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Optimal placement and sizing of battery storage to increase the PV hosting capacity of low voltage grids

Master Thesis
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Preface

In 2008, the majority of the citizens of Zurich voted in favour of the implementation of the “2000-Watt society” concept, an environmental vision introduced by ETH. The 2000-Watt society concept refers both to the reduction of the overall continuous energy usage to no more than 2000 Watts per person, as well as to the reduction of the carbon footprint to no more than 1 tone CO$_2$ equivalent per person by 2050. As of 2015, ewz, the electricity distribution company of Zurich, with its product “ewz.solarzüri”, is offering to its customers the opportunity to co-finance the construction of photovoltaic (PV) plants in their neighbourhood and receive their respective share of the produced electricity during the plant’s lifetime.

In this context, the PV penetration in the distribution grid of the city of Zurich is expected to rise with a growing pace over the next years. This can bring challenges to the existing electricity grid infrastructure and lead to the violation of several technical constraints such as voltage band and transformer or cable loadings. Moreover, the expected increase in the number of electrical vehicles can also push the existing distribution grid to its limits.

From the distribution system operator’s (DSO) point of view, the conventional way of integrating considerable amounts of distributed generation and electric vehicles would require significant investments for the network reinforcement and expansion. The installation of battery storage in the low voltage level is an interesting alternative for solving the aforementioned technical problems and could therefore avoid or at least reduce or postpone, the need for extensive conventional network reinforcements. The decreasing battery prices together with the plethora of versatile services that a battery system can offer are rendering this solution more and more attractive for the electricity utilities. Already, various projects involving battery storage as a PV integration measure are running, such as the pilot project of ewz in Dora-Staudinger-Strasse, where the behaviour of a battery system in conjunction with PV plants will be studied.

This thesis will address the question “What is the cost-optimum battery storage allocation in order to integrate the full PV potential of a LV grid area?”. Furthermore, the effect of Active Power Curtailment (APC) as a PV integration measure in combination with battery storage will be examined from a DSO perspective.
Abstract

The purpose of this thesis is to investigate the cost-optimal placement and sizing of battery storage as a PV integration measure in the distribution grid level. Additionally, potential synergies between PV generation, battery storage, smart PV curtailment and electric mobility are also explored within this thesis. Accordingly, a versatile optimization tool has been developed in order to identify potential battery location and size combinations that increase the PV hosting capacity of a low voltage grid at minimum cost. The optimization tool is based on the two basic Optimal Power Flow (OPF) algorithms: AC OPF and DC OPF. The high computation times that an AC OPF requires, as well as the many simplifications assumed in the DC OPF, necessitate the development of hybrid methods that render the optimization problem tractable without neglecting crucial operational data (e.g. voltages).

In the project PV Leimbach, ewz compares potential PV integration measures on a technical as well as economic basis. In this context, one substation area of Leimbach is chosen for the demonstration of the optimization tool in a real network. Measurement data from a local transformer station and PV plants in the city of Zurich for 2013 are utilized as inputs for the optimization. Moreover, scenarios including electric mobility load curves extracted by a model developed at ETH Zurich are also investigated.

The functionality and the performance of the developed methods is assessed for a benchmark network of reduced size and a single method that provides the best trade-off between computational time efficiency and accuracy of the results is chosen for implementation on the real case-study network. The cost optimal battery storage placement and sizing is investigated, while the battery storage dispatch is assessed by a second optimization algorithm that aims at the maximization of the degree of self-sufficiency of the LV grid area. In the second part of the simulations, various sensitivity analyses are carried out to investigate different scenarios and parameter combinations.

The results of this work show that a DSO would have to bear considerable costs in case the problems caused by PV penetration are addressed exclusively by battery storage installation. The implementation of even low curtailment levels could result to a drastic reduction of these costs with negligible energy losses. Assuming a high PV penetration, a similar reduction of the required battery capacity results with the introduction of a high share of electric cars. Finally, it can be concluded that the implementation of hybrid AC and DC OPF methods for battery placement and sizing problems can lead to
a significant decrease in computation time without sacrificing crucial information about the network.

**Key Words:** optimal battery sizing and placement, optimal battery dispatch, PV penetration, active power curtailment (APC), electromobility, LV network, hybrid OPF methods.
Kurzfassung

Der Zweck dieser Masterarbeit ist es, die kostenoptimale Platzierung und Dimensionierung des Batteriespeichers als PV-Integrationsmaßnahme auf Verteilnetzebene zu untersuchen. Überdies werden in dieser Masterarbeit potenzielle Synergien zwischen der PV-Erzeugung, dem Batteriespeicher, der PV-Abregelung und Elektromobilität analysiert. Entsprechend wurde ein vielseitiges Optimierungswerkzeug entwickelt, um verschiedene Möglichkeiten in Bezug auf Batterieposition und -größe zu überprüfen, um so die PV-Aufnahmekapazität eines Niederspannungsnetzes mit minimalen Kostenaufwand zu vergrößern. Das Optimierungswerkzeug basiert auf den zwei grundlegenden optimalen Lastflussalgorithmen: AC OPF und DC OPF. Die hohen Berechnungszeiten, die ein AC OPF erfordert wie auch die vielen Vereinfachungen, die im DC OPF angenommen werden, erfordern die Entwicklung von hybriden Methoden, die das Optimierungsproblem lösbar machen ohne entscheidende betriebliche Daten (z.B. Spannungen) zu vernachlässigen.


Die Funktionalität und die Performance der entwickelten Methoden werden für ein Benchmarknetz von reduzierter Grösse evaluiert. Im Anschluss wird die Methode, welche den besten Kompromiss zwischen Berechnungszeiteffizienz und Genauigkeit der Ergebnisse erzielt, für die Durchführung im echten Fallstudiennetz gewählt. Die kostenoptimale Platzierung und Dimensionierung der Batteriespeicher wird untersucht, während der betriebliche Batteriespeichereinsatz durch einen zweiten Optimierungsalgorithmus bewertet wird, der auf die Maximierung des Grades der Unabhängigkeit des Niederspannungsgebiets abzielt. Im zweiten Teil der Simulationen werden verschiedene Sensitivitätsanalysen ausgeführt, um verschiedene Szenarien und Parameterkombinationen zu untersuchen.

Die Ergebnisse dieser Arbeit zeigen, dass ein Verteilnetzbetreiber beträchtliche Kosten

**Schlüsselwörter:** optimale Platzierung und Dimensionierung des Batteriespeichers, optimaler Batteriespeichereinsatz, PV-Einspeisung, PV-Abregelung, Elektromobilität, Niederspannungsnetz, hybride OPF-Methoden.
Acknowledgement

This master thesis was carried out in the Power Systems Laboratory (PSL) at ETH Zürich in cooperation with the grid design department of ewz, the utility of the city of Zurich. Having spent the last six months working on this thesis there are a lot of people I wish to thank:

I would like to express my deepest gratitude to my supervisors Dr. Florian Kienzle from ewz and Evangelos Vrettos from ETH Zürich for their aspiring guidance and encouragement throughout this project. This work could not have been conducted without them. Special thanks goes to my colleague at ewz, Evdokia Kaffe for her invaluable feedback and advice whenever this was needed.

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I would like to express my sincere gratitude to Hansruedi Luternauer for allowing me to conduct this master thesis in ewz and deal with such an exciting and applied topic. My gratitude extends to all my colleagues in the grid design department for their warm welcome to the group.

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<th>Acronym</th>
<th>Description</th>
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<tbody>
<tr>
<td>ACL</td>
<td>Allowable Curtailment Level</td>
</tr>
<tr>
<td>APC</td>
<td>Active Power Curtailment</td>
</tr>
<tr>
<td>DSM</td>
<td>Demand Side Management</td>
</tr>
<tr>
<td>DSO</td>
<td>Distribution System Operator</td>
</tr>
<tr>
<td>ewz</td>
<td>Elektrizitätswerk der Stadt Zürich</td>
</tr>
<tr>
<td>HC</td>
<td>House Connection</td>
</tr>
<tr>
<td>HV</td>
<td>High Voltage</td>
</tr>
<tr>
<td>LV</td>
<td>Low Voltage</td>
</tr>
<tr>
<td>MV</td>
<td>Medium Voltage</td>
</tr>
<tr>
<td>OLTC</td>
<td>On Load Tap Changer</td>
</tr>
<tr>
<td>OPF</td>
<td>Optimum Power Flow</td>
</tr>
<tr>
<td>PF</td>
<td>Power Flow</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaics</td>
</tr>
<tr>
<td>RES</td>
<td>Renewable Energy Sources</td>
</tr>
<tr>
<td>RPC</td>
<td>Reactive Power Control</td>
</tr>
<tr>
<td>SOC</td>
<td>State Of Charge</td>
</tr>
<tr>
<td>TS</td>
<td>Transformer Station</td>
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### Latin letters

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
<th>Description</th>
</tr>
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<tbody>
<tr>
<td>$n_t$</td>
<td>–</td>
<td>Number of time steps</td>
</tr>
<tr>
<td>$n_b$</td>
<td>–</td>
<td>Number of buses</td>
</tr>
<tr>
<td>$n_l$</td>
<td>–</td>
<td>Number of lines</td>
</tr>
<tr>
<td>$n_D$</td>
<td>–</td>
<td>Number of days simulated</td>
</tr>
<tr>
<td>$\mathbb{I}_{grid}$</td>
<td>–</td>
<td>Set including all buses with a connection to an external grid</td>
</tr>
<tr>
<td>$\mathbb{I}_{bat}$</td>
<td>–</td>
<td>Set including all potential battery installation buses apart from the house connection nodes</td>
</tr>
</tbody>
</table>

- $B/b$: Siemens/p.u. Shunt susceptance of line
- $C$: CHF/unit Cost per unit
- $E$: $V^o/Wh$ Complex voltage/Energy (depending on context)
- $f$: - Battery dimensioning ratio
- $G/g$: Siemens/p.u. Conductance of line
- $I$: A Current
- $LT$: years Lifetime
- $P$: W Active power flow
- $Q$: VAr Reactive power flow
- $R/r$: $\Omega$/p.u. Resistance of line
- $S$: VA Apparent power flow
- $SC$: - Scaling factor
- $TC$: CHF Total cost
- $U$: $V$ Voltage magnitude
- $V$: p.u. Voltage magnitude
- $X/x$: $\Omega$/p.u. Reactance of line
- $Y/y$: Siemens/p.u. Complex admittance of line
- $Z/z$: $\Omega$/p.u. Impedance of line
### Greek letters

