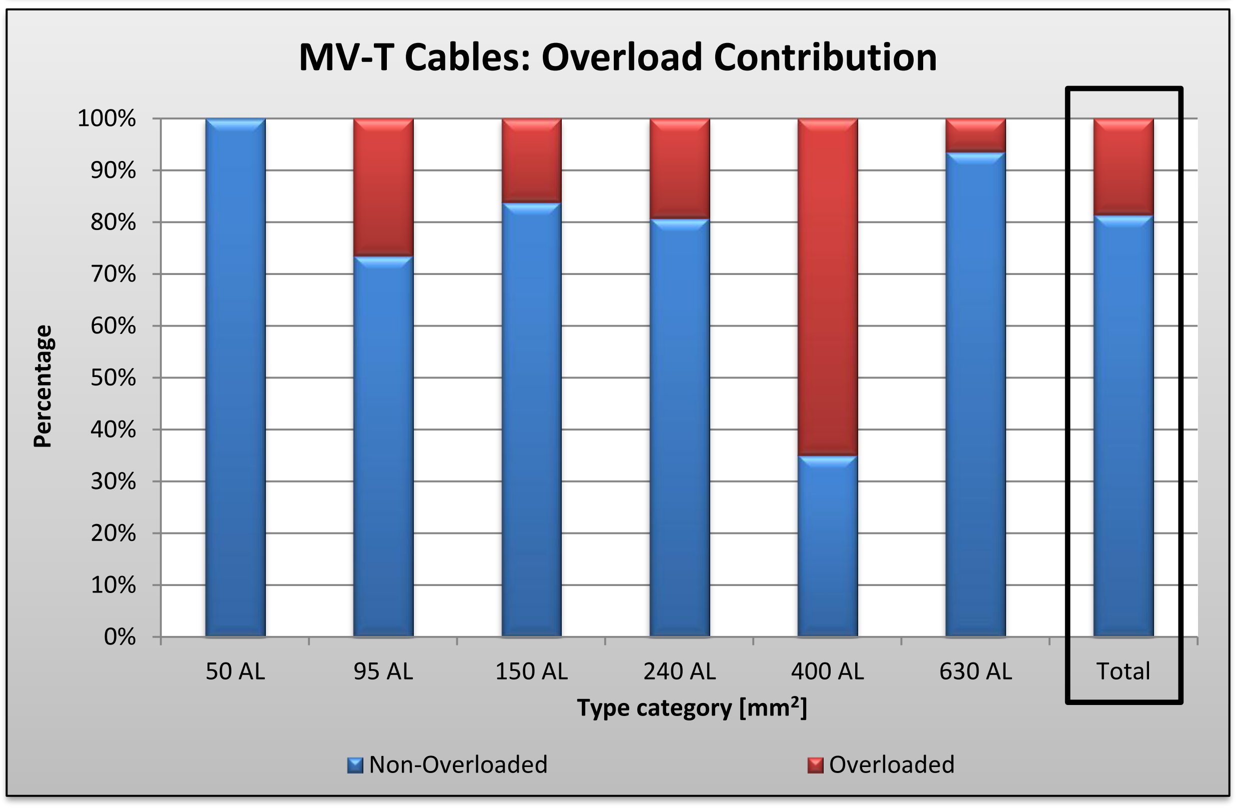


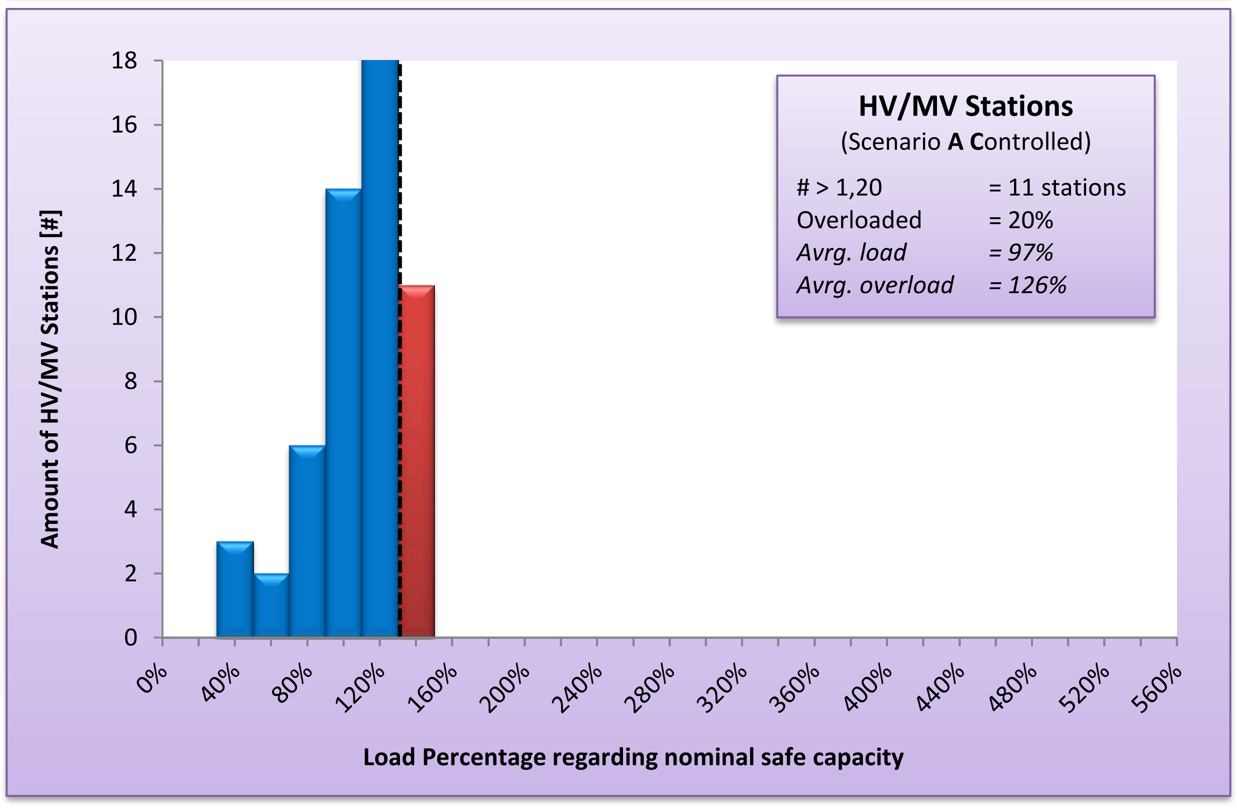