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>(\eta)</td>
<td>-</td>
<td>Efficiency</td>
</tr>
<tr>
<td>(\xi)</td>
<td>-</td>
<td>Degree of self-sufficiency</td>
</tr>
<tr>
<td>(\theta)</td>
<td>radians</td>
<td>Voltage angle</td>
</tr>
<tr>
<td>(\Phi_k)</td>
<td>-</td>
<td>Set of buses adjacent to (k), including (k)</td>
</tr>
<tr>
<td>(\psi)</td>
<td>-</td>
<td>Self-consumption rate</td>
</tr>
<tr>
<td>(\Omega_k)</td>
<td>-</td>
<td>Set of buses adjacent to (k), excluding (k)</td>
</tr>
</tbody>
</table>

### Subscripts

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
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<tbody>
<tr>
<td>B</td>
<td>Battery</td>
</tr>
<tr>
<td>ch</td>
<td>Charge</td>
</tr>
<tr>
<td>cu</td>
<td>Curtailment</td>
</tr>
<tr>
<td>dis</td>
<td>Discharge</td>
</tr>
<tr>
<td>el</td>
<td>Electricity</td>
</tr>
<tr>
<td>G</td>
<td>Generation</td>
</tr>
<tr>
<td>grid</td>
<td>Related to the MV grid</td>
</tr>
<tr>
<td>inj</td>
<td>Power injected on bus</td>
</tr>
<tr>
<td>(k)</td>
<td>At (^1) bus (k)</td>
</tr>
<tr>
<td>(kk)</td>
<td>Between bus (k) and ground</td>
</tr>
<tr>
<td>(km)</td>
<td>Between (^1) buses (k) and (m)</td>
</tr>
<tr>
<td>L</td>
<td>Load</td>
</tr>
<tr>
<td>losses</td>
<td>Losses</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic</td>
</tr>
<tr>
<td>set</td>
<td>Pre-determined value</td>
</tr>
<tr>
<td>slackbus</td>
<td>At slack bus</td>
</tr>
</tbody>
</table>

\(^1\)For symbols that represent power flows, a single subscript with the bus number indicates power injection, while a double subscript indicates power flow between two buses.
Superscripts

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>*</td>
<td>Complex conjugate</td>
</tr>
<tr>
<td>bat</td>
<td>Use through battery</td>
</tr>
<tr>
<td>direct</td>
<td>Direct use</td>
</tr>
<tr>
<td>max</td>
<td>Maximum value</td>
</tr>
<tr>
<td>min</td>
<td>Minimum value</td>
</tr>
<tr>
<td>ref</td>
<td>Reference value</td>
</tr>
<tr>
<td>sh</td>
<td>Shunt element</td>
</tr>
<tr>
<td>T</td>
<td>Transpose of a matrix</td>
</tr>
<tr>
<td>year</td>
<td>Yearly value</td>
</tr>
</tbody>
</table>

Notation

In this thesis the following notation conventions apply:

- Vectors and matrices are indicated with bold letters.
- When the same quantity is expressed with capital and lower case letters, the capital letters indicate the S.I. values while lower-case letters are used to express p.u. values.
- $R^n$ is used to denote the n-dimensional space of real numbers.
- Most of the variables used in this thesis have both a time and a space dimension. Therefore, the convention of using the time step as a subscript and the node in brackets is here followed. The quantity $P_{B,a,t}(b)$, would hence indicate the battery charge of the bus $b$ at time step $t$. 
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Chapter 1

Introduction

In this chapter the motivation behind the increasing PV penetration in distribution grids as well as the resulting challenges are analyzed from a DSO perspective. Subsequently, the most common potential remedies to mitigate the occurring problems are presented.

1.1 PV penetration in distribution grids and resulting challenges

In Switzerland, the promotion of Renewable Energy Sources (RES) by the federal government has been increasing over the last years. Specifically, the majority of citizens in the city of Zurich voted in 2008 in favor of the implementation of the 2000-Watt society concept, an environmental vision introduced by ETH [1]. The 2000-Watt society concept refers both to the reduction of the overall continuous energy usage to no more than 2000 Watts per person, as well as to the reduction of the carbon footprint to no more than 1 ton CO$_2$ equivalent per person by 2050 [2].

In the study “ewz-Stromzukunft 2012-2050” carried out by ewz, the electric utility of the city of Zurich, the energy future of ewz is put under the spotlight [3]. More specifically, four different scenarios concerning the ewz electricity production mix until 2050 are formulated and investigated from an energy, environmental and financial point of view. In all of them, a strong penetration of Distributed Generation (DG), and especially of wind and PV energy, is expected. In Figure 1.1 the future production mix of the ewz portfolio for scenario 3, the scenario with the biggest expected PV penetration, is depicted. Although the wind power installed capacity refers to wind power plant installations abroad or in other parts of Switzerland, the majority of the PV power plants is expected to be installed within the urban network of Zurich. The challenge for ewz lies on the integration of this increasing renewable share into the existing network without endangering the security and quality of the electricity supply. The study Energiezukunft Schweiz [4], conducted by ETH Zurich, predicts an increase in load demand with a simultaneous decrease in conventional electricity production. The electricity generation gap is expected to be covered by renewable energy resources and their integration is discussed. The
increasing share of RES in the European electricity production mix is also thoroughly investigated in [5], a report conducted for the European Commission. In this report, an in-depth analysis of the subject "Integration of Renewable Energy in Europe" is done.

A very high PV penetration in the low voltage level (LV) can bring challenges for the existing electricity grid infrastructure, possibly leading to the violation of several technical constraints. Distribution systems are no longer merely supplying loads, but are confronted with power flows and voltages determined by the generation to load ratio at each point in time. When the energy produced by photovoltaic panels during solar peak irradiation hours exceeds the locally demanded load, reverse power flows towards the medium voltage network and voltage rises might appear. This can pose new challenges to the electrical power systems, where traditionally only large central plants supplied electricity through the transmission and distribution grid to the end user [6], [7]. The technical constraints that are taken into account in this thesis are briefly presented below.

1.1.1 Voltage violations

The connection of a PV system to the receiving end of a distribution line might result in voltage rises at the connection point, when the generation to load ratio at this node is considerably higher than one [8], [9]. This effect is even more pronounced in underground cables, because of their high capacitance. Until now, such problems appeared only at night when the load is low. The capacitive character of the cables results in voltage rises, a phenomenon known as Ferranti effect [10].
1.1.2 Transformer and line thermal overloading

Reverse power flows may be another effect of high PV penetration in the LV level. If at a specific time, photovoltaic production is higher than the load, power flows from the end customers to the MV/LV transformer station are created. The LV networks have been traditionally designed to deliver power to the loads even under maximum loading conditions. However, when reverse power flows appear, the capability of the transformer and the lines to withstand these potentially increased reverse flows has to be reevaluated. The impact of high PV penetration on a HV/MV transformer loading in Germany is depicted in Figure 1.2. It can be seen that an increase in PV penetration over the years results in high reverse power flows during the summer months.

1.2 PV grid integration measures

In the project “PV Leimbach” initiated by ewz, a complete analysis and comparison of potential PV integration measures is carried out [12]. A similar techno-economic analysis is done in [7], where the corresponding situation in Germany is analyzed from a DSO’s perspective. An important parameter highlighted in this report, is the role of the regulatory framework of the various measures suggested. In [13] seven different methods for the increase of the PV hosting capacity of a distribution grid are studied in a unified simulation approach. A brief analysis of the most common proposed measures in literature follows.

1.2.1 Conventional network expansion

The distribution network reinforcement is the traditional way used by DSOs when a grid has to be expanded due to an expected electric power demand growth. The conventional
network expansion may refer to the replacement or the upgrade of the transformers, construction of new transformer stations, replacement of existing or laying of new cables, redesign of the network’s topology, etc. Distribution expansion planning is a highly complex and computationally demanding optimization problem, that involves a large number of local optimal solutions [14].

In case of a considerable PV penetration in a LV network, all these actions would be taken in order to face the violation of the aforementioned constraints. The increase of a cable’s cross section would relax for example the cable loading constraint and reduce also the voltage rise at the receiving end of the cable. In [14] an optimization problem is formulated to maximize the DG hosting capacity using conventional expansion measures. A method of planning DG integration together with network expansion is suggested in [15], while in [5] increased costs for distribution grid expansion are expected due to a high penetration of RES in the future electricity system.

1.2.2 Reactive power control (RPC)

Reactive power control (RPC) is a common practice of electricity system operators to control the voltage level of the network by regulating the production, absorption and flow of reactive power in the system. In case of voltage rises caused by high PV penetrations, an inductive power factor would be needed in order to address the voltage problem. However, it should be noted that the implementation of RPC would bring increased line flows and consequently increased losses in the grid. Already a lot of inverter production companies have integrated smart control systems in their PV inverters for the mitigation of voltage rises at the connections points [16], [17].

1.2.3 Demand Side Management (DSM)

Demand side management (DSM), also known as demand response or simply load management, refers to the act of balancing the electricity supply and demand by controlling the load rather than the production. In case of PV integration, a technical load increase on the demand side during peak PV infeed hours would lead to the relaxation of the technical constraints. In [18] an aggregation of thermostatically controlled loads is used for the increase of a LV network DG hosting capacity.

1.2.4 On-load tap changers (OLTC)

A MV/LV transformer’s voltage is usually set to values higher than 1 p.u. by the DSO in order to maintain high voltage drop margins during the evening load peaks. However, this strategy results in limited voltage rise margins during the peak PV infeed hours in a distribution grid with a high PV penetration. The installation of an on-load tap changing transformer on the MV/LV level would automatically shift the voltage setpoint according to the grid’s load. In [19], it is shown that a 3% OLTC voltage setting band (0.97 p.u. - 1.03 p.u.) would lead to a double PV hosting capacity in the investigated
network if only voltage constraints are taken into account. An OLTC transformer is nevertheless a measure to deal only with the voltage rise problem. Thus, if line or transformer overloading problems are present, additional measures need to be taken.

1.2.5 Battery storage

Battery storage gains ground among the electric utilities as a PV integration measure, mainly due to the versatile services that it can offer. A battery storage system can relieve the network from both overvoltages and overloadings by peak-shaving during the PV peak infeed hours while at the same time it can boost the self-sufficiency of a household by shifting the stored excess PV energy towards the evening load peak. Already, subsidies that incentivise PV plant owners to install battery storage systems have been introduced in Germany [20]. In Switzerland, a lot of battery projects are currently running. In the pilot project Gridbox, smart cooperation schemes between battery storage, RES, DSM and electric mobility in the distribution grid are investigated [21]. EKZ (Elektrizitätswerke des Kantons Zürichs) and ABB are performing similar investigations using battery of 1 MWh energy capacity, which makes it the biggest in Switzerland [22]. In the simulations performed in [19] a 250% higher PV penetration has been achieved with a battery storage system with energy capacity equivalent to 4 hours of nominal PV production.

1.2.6 Active Power Curtailment (APC)

As high PV infeed occurs only during some limited hours during the year, a potential measure to increase the PV hosting capacity is to simply curtail these peaks. This peak power curtailment would result nevertheless to a reduced PV energy yield. In this thesis, the abbreviation of ACL is used to express the Allowable Curtailment Level. An ACL of 0% means that no curtailment is allowed, while an ACL of 100% indicates that the whole PV infeed can be curtailed. A permanent ACL of 35% would result to a 2.4% energy yield reduction in the case study examined in [12], while in the investigations conducted in [13], a 50% increase in the PV hosting capacity would require 3% PV energy losses due to APC.

An important parameter in the discussion about APC is the regulatory framework in each country. In Germany, PV plants with an installed capacity smaller than 30kW are obliged to be able to limit their production to 70% of their installed capacity (ACL = 30%) if necessary [23]. In Switzerland no defined regulatory framework concerning APC exists yet.
Chapter 2

Problem Definition

In this chapter, the scope of the thesis is first defined. Subsequently, a brief review of work that addresses questions similar to the ones set in this thesis is conducted. Finally the most important research questions of this thesis are listed and the structure of the report is defined.

2.1 Problem description

The installation of battery storage as a PV integration measure is becoming more and more popular among distribution system operators both because of its versatility as a solution as well as due to the fastly dropping battery costs in the market. Battery storage represents a solution that can address both of the technical problems taken into account in this thesis, while at the same time it can boost the self-sufficiency of PV owners.

The goal of this master thesis is to develop a general optimization tool for the assessment of the optimal placement and sizing of such a battery storage system in a real distribution grid. The objective function of the optimization problem will include only the battery installation costs so that a direct cost comparison with other PV integration measures can be conducted.

On a second step, the optimal dispatch of the predetermined battery storage system by the main optimization problem can be assessed with an objective of maximizing the self-sufficiency of the LV network. Therefore two separate optimization problems are formulated:

- Optimal battery placement and sizing
- Optimal battery dispatch

Unlike classical Optimal Power Flow (OPF) that produces a snapshot of the system’s power flows, the implementation of battery storage necessitates a correlation across the time horizon of the optimization problem. Therefore, typical or worst-case (in terms of
constraints violation) days have to be investigated in a multi-period OPF. The size of actual LV grids in conjunction with the complexity of a multi-period battery allocation problem renders the optimization problem computationally-hard. Thus, novel, hybrid OPF methods have to be introduced to make the optimization problem tractable. The three fundamental requirements that an optimization tool for real-scale networks should fulfill are:

- Reasonable computational time
- Sufficiently accurate results
- Ability to handle many different operating constraints

The assessment of the role of APC and electric mobility in the integration of PV is another important aspect for grid operators. Unlike the battery storage multi-period OPF problem, where one single day suffices to take into account the charge-discharge cycle, in case of APC, a longer period needs to be simulated in order to take into account seasonal differences. The inherent difference between a battery storage system and APC lies in the calculation of the resulting costs. A battery storage system would require only installation costs and no operational costs, while on the other hand only operational costs for the PV owners remuneration would be incurred in the case of APC. Therefore, although the examination of the worst-case day in terms of constraint violations would be enough for battery dimensioning, many characteristic days throughout the year should be selected to faithfully assess the role of APC as a PV integration measure and calculate its resulting costs.

2.2 Related work

Battery storage as a way to increase the PV hosting capacity of a system is gaining interest recently both in academia and among DSOs. In [24], the optimum siting and sizing of a battery system with a predetermined total installed capacity is investigated. The complexity of the problem is here addressed with a two stage iterative procedure along with the adoption of heuristics. Specifically, a genetic algorithm produces the locations and sizes of the battery storage system, while a daily AC OPF evaluates the fitness of these solutions in order to minimize the total operating cost. A similar approach is followed in [25], where the sum of the costs sustained by the DSO for power losses, for network upgrading, for carrying out the reactive power service as well as the costs for storage and capacitor installation are taken into account.

In [26], the authors suggest a multiobjective placement algorithm of predetermined sized batteries assuming three different components in the objective function: voltage regulation, peak power reduction and annual cost. In this case, approximations have been used to make the optimization problem tractable, such as the linearization of the power flow equations. An integrated analysis of storage systems together with conventional
network expansion is provided in [27]. In this work, a pre-selection of the potential battery installation nodes is done.

However, the above-mentioned algorithms have been either applied only to small, usually radial networks, or predetermined sizes and/or locations for the battery storage system are assumed. The implementation of non-linear optimum battery storage sizing and placement algorithms in an actual-size network requires a big amount of computational effort, while sometimes the problem might be computationally untractable. Therefore, a novel approach to solve the optimal battery placement and sizing problem for real distribution networks in acceptable computational times is needed.

2.3 Research objectives

The central research question of this thesis is:

“Which is the cost-optimal placement and sizing of a battery storage system to integrate the full PV potential of a LV grid without any technical constraints violation?”

Additionally, potential synergies between PV generation, battery storage, APC and electric mobility are also studied in the context of this work. Specifically, the objectives of this thesis can be summarized as:

• Examine the results of PV penetration in a real distribution network.
• Evaluate the suitability of existing OPF algorithms to solve real scale multi-period non-linear optimization problems.
• Develop a versatile optimization tool to determine the optimal sizing and placement of a battery storage system as a PV integration measure.
• Assess the optimal battery dispatch at a second step, using the optimized battery sizes and locations from the first optimization.
• Integrate APC and electromobility schemes into the developed tool.
• Implement the optimization methods on a real distribution grid and evaluate the results.

2.4 Outline of the thesis

The rest of the report is structured as follows:

Chapter 3: Optimization Methods. The theoretical background on optimal power flow along with the existing OPF methods is discussed in this chapter. Next, the hybrid
OPF methods that are used in this thesis are presented and the constraints as well as the objective function for each method are defined.

Chapter 4: Simulation Model and Data. This chapter contains the description of the modelling framework used in this thesis. Information about the data used for the assessment of the load, PV and electromobility profile is also provided.

Chapter 5: Simulations. In this chapter the results of the optimization tool on a real case-study network are presented. First the functionality as well as the performance of the examined methods is investigated for a benchmark network of reduced size in order to choose the most suitable method for implementation in realistic size networks. Subsequently, the optimal placement and dispatch of a battery storage system in a real-scale network is assessed for different operating scenarios. Finally three different sensitivity analyses with varying problem parameters is carried out and their results are discussed.

Chapter 5: Conclusion. The main conclusions of the work presented in this thesis are discussed in this chapter.

Chapter 5: Outlook. Ideas for potential further research on the subject are listed here.
Chapter 3

Optimization Methods

In the first part of this chapter the theoretical background of the methods used in this thesis is discussed. Specifically, the basic principles behind AC OPF and DC OPF are given. Subsequently, the hybrid OPF methods suggested in this thesis are presented. The last section of this chapter deals with the optimization problem formulation.

3.1 Optimal power flow

In this section a brief overview of the most important equations and concepts of the power flow problem that are used in the formulation of the optimization problem are presented. First, the model used along with the principles of AC OPF are described, while the approximations that lead to the DC OPF problem are discussed in the second subsection.

A Power Flow (PF) study is a numerical analysis of the flow of electric power in an interconnected system to calculate the voltages and currents in different parts of the system. A power flow analysis is a complex computational problem due to its inherent nonlinearities but it constitutes at the same time a very essential tool for the design of a secure and reliable power system [28], [29].

The Optimal Power Flow (OPF) refers to a PF aiming at the minimization of a value, such as the generation cost or the total ohmic losses. The application of such a minimization objective identifies power inputs and bus voltages to achieve the minimum cost [30].

3.1.1 AC Optimal power flow

Line model

The following derivation is mainly based on [28]. In Figure 3.1, the basic network model that is used for the PF calculations is presented. The nodes $k$ and $m$ represent two adjacent nodes of the network. The series parameters that characterize the distributed
model are given below. The capital letters indicate that the quantity is expressed in
ohms or siemens, while lower case letters are used to express p.u. values.

\[ R = \text{series resistance (Ω)} \]
\[ X = \text{series reactance (Ω)} \]

and the shunt parameters:

\[ B = \text{shunt susceptance (siemens)} \]
\[ G = \text{shunt conductance (siemens)} \]

These parameters depend on the line or cable configuration and are dependent on conductors materials and geometrical arrangements. The complex parameters that characterize the π-model of Figure 3.1 are:

\[ Z_{km} = R_{km} + jX_{km} = \text{series impedance (Ω)} \quad (3.1) \]
\[ Y_{sh}^{km} = G_{sh}^{km} + jB_{sh}^{km} = \text{shunt admittance (siemens)} \quad (3.2) \]

The derivation of the parameters depicted in Figure 3.1 is given below. The formulation of the PF network equations requires the creation of the node admittance matrix and hence the series admittance of the line model is needed.

\[ y_{km} = z_{km}^{-1} = g_{km} + jb_{km} \quad (3.3) \]

where

\[ g_{km} = \frac{r_{km}}{r_{km}^2 + x_{km}^2} \quad (3.4) \]
CHAPTER 3. OPTIMIZATION METHODS

and

\[ b_{km} = -\frac{x_{km}}{r_{km}^2 + x_{km}^2} \] (3.5)

Usually, the value of \( g_{km} \) is so small that it can be neglected, which is the case in this thesis.