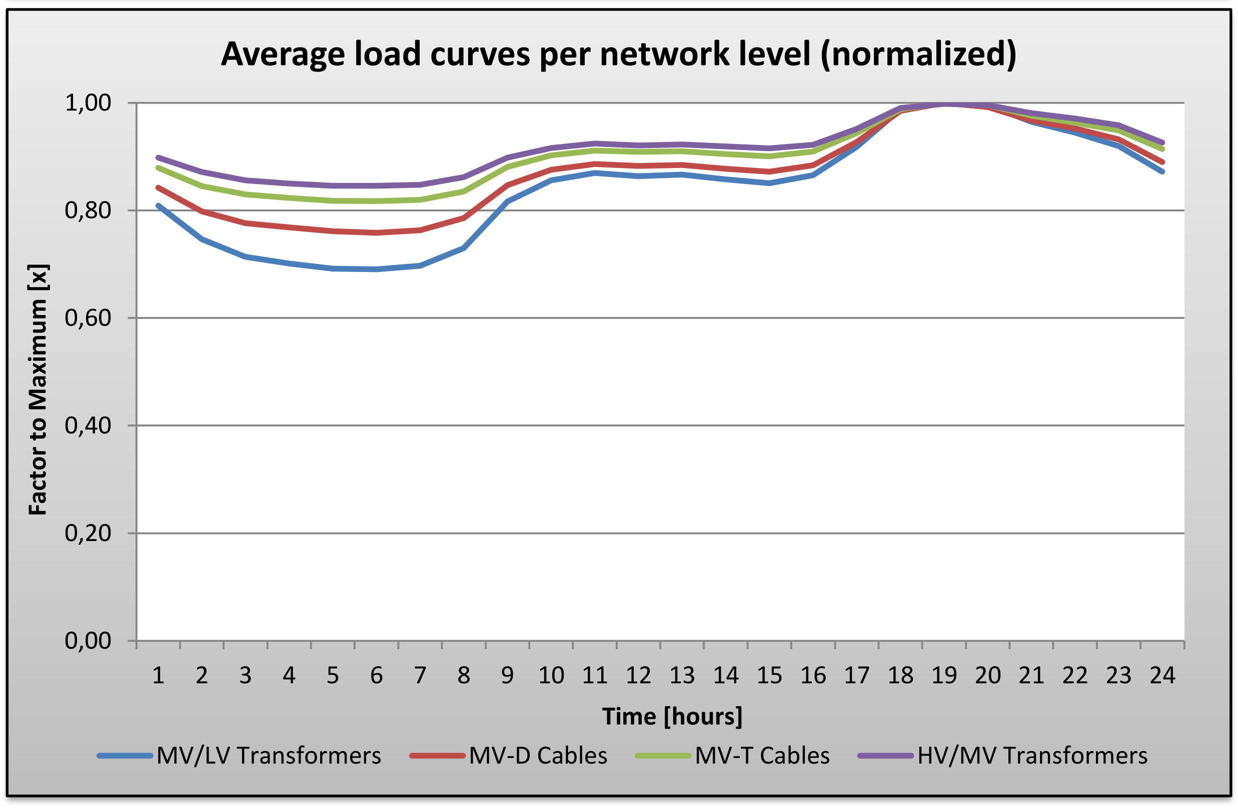