**Active and reactive power flows**

The complex currents \( I_{km} \) and \( I_{mk} \) between the nodes \( k \) and \( m \) in Figure 3.1 can be expressed as functions of the complex voltages at the branch terminal nodes \( k \) and \( m \):

\[
I_{km} = y_{km} (E_k - E_m) + j b_{km}^s E_k \quad (3.6)
\]

\[
I_{mk} = y_{km} (E_m - E_k) + j b_{km}^s E_m \quad (3.7)
\]

where the complex voltages are:

\[
E_k = U_k e^{j\theta_k} \quad (3.8)
\]

\[
E_m = U_m e^{j\theta_m} \quad (3.9)
\]

The complex power flow between the nodes \( k \) and \( m \), \( S_{km} = P_{km} + j Q_{km} \) is given by the equation:

\[
S_{km} = E_k I_{km}^* = y_{km} U_k e^{j\theta_k} (U_k e^{-j\theta_k} - U_m e^{j\theta_m}) - j b_{km}^s U_k^2 \quad (3.10)
\]

By identifying the real and imaginary parts of eq. 3.10, the expressions for the active \( P_{km} \) and reactive \( Q_{km} \) power flow can be determined. These equations are used in the algorithms for the calculation of the active and reactive power flows between two nodes.

\[
P_{km} = U_k^2 g_{km} - U_k U_m g_{km} \cos \theta_{km} - U_k U_m b_{km} \sin \theta_{km} \quad (3.11)
\]

\[
Q_{km} = -U_k^2 (b_{km} + b_{km}^s) + U_k U_m b_{km} \cos \theta_{km} - U_k U_m g_{km} \sin \theta_{km} \quad (3.12)
\]

where \( \theta_{km} = \theta_k - \theta_m \), the angle difference between the two nodes.

The active and reactive power flows in opposite directions can be obtained in the same way:

\[
P_{mk} = U_m^2 g_{km} - U_k U_m g_{km} \cos \theta_{mk} - U_k U_m b_{km} \sin \theta_{mk} \quad (3.13)
\]

\[
Q_{mk} = -U_m^2 (b_{km} + b_{km}^s) + U_k U_m b_{km} \cos \theta_{mk} - U_k U_m g_{km} \sin \theta_{mk} \quad (3.14)
\]
Nodal form of the network equations

For the formulation of an AC OPF problem apart from the power flows between nodes, the net power injections per node is also needed. In Figure 3.2 the basic nodal model is shown. The power balance for the node depicted in Figure 3.2, yields

$$I_k + I_k^{sh} = \sum_{m \in \Omega_k} I_{km}, \text{ for } k = 1, \ldots, n_b \quad (3.15)$$

where $k$ is a generic node, $I_k$ is the net current injection from generators and loads, $I_k^{sh}$ is the current injection from shunts, $m$ is a node adjacent to $k$, $\Omega_k$ is the set of nodes adjacent to $k$ and $n_b$ is the number of nodes in the network.

Equation 3.15 together with 3.6 and the nodal admittance matrix $Y = G + jB$, result in the current injection equation per node:

$$I_k = Y_{kk}E_k + \sum_{m \in \Omega_k} Y_{km}E_m = \sum_{m \in \Phi_k} Y_{km}E_m \quad (3.16)$$

where $\Phi_k$ is the set of buses adjacent to bus $k$ (including bus $k$) and $\Omega_k$ is the set of buses adjacent to bus $k$, excluding bus $k$. Now considering that $Y_{km} = G_{km} + jB_{km}$ along with eq. 3.9, eq. 4.1 can be rewritten as:

$$I_k = \sum_{m \in \Phi_k} (G_{km} + jB_{km})(U_me^{j\theta_m}) \quad (3.17)$$

The complex power injection at bus $k$ is

$$S_k = P_k + jQ_k = E_kI_k^* \quad (3.18)$$
and by applying eq. 3.17 this gives

\[ S_k = U_k e^{j\theta_k} \sum_{m \in \Phi_k} (G_{km} + jB_{km})(U_m e^{j\theta_m}) \]  

(3.19)

If the real and imaginary parts of eq.3.19 are taken, the expressions for active and reactive power injections that are used in the OPF algorithm are obtained:

\[ P_k = U_k \sum_{m \in \Phi_k} U_m (G_{km}\cos\theta_{km} + B_{km}\sin\theta_{km}) \]  

(3.20)

\[ Q_k = U_k \sum_{m \in \Phi_k} U_m (G_{km}\sin\theta_{km} + B_{km}\cos\theta_{km}) \]  

(3.21)

All these equations consist a non-linear problem and numerical techniques with iterative approaches are needed to solve the PF problem. The two main algorithms used for this purpose are the Gauss-Seidel iterative method and the Newton-Raphson method. Due to the inefficiency and the slow convergence of the Gauss-Seidel method in some cases, the Newton-Raphson method is preferred and widely used for power flow analysis problems.

The PF problem described above, is also called a feasibility problem, since the objective is to find any solution at all without regard to an objective value. On the other hand, in an OPF problem, the algorithm is looking for a solution that minimizes a pre-defined objective function. Typical objective functions used in OPF problems are the total generation costs or the total line losses. An optimal power flow calculation is a non-convex problem, which in combination with the non-linear character of a simple PF problem results in additional computational challenges. One of the most popular methods to solve non-linear and non-convex OPF problems is the interior point method.

A typical AC OPF problem involves four decision variables for each network node \( k \):

- \( U_k \), the voltage magnitude
- \( \theta_k \), the voltage angle
- \( P_k \), the real power injection
- \( Q_k \), the reactive power injection

In this thesis, due to the multi-period time dimension introduced by the battery storage, 24 consecutive and coupled optimal power flows are needed to simulate the daily charge-discharge battery cycle. In Figure 3.3, the basic block of AC OPF is shown. The block “Multi-period AC OPF” corresponds to one single AC OPF with one objective function coupling multiple time steps throughout one or more days. This differs from multiple single consecutive AC OPFs, since the coupling of the objective function and the battery constraints are increasing the complexity of the problem. This block is later used in Section 3.2 as a component of the hybrid OPF methods.
3.1.2 DC Optimal power flow

Sometimes during the operation of electric power systems fast and frequent solutions to the PF problem are needed. The exact expressions of the PF equations that were formulated in section 3.1.1 lead to a non-linear problem which is difficult and slow to be solved. Therefore, certain approximations to the exact equations have been introduced. These approximations lead to a linear problem that can be used when fast results are needed or to identify the critical cases, which then can be solved with the full AC PF equations. A brief derivation of the simplified equations used in the DC PF model is here provided [28].

Line resistance simplification

If eqs. 3.11 and 3.13 are added, the real power losses of the line connecting the nodes $k$ and $m$ can be calculated:

$$P_{losses} = P_{km} + P_{mk} = g_{km}(U_k^2 + U_m^2 - 2U_kU_m\cos\theta_{km})$$  \hspace{1cm} (3.22)

Usually, the line conductance $g_{km}$ is much smaller than the line susceptance $b_{km}$ and can be neglected in most of the cases.

$$g_{km} = 0$$  \hspace{1cm} (3.23)

If the line conductance $g_{km}$ and hence the real power losses are not taken into account, the resulting power flows are:

$$P_{km} = -P_{mk} = -U_kU_mb_{km}\sin\theta_{km}$$  \hspace{1cm} (3.24)

$$Q_{km} = -U_k^2(b_{km} + b_{km}^{th}) + U_kU_m b_{km}\cos\theta_{km}$$  \hspace{1cm} (3.25)

$$Q_{mk} = -U_m^2(b_{km} + b_{km}^{th}) + U_kU_m b_{km}\cos\theta_{km}$$  \hspace{1cm} (3.26)

Voltage simplification

An additional simplification that can be made to linearize the problem is to disregard the
voltage magnitudes from the PF calculations. Usually, the voltage band of the network nodes is small and close to 1p.u. In such cases a value of 1p.u. can be assumed for all the network buses.

\[ U_k \approx U_m \approx 1 \text{p.u.} \quad (3.27) \]

For light load conditions, the voltage angles are taking small values and hence it can be assumed:

\[ \sin \theta_{km} \approx \theta_{km} \quad (3.28) \]

Taking into account the simplifications described in eqs. 3.23, 3.27, 3.28 the resulting power flow equations are:

\[ P_{km} = -P_{mk} = \theta_{km}b_{km} \quad (3.29) \]
\[ Q_{km} = Q_{mk} = 0 \quad (3.30) \]

The decision variables taken into account in a DC OPF problem are:

- \( \theta_k \), the voltage angle
- \( P_k \), the real power injection

It is clear, that voltage magnitudes and reactive power flows are not taken into account with these approximations. The multi-period DC OPF basic block is shown in Figure 3.4

### 3.2 Hybrid OPF methods

In this thesis a versatile optimization tool for real-scale distribution networks is suggested. The nature of the battery sizing and placement problem not only introduces an optimization algorithm with a lot of nonlinearities but also requires many optimization variables due to the multi-period character of the problem. Thus, although the implementation of a full multi-period AC OPF to solve the problem described in Section 2.1 gives results in reasonable times for small test networks, the application on a real-scale
network might be very difficult, or require immense computational power.

On the other hand, the multi-period DC OPF problem is tractable even for big networks and for the coupling of many periods. However, the results of the DC OPF algorithm lack information about the voltage profile of the network as well as about the reactive power flows. Depending on the situation, this information could be crucial for the DSO. As described in Sections 1.1.1 and 1.1.2, the voltage profile and the thermal loading of the network components constitute the two technical constraints that have to be attended by the optimization algorithm in the context of this thesis. Therefore, the ability of the algorithm to take into account the voltage magnitude at network’s nodes is of great importance. In this section, two different hybrid approaches are presented in an attempt to balance the trade-off between the AC and DC OPFs with a fast algorithm that doesn’t lack crucial network information.

3.2.1 Method a: nested AC constraints

Although the voltage profile of the network is of interest, it is only the voltage limit violation hours that have an effect on the battery placement and sizing. In Figure 3.5 the flow chart of Method a is depicted. The identification of the problematic hours in terms of voltage violations is done a priori with a series of simple AC power flows, one for each time step. The computation time needed for a simple AC PF is very small, since no optimization has to be performed and no coupling between consecutive time steps is present. In this way, the problematic hours in terms of voltage violations can be identified and used as an input to the main multi-period AC OPF algorithm. Subsequently, a single AC-DC hybrid multi-period OPF problem is formulated with the following characteristics:

- AC equations for the voltage problem hours.
- DC equations for the rest of the hours.

The use of this method would satisfy the goals set in Chapter 2.1 since no crucial network information is neglected, while the computational time is kept as low as possible by expressing the non-critical for constraint violation time periods with simplified DC equations. It is clear that the computational time needed by Method a, depends directly on the voltage profile of the network before the battery storage installation. Therefore,
in a case that voltage problems are identified for the most of the time steps investigated, the computation time reduction is limited. On the other hand, it could be that the preliminary AC PF test will not identify any critical voltage hours and the whole Method a formulation will formulate a simple multi-period DC OPF (Figure 3.4).