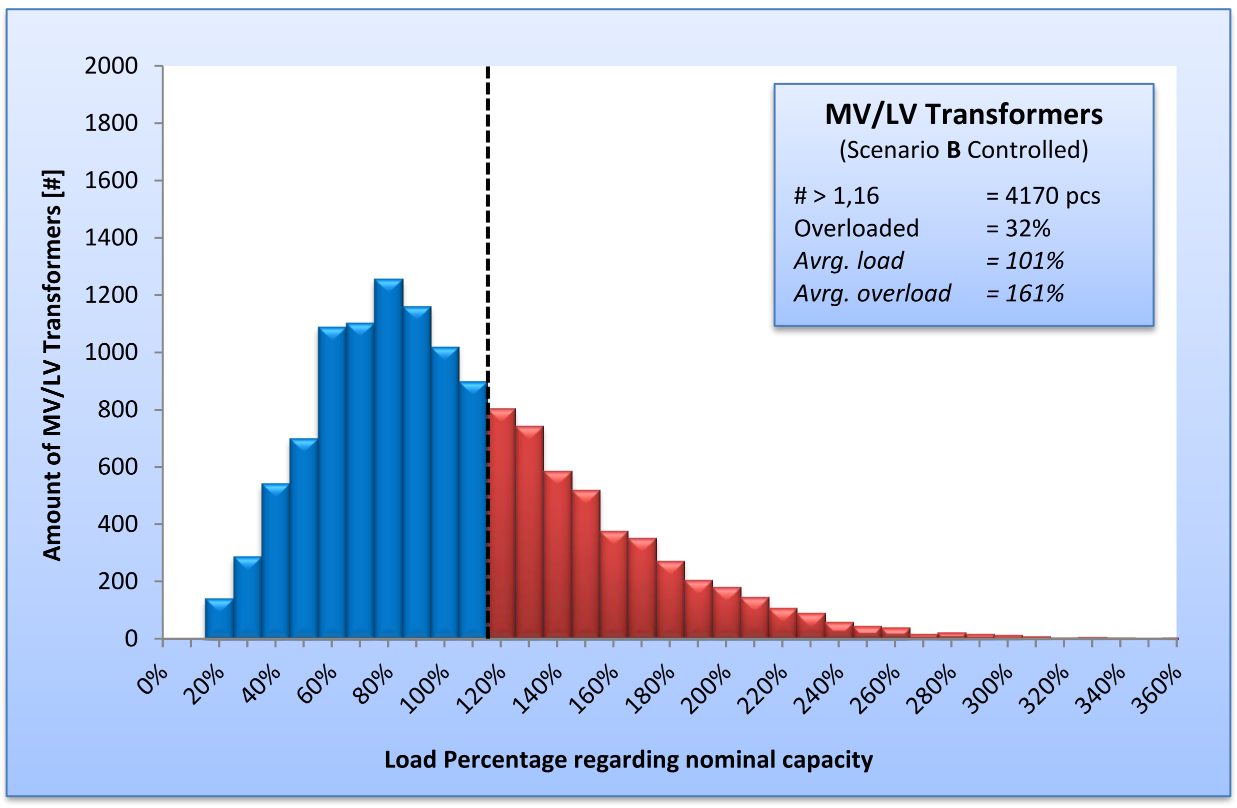


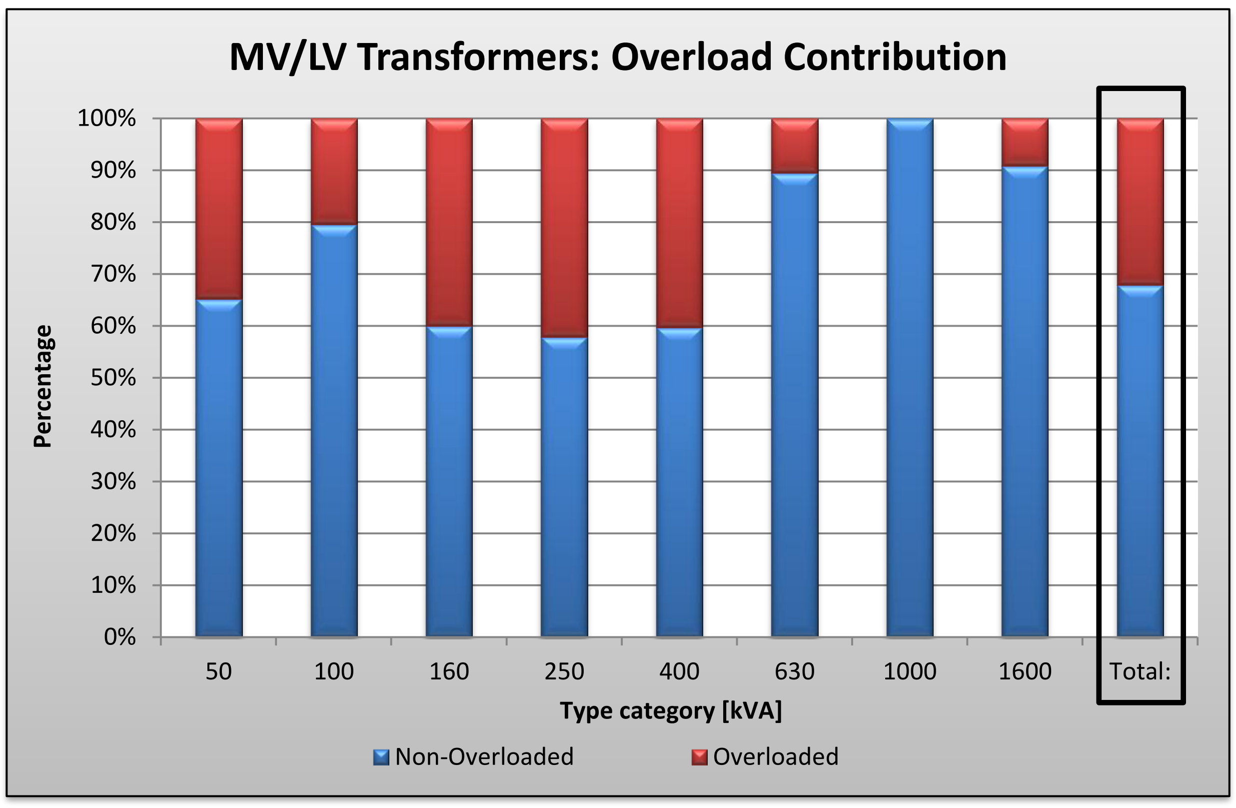


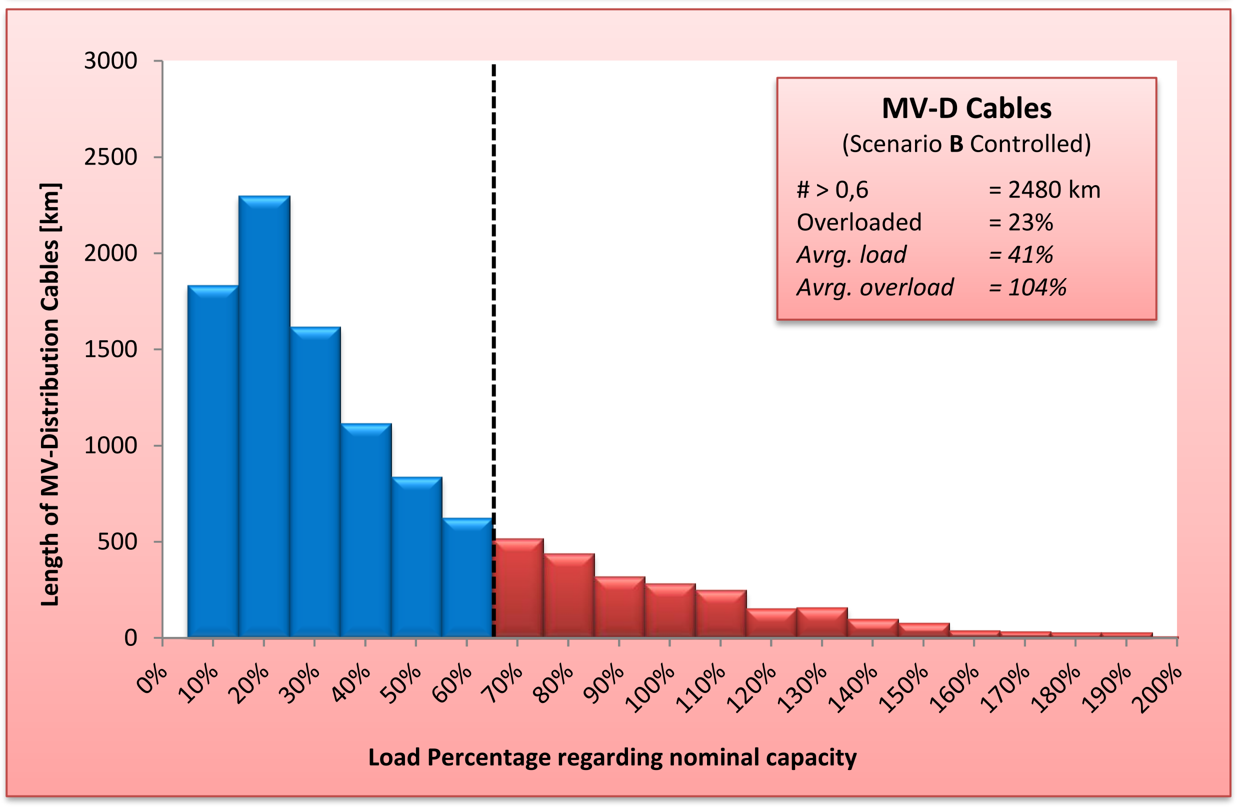