3.2.2 Method b: iterative condition-based approach

The improvement that Method a brings to the computational time depends mainly on the number of voltage problem hours that have been identified. Thus, in a problematic network in terms of voltage violations, a significant number of non-linear constraints still remains in the optimization formulation, delaying or even preventing the algorithm’s convergence.

In light of this, another method that is based only on a multi-period DC OPF as its main block function is here proposed. The flowchart of Method b is given in Figure 3.6. An external iterative procedure ensures that the voltage profile is considered with the help of a voltage violation controller. If voltage violations are identified, the battery allocation is adjusted accordingly, in order to address those violations. The flowchart is explained in more detail below:

1. A multi-period DC OPF is performed.
2. The resulting battery dispatches are simulated as additional load / generation in order to be used as an input to the AC PF block.
3. \( n \) consecutive AC PF calculations are run in order to assess the voltage profile for each time step. The battery dispatches that resulted from step 1 are taken into account as additional load at the corresponding nodes.
4. The voltage problematic hours and nodes are identified by the voltage violation controller.
5. In case that no voltage problems have been identified, the solution is accepted as sub-optimal and the iterative procedure is terminated. Otherwise, an additional constraint is given as an input to the multi-period DC OPF. This extra constraint forces the battery charge of the problematic nodes during the problematic hours to be greater than a predetermined value. This value is increased by a small power increment (e.g. 1kW) for each iteration. The exact mathematical formulation of the additional constraints used in Method b is given in Section 3.3.1.
6. Go to Step 1 if voltage violations still exist.

The incremental increase of the problematic nodes battery charge will eventually lead to the limitation of the voltage rises below the values dictated by the technical regulations. Naturally, by implementing such an approach, a sub-optimal solution is obtained. The convergence speed of Method b depends on the severity of the voltage problems as well.
as on the power increment value chosen. A big increment value would lead to fast convergence times but the solutions would be further from the optimum than with small power increments.

In the Section 5.2.5, the performance, the time efficiency and the quality of the results of the proposed hybrid methods is tested and evaluated in comparison to the AC OPF and DC OPF methods.

### 3.3 Optimization problem formulation

The mathematical formulation of the constraints and the objective function taken into account for each method is presented in this section. Additionally, the optimization software packages that have been used are briefly mentioned.

#### 3.3.1 Optimization constraints

The four different methods necessitate different constraints for their implementation and as a result not all of the constraints are applicable to all of the methods. An indication next to each constraint concerning the methods that the constraint applies to, will be given in brackets.
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The number of time steps investigated is denoted with $n_t$, while the number of buses and lines in the network are represented with $n_b$ and $n_l$ respectively. The number of days simulated is expressed by $n_D$ while the notation $I_{\text{grid}}$ indicates the set of all nodes with a connection to an external grid, such as the primary of a transformer station. The set of the potential battery installation nodes apart from the house connections is expressed with $I_{\text{bat}}$. Such nodes could be the transformer station or power distribution cabinets.

1. Slack bus constraints

The slack bus refers to the reference bus of the system where the voltage magnitude and angle are usually set. In our algorithm, the slack bus is chosen to be the secondary of the transformer, while the primary of the transformer is modeled as a virtual generator that simulates the connection to the MV grid. The limits to the allowed power exchange between the modeled LV grid and the upper level are set with Eqs. 3.33, 3.34.

The voltage angle and magnitude are usually set to $0^\circ$ and 1 p.u. respectively. However, more precise voltage setpoints that also take the effect of the MV grid into account are needed in order to obtain a realistic network voltage profile. Therefore, in this thesis the voltage setpoints refer to the voltage of the transformer station’s secondary, acquired by a preliminary PF investigation in which the effect of the MV grid is also considered (Eq. 3.32).

On the other hand, constraint 3.31 is disregarded since the voltage angles are very small and they don’t have any effect on the assessment of the optimal battery sizing and placement. Thus, an additional degree of freedom in the optimization process is added, accelerating the convergence of the algorithm.

- The slack bus voltage angle is set to zero (all methods):
  $$\theta_{\text{slackbus},t} = 0, \forall t \in [1..n_t]$$  
  (3.31)

- The slack bus voltage magnitude is set to a predetermined value (AC OPF, problematic hours of Method a):
  $$V_{\text{slackbus},t} = V_{\text{set},t}, \forall t \in [1..n_t]$$  
  (3.32)

- Active power grid import and export limits (all methods):
  $$-P_{\text{grid}}^{\text{max}} \leq P_{G,t} \leq P_{\text{grid}}^{\text{max}}, \forall t \in [1..n_t]$$  
  (3.33)

- Reactive power grid import and export limits (all methods):
  $$-Q_{\text{grid}}^{\text{max}} \leq Q_{G,t} \leq Q_{\text{grid}}^{\text{max}}, \forall t \in [1..n_t]$$  
  (3.34)
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where $\theta_{\text{slack bus},t}$ and $V_{\text{slack bus},t}$ are the voltage angle and magnitude at the slack bus respectively; $P_{G,t} \in I_{\text{grid}}$ and $Q_{G,t} \in I_{\text{grid}}$ are the active and reactive power generations at the slack bus respectively; $P_{\max_{\text{grid}}}$ and $Q_{\max_{\text{grid}}}$ are the network export/import active and reactive power limit vectors respectively. In this thesis, only one connection to an external grid is assumed at the MV/LV substation. Large enough values that don’t affect the solution are used: $P_{\max_{\text{grid}}}$ = 5 MW and $Q_{\max_{\text{grid}}}$ = 5 MVar.

2. Node power balance constraints

These equations ensure the power balance at each node. In this thesis, the PV plant power factor is assumed to be 1, thus no reactive PV production exists. The same applies to the batteries that are modeled only with active power capability. Therefore, the only node where reactive power can be virtually produced, is the primary of the transformer, where the examined grid is connected to the upper grid level and power imports are enabled.

- Active power balance equation for every node (all methods):
  \[ P_{\text{inj},t} = P_{G,t} - P_{L,t} + P_{\text{ch},t} - P_{\text{dis},t}, \forall t \in [1..n_t] \]  
  (3.35)

- Reactive power balance equation for every node (all methods):
  \[ Q_{\text{inj},t} = Q_{G,t} - Q_{L,t}, \forall t \in [1..n_t] \]  
  (3.36)

where $P_{\text{inj},t} \in R^{n_b}$ and $Q_{\text{inj},t} \in R^{n_b}$ are the active and reactive power injection vectors respectively; $P_{G,t} \in R^{n_b}$ and $Q_{G,t} \in R^{n_b}$ are the generation active and reactive power vectors respectively; $P_{L,t} \in R^{n_b}$ and $Q_{L,t} \in R^{n_b}$ are the uncontrollable active and reactive power demand vectors respectively and $P_{\text{ch},t} \in R^{n_b}$ and $P_{\text{dis},t} \in R^{n_b}$ are the battery storage system charge and discharge power vector respectively.

3. Voltage constraints

The evaluation of the network’s voltage profile is done in this thesis according to the European Norm EN 50160 [31]. This standard specifies an allowed band of ±10% around the nominal voltage $U_n = 400_{ph-ph}$ for a LV network.

- Voltage rise and voltage drop limits for every node (AC OPF, problematic hours of Method a):
  \[ V_{\text{min}} \leq V_t \leq V_{\text{max}}, \forall t \in [1..n_t] \]  
  (3.37)

where $V_t \in R^{n_b}$ is the voltage magnitude vector. The values $V_{\text{min}} = 0.9 \cdot 1^T \text{p.u.}$ and $V_{\text{max}} = 1.1 \cdot 1^T \text{p.u.}$ are used in this thesis.
4. Thermal constraints

The line and transformer thermal limits belong to this category. In the simulations carried out in the context of this thesis, the line loading limit corresponds to the triggering current of the line protection (e.g. circuit breakers) and not to the thermal limit of the material, which is considerably lower. This derives from the fact that a line element can withstand minor thermal overloading for long time periods without any problem. The transformer is simulated as a line segment connecting the primary and the secondary nodes. Its loading limit refers to its nominal capacity (e.g. 630kVA).

- Power flow limits between two adjacent nodes when reactive power is taken into account (AC OPF, problematic hours of Method a):

\[
P_{km,t}^2 + Q_{km,t}^2 \leq S_{km}^{\text{max}}^2, \quad \forall t \in [1..n_t]
\]  

(3.38)

- Power flow limits between two adjacent nodes when reactive power is disregarded (DC OPF, non-problematic hours of Method a, Method b):

\[
-S_{km}^{\text{max}} \leq P_{km,t} \leq S_{km}^{\text{max}}, \quad \forall t \in [1..n_t]
\]  

(3.39)

where \(P_{km,t} \in R^{n_t}, Q_{km,t} \in R^{n_t}\) and \(S_{km,t} \in R^{n_t}\) are the active, reactive and apparent power flow vector respectively. The loading limit vector \(S_{km}^{\text{max}} \in R^{n_t}\) is determined by the line and transformer properties.

5. Generation constraints

The PV production constraints are described in this category. An upper and a lower PV production limit is defined. If the exploitation of the full PV potential of the area is desired, the two-sided inequality constraint would formulate an equality constraint, since the upper and the lower PV production limits would concur. In other words, the PV plants would have to produce their full power at any time, since the upper production limit corresponds to their maximum possible energy yield at time \(t\). However, in case that PV curtailment is allowed, the lower PV production limit differs from the higher one. In this case, the lower allowable PV production would depend on the maximum APC level permitted in the system. In any case, the goal of the DSO is to maximize the PV yield without any technical constraint violation. The PV plants have been modelled with a power factor of 1, hence they have no reactive power generation capabilities.

- Limits on active power generation (all methods):

\[
P_{G,t}^{\text{min}} \leq P_{G,t} \leq P_{G,t}^{\text{max}}, \quad \forall t \in [1..n_t]
\]  

(3.40)
• Limits on reactive power generation (all methods):

\[
Q_{G,t}^{\min} \leq Q_{G,t} \leq Q_{G,t}^{\max}, \quad \forall t \in [1 \ldots n_t]
\]  

where \( P_{G,t} \in (R^{n_b \setminus I_{grid}}) \) and \( Q_{G,t} \in (R^{n_b \setminus I_{grid}}) \) are the active and reactive power production vectors respectively. The limits \( P_{G,t}^{\max} \in (R^{n_b \setminus I_{grid}}) \), \( P_{G,t}^{\min} \in (R^{n_b \setminus I_{grid}}) \), \( Q_{G,t}^{\max} \in (R^{n_b \setminus I_{grid}}) \) and \( Q_{G,t}^{\min} \in (R^{n_b \setminus I_{grid}}) \) refer to the upper and lower active and reactive generation limit and are defined according to the operation mode.

6. Battery constraints

The operation of the battery system is described by the constraints presented below. All the nodes with PV plants installed as well as the secondary of the transformer are considered as potential battery installation locations. An upper limit dependent on the PV installed capacity of each node constrains the corresponding maximum potential battery installed capacity. A value equal to four times the installed PV capacity of each node is chosen (Eq.3.42). This ratio \( f = \frac{E_{inst,B}}{P_{PV}^{\max}} = 4 \) has also been used in an ewz battery storage pilot project in Dora-Staudinger-Strasse [32]. Respectively, the maximum installed capacity of the transformer’s battery is defined based on the available physical space at the transformer station’s location (Eq.3.43). No battery is allowed to be installed at the rest of the network nodes.

• Limits on installed battery capacity of a PV node (all methods):

\[
0 \leq E_{B}^{\text{inst}} \leq fP_{PV}^{\max}
\]  

• Limits on installed battery capacity of other nodes (e.g. transformer’s secondary) (all methods):

\[
0 \leq E_{B}^{\text{inst}}(c) \leq E_{B}^{\text{inst,max}}(c), \quad \forall c \in I_{bat}
\]  

where \( E_{B}^{\text{inst}} \in R^{n_b} \) is the battery installed capacity vector; \( P_{PV}^{\max} \in R^{n_b} \) is the installed PV capacity vector and \( E_{B}^{\text{inst,max}} \in I_{bat} \) is the maximum allowable battery installed capacity at the non-PV nodes.

Generally, deep discharges of a battery storage system accelerate the battery’s ageing process and decrease its lifetime [33]. Frequent battery charges up to 100% should also be avoided [34]. In this thesis the battery state of charge (SOC) lower and upper limits are set to 10% and 90% of its installed capacity respectively (Eq.3.44).
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- Battery SOC upper and lower limits at the potential battery nodes (all methods):

\[ E_{B_{\text{inst}}}^\text{min} \leq E_{B_t} \leq E_{B_{\text{inst}}}^\text{max}, \quad \forall t \in [1..n_t] \quad (3.44) \]

where \( E_{B_t} \in \mathbb{R}^{n_b} \) is the battery SOC vector; \( E_{B_{\text{min}}}^\text{inst} \in [0, 1] \) and \( E_{B_{\text{max}}}^\text{inst} \in [0, 1] \) are the battery SOC minimum and maximum limits. In this thesis, \( E_{B_{\text{min}}}^\text{inst} = 0.1 \) and \( E_{B_{\text{max}}}^\text{inst} = 0.9 \).

Both charge and discharge power assume positive values (Eqs. 3.45, 3.46). The battery charging capacity will be determined by the algorithm itself, hence no upper charging limits are set. The simultaneous charging and discharging of the same battery is prevented by the constraint 3.47. Due to numerical reasons, the formulation \( P_{B_{\text{ch}},t} \circ P_{B_{\text{dis}},t} = 0 \), where the symbol \( \circ \) denotes an element-wise multiplication between the 2 matrices, is avoided since it results in very high solution times. Therefore, a two-sided inequality constraint, with the lower and upper limit set to zero and a very small number \( a \) respectively, is applied instead. The number \( a \) depends on the desired accuracy as well as on the units used for \( P_{B_{\text{ch}}} \) and \( P_{B_{\text{dis}}} \). In this work, the battery charges and discharges are expressed in MW and hence a value of \( a = 10^{-7} \) is chosen.

- Battery charge has to be greater than zero for all battery nodes (all methods):

\[ P_{B_{\text{ch}},t} \geq 0, \quad \forall t \in [1..n_t] \quad (3.45) \]

- Battery discharge has to be greater than zero for all battery nodes (all methods):

\[ P_{B_{\text{dis}},t} \geq 0, \quad \forall t \in [1..n_t] \quad (3.46) \]

- No concurrent battery charge and discharge is allowed (all methods):

\[ 0 \leq P_{B_{\text{ch}},t} \circ P_{B_{\text{dis}},t} \leq a, \quad \forall t \in [1..n_t] \quad (3.47) \]

where \( P_{B_{\text{ch}},t} \in \mathbb{R}^{n_b} \) and \( P_{B_{\text{dis}},t} \in \mathbb{R}^{n_b} \) are the battery charge and discharge vectors respectively. The value \( a = 10^{-7} \cdot 1^T \text{p.u.} \) is used in this thesis.

The introduction of a battery charge/discharge efficiency incentivizes the algorithm to charge and discharge different batteries at the same time step in order to reduce the total required battery installed capacity of the network. In this way, energy produced by the PVs is virtually “dumped” during the battery charge/discharge cycle, which does not align with the DSO requirements for full utilization of the PV potential. Although the concurrent charge and discharge of the same battery is prevented by constraint 3.47, no measure has been taken to avoid of simultaneous charge and discharge of different batteries during the PV infeed hours.
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In this thesis, the set of inequality constraints 3.48, 3.49 is suggested to prevent this phenomenon. In other words, the quantity \( P_{L,t}(b) - P_{G,t}(b) \) is treated as a pseudo-binary variable that determines the batteries operation mode. If the load is higher than the PV production at time \( t \), the batteries are not allowed to charge (constraint 3.48), while in case of PV infeed surplus, the battery discharge is prevented (constraint 3.48). In case that this pair of constraints is introduced, 3.47 is redundant since the concurrent charging and discharging is anyway prevented. Furthermore, the replacement of this constraint with the pair 3.48, 3.49 leads to better computational times by almost 50%, since the multiplication of two decision variables in the same constraint results in strong nonlinearities in the optimization algorithm. In the simulations carried out in this thesis, the formulation 3.48, 3.49 is used.

- No battery discharge is allowed during the PV infeed surplus hours (all methods):
  \[
  P_{\text{dis},t}(P_{L,t}(b) - P_{G,t}(b)) \leq 0, \quad \forall t \in [1..n_t]
  \]  
  (3.48)

- No battery charge is allowed during the PV infeed deficit hours (all methods):
  \[
  P_{\text{ch},t}(P_{L,t}(b) - P_{G,t}(b)) \geq 0, \quad \forall t \in [1..n_t]
  \]  
  (3.49)

where \( b \) is a random network node with installed PV capacity.

In this thesis, an optimization time step of 1 hour is used. A discharge of the battery down to the minimum allowed SOC at the end of each day is assumed. Hour 7 (07:00 am), is considered as the first time step for each day investigated since it is usually the first hour with PV infeed. Therefore, if more than one days are considered, all batteries have to be at their minimum SOC by 06:00am. In this way, the battery SOC of different days can be decoupled and the investigation of different, non-consecutive days of the year is enabled. The reason for the shift of the first hour investigated from 01:00am to 07:00am is to allow bigger margins for the battery discharge. All the above are summarized in constraints 3.50, 3.51.

- Battery’s SOC is set to the minimum allowed SOC at the time step \( t = 1 \) for all battery nodes (all methods):
  \[
  E_{B,1} = E_{B}^{\min} E_{\text{inst}}^B
  \]  
  (3.50)

- Battery’s SOC is set to the minimum allowed SOC at the last time step of each day investigated for all battery nodes (all methods):
  \[
  E_{B,24i} = E_{B}^{\min} E_{B}^\text{inst}, \quad \forall i \in [1..n_D]
  \]  
  (3.51)

The battery storage dynamics are described by constraint 3.52. A battery charge/ discharge efficiency \( n_B \) is included in the formulation.
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- Battery’s SOC at time step \( t \) for all battery nodes (all methods):

\[
E_{B,t} = E_{B,t-1} + \eta_B P_{B_{ch},t} - \frac{P_{B_{dis},t}}{\eta_B}, \forall t \in [2..n_t] \tag{3.52}
\]

where \( \eta_B \) is the battery charge / discharge efficiency. In this thesis, the value \( \eta_B = 0.95 \) is chosen.

7. Method \( b \) constraints

The additional constraints implemented in Method \( b \), refer to the actions that have to be taken in case the voltage violation controller identifies a violation (Figure 3.6). In this case the battery charge of the problematic nodes for the problematic hours is constrained to a value higher than the one calculated at the previous iteration by an predefined step (constraint 3.53). In case that APC is allowed, a second constraint is applied limiting the minimum curtailment levels of the voltage problematic nodes (constraint 3.54). This constraint is only activated if the curtailment allowable margins are not fully used. The minimum battery charges as well as the minimum PV curtailment levels per node and per time step are expressed with two power reference matrices. The modified Method \( b \) algorithm in case APC is also taken into account is explained in Section 4.1.5.

- Minimum battery charge in case of voltage violation identification (Method \( b \)):

\[
P_{B_{ch},t} \geq P_{B,t}^{ref}, \forall t \in [1..n_t] \tag{3.53}
\]

- Maximum PV generation in case of voltage violation identification (Method \( b \)):

\[
P_{g,t} \leq P_{g,t}^{max} - P_{cu,t}^{ref}, \forall t \in [1..n_t] \tag{3.54}
\]

where \( P_{B,t}^{ref} \in R^n_b \) and \( P_{cu,t}^{ref} \in R^n_b \) are the minimum battery charge and curtailment applied reference vectors respectively.