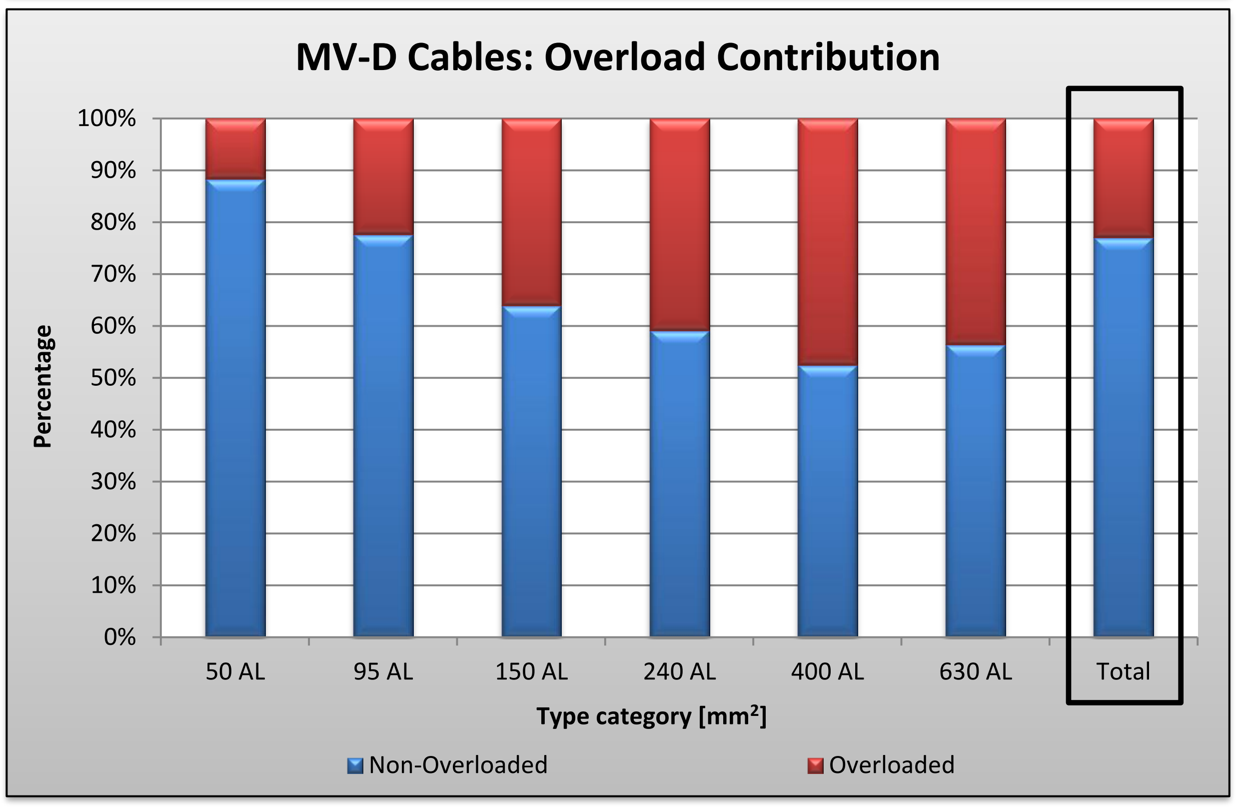


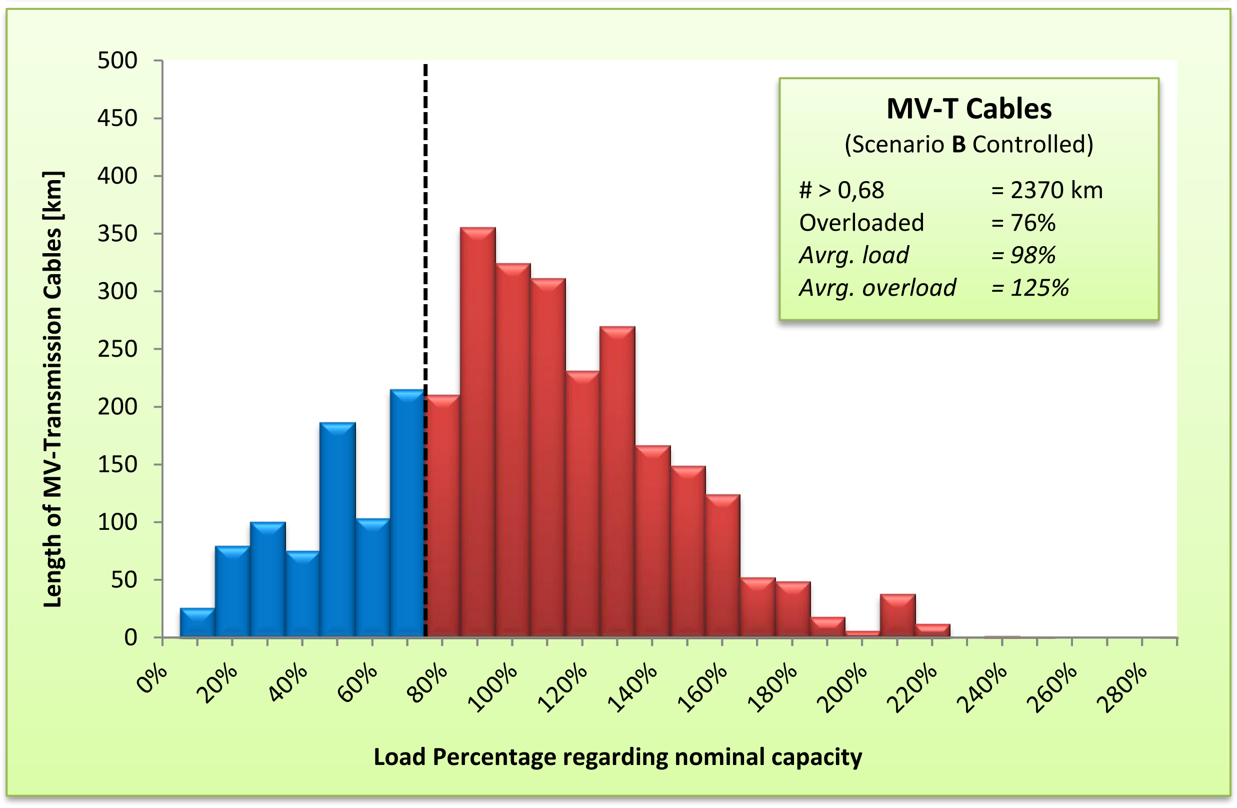