3.3.2 Objective function

As it is defined in the research objectives, the goal of this optimization formulation is to minimize the battery installation costs. The objective function consists of two different components: \( TC_{E_B} \), with a weighting factor around 0.99 and \( TC_{ES} \) with a weighting factor of 0.01. If curtailment schemes are also included into the optimization, a direct comparison between the battery installation costs and the APC costs is enabled by a third term \( TC_{cu} \). A more in detail analysis of the objective function components follows.
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Battery installation cost \((TC_{EB})\)

This term expresses the total installation cost of the battery storage system according to economies of scale. Only the fixed installation costs are taken into account in this algorithm. A linear cost function based on economies of scale is used:

\[
C_B = aE_{\text{inst}}^B + b \cdot 1^T
\]  

Therefore, the total cost of all the batteries installed in the system is expressed by a quadratic function of the battery installed capacity decision variable:

\[
TC_{EB} = \sum_{i=1}^{n_B} E_{\text{inst}}^B(i)C_B(i) = \sum_{i=1}^{n_B} (aE_{\text{inst}}^B(i)^2 + bE_{\text{inst}}^B(i))
\]  

where \(C_B \in \mathbb{R}^{n_B}\) is the battery cost vector in \(kCHF/MWh_{\text{installed}}\); \(a\) and \(b\) are the factors that define the economies of scale cost function. In this thesis, the values \(a = -500\) and \(b = 1000\) are chosen while the resulting battery cost function is depicted in Figure 3.7. These costs are based on an analysis concerning the installation cost development of Li-Ion batteries conducted by the “Bundesamt für Energie” [35].

Although a potential battery is installed to all the PV nodes of the network, only some of these locations will be chosen by the algorithm for actual battery installation. The selection of nodes and sizes will be thus made in such a way that the battery installation cost will be minimized according to the economies of scale, while no technical constraint violations are present in the network.

Economies of scale auxiliary cost \((TC_{ES})\)

The non-linearities introduced into the problem along with the big number of nodes in a real-scale LV network lead sometimes the optimizer to local minimum solutions. More specifically the nodes chosen for battery installation lead to a sub-optimum cost regarding the economies of scale. This means that nodes with bigger battery hosting capacity and hence a smaller cost overall are not chosen by the optimizer. Therefore, \(TC_{ES}\) is introduced into the objective function with a small weighting factor (\(~1\%\) of the objective function) in order to trigger the optimizer to the direction of the global minimum:

\[
cost_{ES} = c \sum_{i=1}^{n_B} (fP_{PV}^{\text{max}}(i) - E_{\text{inst}}^B(i))^2
\]  

Through \(TC_{ES}\) a penalty for the nodes with big battery hosting capacity that don’t get any battery installed by the optimizer, is applied. More specifically, the square of the difference between the maximum allowed battery installed capacity and the actual installed battery capacity per node is penalized. The factor \(f\) is related to the maximum allowed battery installed capacity (Constraint 3.42). The factor \(c\) is used to modify the weighting factor of this objective function component. In this thesis, the values 4 and 100
are chosen for $f$ and $c$ respectively. With this additional auxiliary component included in the objective function, the overall solutions have been verified to be the optimal ones.

Curtailment cost ($TC_{cu}$)
In case that the PV curtailment mode is enabled, the introduction of a curtailment cost component is required. The curtailment cost formulation depends on the desired operation mode. In this thesis two variations with APC schemes included are investigated:

- **Free curtailment**
  In this case a sufficiently small curtailment penalty is included in the objective function in order to avoid applying APC at hours that no technical constraints are present. Curtailment is always preferred to battery installation as it doesn’t incur any costs.

- **Curtailment cost directly compared to battery installation cost**
  The assessment of the most cost-efficient battery and PV curtailment allocation is included in the research questions of this thesis. To do so, a simulation framework for the direct comparison of battery installation costs to APC costs is introduced in Section 4.1.5.

In both cases the same function is used as basis for the calculations:

$$TC_{cu} = C_{cu} \sum_{i=1}^{n_p} \sum_{t=1}^{n_t} \left( P_{PV,i,t}^{\text{max}} - P_{G,t}(i) \right), \forall i \in [1 \ldots n_b] \setminus I_{\text{grid}}$$  \hspace{1cm} (3.58)
where the curtailment cost is given by:

\[ C_{cu} = LT_B C_{el} \]  

(3.59)

where \( LT_B \) is the battery lifetime and \( C_{el} \) is the cost of electricity in \( kCHF/MWh \). In this thesis, the battery lifetime is assumed to be 15 years, while a constant electricity price of 0.1CHF/kWh is used for the calculations. With this term the deviation of the actual PV production from the identified PV potential of each node \( i \) is penalized for each time step \( t \). If no curtailment is allowed or needed, all the PV generators will be operated at their peak according to constraint 3.40 and the curtailment cost component will be zero.

If a direct comparison between the curtailment costs and the battery installation costs is required, a slightly modified formulation is followed in order to simulate the sunshine hour difference between different seasons. This is presented in detail in Section 4.1.5.

3.3.3 Optimization problem overview

An overall summary of the optimization problem per method is provided below:

- **AC OPF**

  \[
  \min_{P_{G,t},Q_{G,t},E_{Bin},V_t,\theta_t} (TCE_B + TCE_S + TC_{cu})
  \]  

  subject to constraints: (3.32 – 3.38), (3.40 – 3.46), (3.48 – 3.52).

- **DC OPF**

  \[
  \min_{P_{G,t},E_{Bin},\theta_t} (TCE_B + TCE_S + TC_{cu})
  \]  

  subject to constraints: (3.33 – 3.36), (3.39 – 3.46), (3.48 – 3.52).

- **Method a: nested AC constraints**

  For the voltage problematic hours the optimization formulation of AC OPF is followed:

  \[
  \min_{P_{G,t},Q_{G,t},E_{Bin},V_t,\theta_t} (TCE_B + TCE_S + TC_{cu})
  \]  

  subject to constraints: (3.32 – 3.38), (3.40 – 3.46), (3.48 – 3.52).

  For the non-problematic hours the optimization formulation of DC OPF is followed:

  \[
  \min_{P_{G,t},E_{Bin},\theta_t} (TCE_B + TCE_S + TC_{cu})
  \]  

  subject to constraints: (3.33 – 3.36), (3.39 – 3.46), (3.48 – 3.52).
• Method b: iterative condition-based approach

In method b the problem is formulated according to DC OPF with two additional constraints:

$$\min_{P_{G,t}, E_{Binst}, \theta_t} (TC_{EB} + TC_{ES} + TC_{cu})$$

subject to constraints: (3.33–3.36), (3.39–3.46), (3.48–3.54).

3.3.4 Optimal battery dispatch problem

After identifying the optimal battery locations and sizes to address the constraint violations of the network, a second optimization problem dealing with the battery storage system dispatch is formulated. This second optimization problem uses the generated battery locations and sizes by the main algorithm as inputs in order to assess the optimal charging/discharging pattern of the battery storage system. The algorithm proposed in this thesis is optimizing the dispatch in terms of the LV area self-sufficiency maximization. More specifically, the algorithm aims to minimize the energy imports from the MV level.

The constraints of the battery dispatch optimization problem are identical with the constraints described in Section 3.3.1 per method considered. On the other hand, the objective function is formulated in such a way that the grid imports from the upper level are penalized. A virtual grid cost is therefore here defined:

$$TC_{grid} = \sum_{i=1}^{n_B} \sum_{t=1}^{n_t} P_{G,t}(i), \forall i \in I_{grid}, \forall P_{G,t}(i) > 0$$

where $$P_{G,t}(i), \forall i \in I_{grid}$$ refers to the virtual generation of the connection points to the MV level. A positive virtual generation at the grid connection nodes represents a grid import from the MV level. On the other hand, when there is a surplus of energy in the LV area, the export of energy to the MV level is expressed with a negative virtual generation at the grid connection nodes. The curtailment penalization cost has still to be taken into account in case that curtailment is allowed.

The optimal dispatch problem for the full AC OPF problem is therefore formulated below:

$$\min_{P_{B_{ch,t}}, P_{B_{dis,t}}, P_{G,t}, Q_{G,t}, V_t, \theta_t} (TC_{grid} + TC_{cu})$$

subject to constraints: (3.32–3.38), (3.40–3.46), (3.48–3.52).

The optimization problem can be formulated for the rest of the methods in the same way, with respect to the constraints presented in Section 3.3.3 per method.
3.3.5 Software packages

For the solution of the optimization problems defined in this thesis different programs and software packages were used. The size of the network, the multi-period character of the problem and the non-linear nature of the constraints necessitate the implementation of a reliable software package capable of handling large-scale nonlinear optimization problems. For these reasons, IPOPT, a nonlinear optimization solver is called from MATLAB. IPOPT, short for “Interior Point OPTimizer”, implements a primal-dual interior point method and uses line searches based on Filter methods [36].

The optimization formulation in MATLAB is done with the help of YALMIP, a toolbox that allows fast compiling of various optimization problems. YALMIP supports many different solvers and can be used for the formulation of a wide range of optimization problems [37].

When the formulation of a multi-period OPF is not necessary, the software package MATPOWER has been used. This is the case for the voltage violation controller used in Method b or for the single AC power flows needed for the identification of the voltage problem hours in Method a. MATPOWER is a specialized power flow package developed at Cornell University, which can solve AC-OPF problems in less than a second even for systems with hundreds of buses [38].
Chapter 4

Simulation Model and Data

In this chapter the simulation framework created for the distribution grid simulation along with the data used in this thesis, are presented. The application of these on a real network follows in the next chapter.

4.1 Models

The PF or OPF analysis of a distribution grid requires the modelling of all the network components. The first part of this section describes the network models used for loads, PV plants, lines and MV/LV transformer. The network model used in MATLAB has been exported from the DIgSILENT PowerFactory, a software used for power flow simulations. The conversion between the two programs has been facilitated with a MATLAB script developed at ETH Zurich by Marcus Imhof. First an excel file with all the grid data is exported from PowerFactory. The MATLAB script reads this excel file and generates the admittance matrices along with all the network elements in a format suitable for MATPOWER. The conversion process is depicted in Figure 4.1.

Figure 4.1: Network data conversion process.
4.1.1 Loads

The modelling of a typical house connection bus is depicted in Figure 4.2. Each house connection represents a bunch of separate households, while a power factor of 0.95 inductive is assumed for the load demand. The active and reactive peak power demands $P_{L}^{\text{max}}$ and $Q_{L}^{\text{max}}$, $\in \mathbb{R}^n_b$ are determined for each house connection based on the following factors [39]:

- Maximum load of the MV/LV substation.
- Population density of the building zone.
- Number of households connected to the house connection node.

The peak load per node is subsequently scaled for every time step according to the time series measurements that are presented in Section 4.2.1.