Overview Results Scenario B Controlled

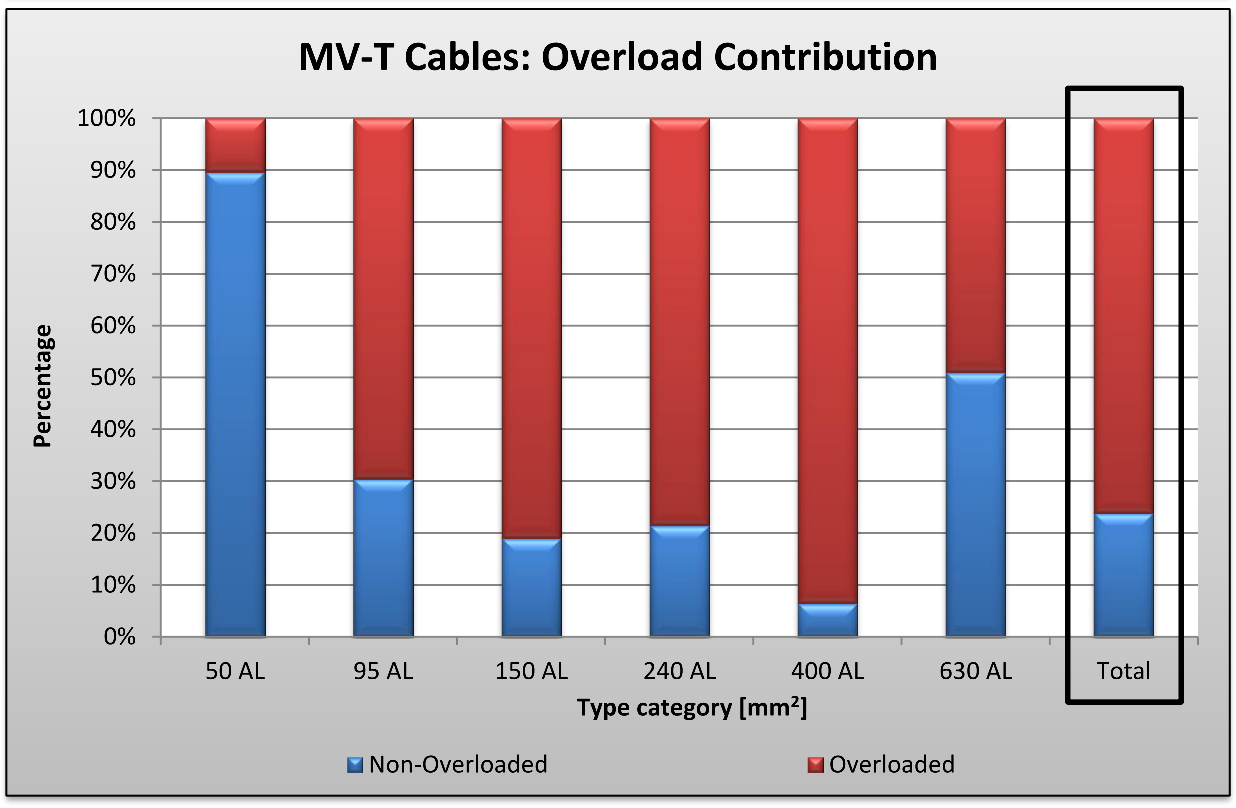


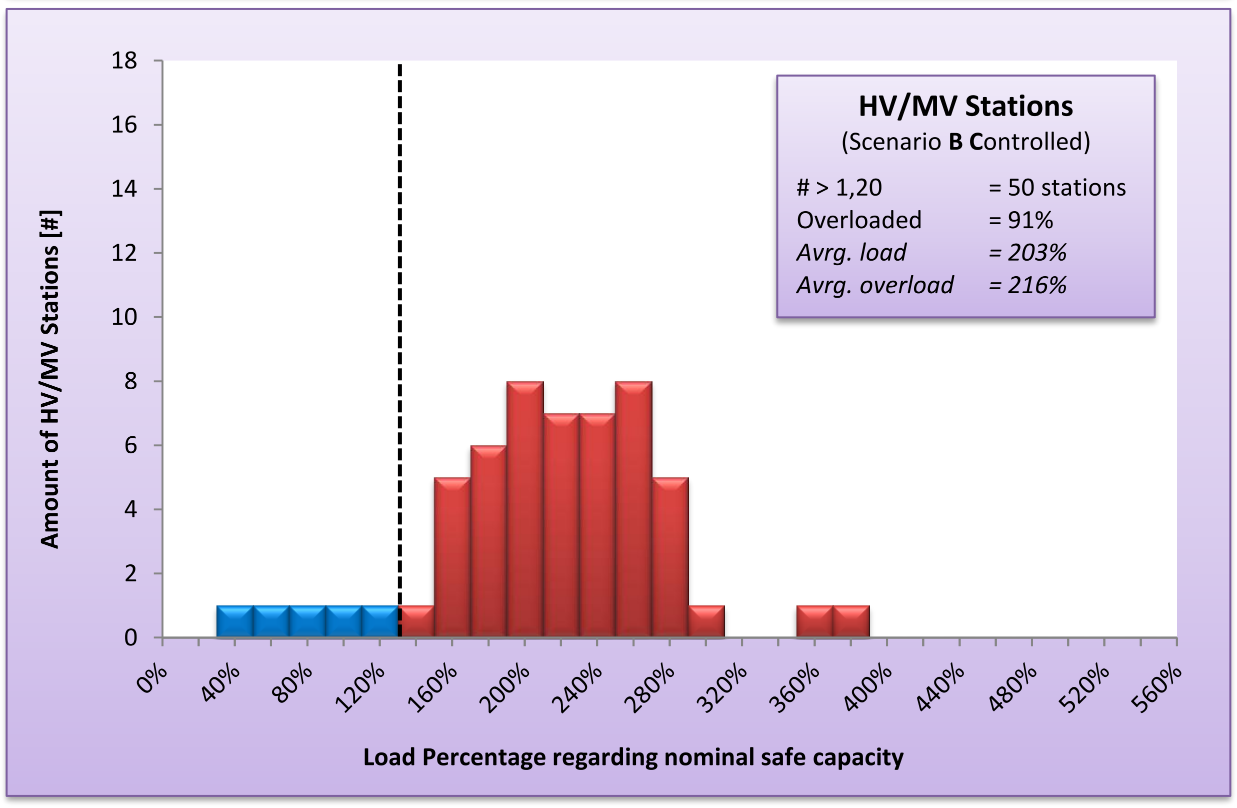


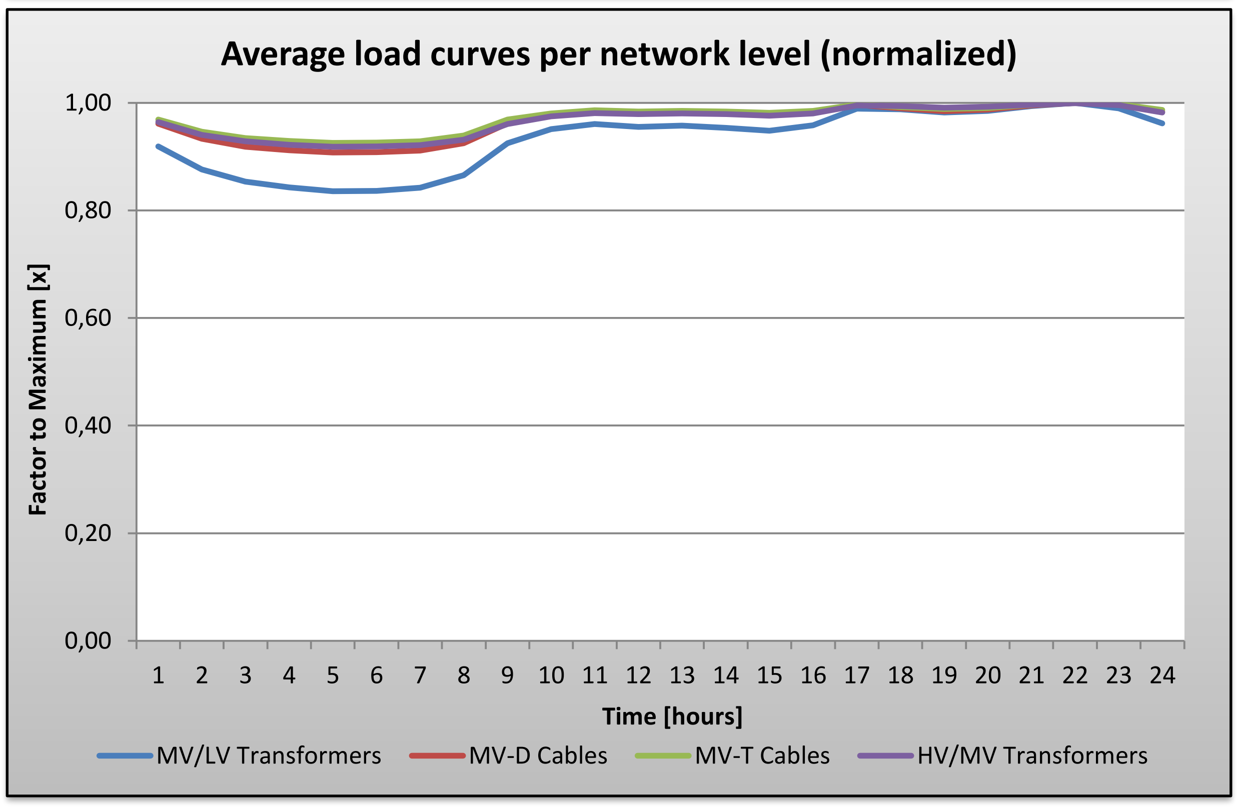












Overview Results Scenario C Controlled