![Figure 4.2: House connection model including the PV generator, load demand and battery storage system.](image)

4.1.2 PV Plants

The purpose of the algorithm developed in this thesis is to integrate the full PV potential of a LV grid area. The existing PV penetration in the distribution grid is very small, thus the PV potential installed capacity of each roof area is used instead. The yearly PV
production potential of each rooftop is assessed through “Solarkataster Stadt Zürich”, a GIS application of the city of Zurich used for the identification of solar potential [40]. Only roofs with a minimum area of $14m^2$ and a solar radiation potential larger than 75% of the optimum global radiation are taken into account while the PV efficiency is assumed 15%. Subsequently, the aggregated PV potential of all rooftops connected to the same node are assigned to one single house connection bus. The installed capacity of the modelled PV plants is calculated according to the following empirical formula [39]:

$$P^{\text{max}}_{PV}(i) = \frac{E^\text{year}_{PV}(i)}{\text{hours}^\text{sun}_\text{year}}, \forall i \in [1 \ldots n_b]$$  (4.1)

where $E^\text{year}_{PV} \in R^{n_b}$ is the assessed through Solarkataster yearly PV potential yield in kWh while $\text{hours}^\text{sun}_\text{year}$ express the sunshine hours per year. In this thesis, a value of 900 sunshine hours is used for Zurich. Finally, the PV plants are modeled with a unity power factor.

In addition to Solarkataster, in [41] an external study with different assumptions concerning the assessment of the PV potential is carried out. The PV potential identified in this study corresponds to 210% of the corresponding PV potential assessed through Solarakataster for the LV grid area that is used in this thesis as a case study. The reason for the increased PV potential is the assumption of a higher PV efficiency and the denser installation of PV panels on the available roof area. In Section 5.1.3, scenarios investigating the effect of an increased PV penetration in the case study area, are formulated.

### 4.1.3 Lines and transformers

For the lines and transformers of the network, the lumped-circuit line model described in Section 3.1.1 is used. The shunt conductance $g^{sh}_{km}$ is neglected in this thesis.

### 4.1.4 Battery storage system

The operation of the battery storage system model used in this thesis is demonstrated in Figure 4.3. An one-way charging / discharging efficiency of 0.95 is used, while the upper and lower allowable SOC limits are 90% and 10% of the installed capacity respectively. The battery storage behaviour is described by the constraints (3.42-3.52) given in Section 3.3.1.

The batteries size in terms of capacity and power are optimization variables. The most usual battery storage type for such applications is lithium-ion batteries. However, choosing a specific type of storage system is out of the scope of this thesis, since it has a limited effect on the calculations. Practically a wide range of storage types could be chosen.
4.1.5 Active power curtailment model

As described in Section 1.2.6, APC is an alternative PV integration measure. The downside of such a measure is the energy losses resulting from the PV peak shaving. Since the DSO would have to reimburse the PV owners for these losses, the curtailment cost must be taken into account in the selection of the optimal measure combination. When curtailment is not allowed, the minimum allowable PV production is constrained to be equal to the PV potential. As a result, the full PV potential is produced at all time steps. However, if curtailment is allowed, the minimum PV production is constrained according to the maximum allowable curtailment level. This constraint is expressed with Eqs. 3.40 and 3.41. The curtailed energy is penalized with an electricity price of $\text{Cost}_{el} = 0.1 \text{ CHF/kWh}$ in the objective function (Eq. 3.58).

The direct comparison between battery installation and curtailment costs requires the creation of a simulation framework that takes into account seasonal effects. Although the required installed battery capacity to address all constraint violations can be assessed by modelling only the worst-case day of the year in terms of constraint violations, the seasonality of the PV infeed need to be considered for the assessment of the yearly curtailment costs. Since modelling the whole year would be computationally intractable, an alternative approach based on one typical and one worst-case day per season, is suggested here.

A typical day refers to a day with the average PV infeed and load demand for each season of the year, while the worst-case day in terms of constraints violations is identified a priori with simple PF analyses of the whole year. Although the worst-case day per season is appearing only once per season, there are more days with constraint violations of similar...
severity in the same season. Therefore, in this thesis 6 worst days and 84 typical days are assumed per season. The typical and worst-case days distribution throughout the year is visualized in Figure 4.4.

If voltage violations are identified in Method $b$ and curtailment is allowed, a decision has to be made by the algorithm about which of the two possible PV measures will be employed to resolve the voltage problems. The modified Method $b$’s flowchart, depicting the decision process is presented in Figure 4.5. If the main problem of the network is the transformer overloading, the total network’s installed battery capacity from the first iteration might suffice for the mitigation of the voltage problems if it is shifted to the voltage problematic nodes. This results from the utilization of DC equations in Method $b$: the total battery installed capacity needed to face a transformer loading problem is not dependent on the battery locations since no ohmic losses are taken into account. In this case, a simple shift of battery charge from non-problematic nodes in terms of voltage violations to nodes that present voltage rises would suffice. This way, the total cost per iteration remains constant.

On the other hand if the major problem of the network is voltage violations, the already installed battery capacity by previous iterations may not be enough to cover the battery charge shifting needs to solve the voltage problems. In this case a cost comparison between the battery and curtailment cost to cover the additional needs is done. In case curtailment is proved to be more cost-efficient than battery installation for a time horizon corresponding to the battery’s lifetime, APC is preferred for the mitigation of the voltage problems.
Figure 4.5: Modified flowchart for Method b in case APC is allowed.

4.1.6 Losses approximation

In this thesis four different methods with different considerations of variables and constraints are suggested. In DC OPF, Method b, as well as in the voltage non-problematic hours in Method a, the simplified DC equations are used. In these cases, the network ohmic losses are disregarded and thus different results are obtained compared to the cases that the full AC equations are used. In order to resolve this issue, a simple losses approximation model is implemented when the simplified DC equations are used.

If the losses approximation mode is enabled, \( n_t \) preliminary AC PF simulations are run with MATPOWER and the line losses \( P_{\text{losses},t}, \forall t \in [1..n_t] \) are assessed. Subsequently,
the line losses are distributed to the PV generators according to their production. In this way, the line losses are simulated by virtually reducing the PV infeed for each time step. With this simple model only a rough approximation of the losses can be achieved, since during normal operation the losses occur on the lines and not at the PV plants connection points. However, results closer to reality can be obtained that way. In the calculations performed in this thesis, the line losses account to no more than 1% of the line flows.

4.1.7 Single Power flows

The execution of multiple single Power flow calculations is required sometimes in the two hybrid methods suggested in this thesis. In these cases MATPOWER is used, due to its very small computational times for single-period power flows. In some cases, preliminary power flow analyses are performed (e.g. identification of voltage problematic hours in Method a, while in other cases a power flow analysis is needed after the execution of the OPF (e.g. voltage violation control in Method b). MATPOWER is used in the following cases:

- Identification of voltage problematic hours in Method a.
- Assessment of line losses if the DC equations are used.
- Voltage violation control in Method b.
- Identification of voltage problematic hours and nodes in Method b.

4.1.8 Self-consumption and self-sufficiency factors

Apart from mitigating the technical constraint violations, the batteries can also boost the degree of self-sufficiency of a household with installed PV panels. Since the energy cost becomes more expensive and the feed-in-tariffs decline, this index can be considered in the design of a PV system in conjunction with battery storage.

Although the main objective of this thesis is the identification of the optimal battery sizes and locations, a second algorithm for the maximization of the LV grid self-consumption rate is suggested. The optimization formulation of the optimal battery dispatch problem can be found in Section 3.3.4.

In this thesis the LV grid area self-consumption rate and degree of self-sufficiency are used as assessment criteria. The self-consumption rate refers to the share of the PV produced energy that is used directly or indirectly to satisfy the local needs. A self-consumption rate of 1 would mean that the full PV production of a LV grid area is used locally. This can be the case for either a small PV capacity or a big PV capacity combined with battery storage. On the other hand the degree of self-sufficiency corresponds to the share of the load demand served either directly or indirectly by the PV production. Therefore, a self-sufficiency rate of 1 would indicate an 100%, direct or indirect coverage of the load.
demand by the PV produced energy, while a household with a zero self-consumption rate would not have any of its load demand covered by PV energy. Sensitivity analyses examining the effect of varying PV penetrations and battery storage system sizes on these two factors are carried out in [42]. In this thesis, the symbols \( \xi \) and \( \psi \) are used for the degree of self-sufficiency and the self-consumption rate respectively. The definitions are given below:

\[
\psi = \frac{E_{\text{direct}}^{\text{PV}} + E_{\text{bat}}^{\text{PV}}}{E_{\text{PV}}} \tag{4.2}
\]

\[
\xi = \frac{E_{\text{direct}}^{\text{PV}} + E_{\text{bat}}^{\text{PV}}}{E_L} \tag{4.3}
\]

where \( E_{\text{direct}}^{\text{PV}} \) is the direct use of the PV energy by the load demand; \( E_{\text{bat}}^{\text{PV}} \) is the indirect use of the PV energy by the load demand through the battery; \( E_L \) is the energy consumed by the loads and \( E_{\text{PV}} \) is the overall produced PV energy.

### 4.2 Data basis

An accurate and realistic simulation of a distribution grid with PV penetration requires a consistent and realistic data basis. The data sources used for the assessment of the load demand, PV production and electric mobility time series curve is the main subject of this section.

#### 4.2.1 Load profile

In section 4.1.1 the model of the load elements is presented. Load demand of each house connection is scaled according to the measured substation loading. The load profiles used in the simulations correspond to transformer loading measurements recorded in 2013 at “Hüslibachstrasse”, a MV/LV substation of ewz in the city of Zurich. More specifically 35040 transformer loading values have been acquired, which corresponds to a temporal analysis of 15 minutes. These values are subsequently scaled to the energy demand of each house connection node according to the 3 factors listed in section 4.1.1. The load demand coincidence factor is also taken into account in the calculations.

In Figure 4.6, the load demand data basis used in this thesis is presented. A transformer loading of 1 p.u. refers to the maximum measured transformer loading which was recorded on the 23rd of February at 18:45. The minimum transformer loading during 2013 is measured on the 7th of July at 06:00. In this thesis, a temporal analysis of 1 hour is preferred, in order to reduce the algorithm computational time.

A load scaling factor \( SC_{L,t}, \forall t \in [1..n_t] \) is here defined. All the house connection loads are scaled according to this factor for each time step. The active and reactive load
demand vectors are hence given by the following equations:

\[ P_{L,t} = SC_{L,t} P_{L,\text{max}}, \forall t \in [1..n_t] \] (4.4)
\[ Q_{L,t} = SC_{L,t} Q_{L,\text{max}}, \forall t \in [1..n_t] \] (4.5)

### 4.2.2 PV profile

For the generation of a PV profile, real PV measurement data were used. Since the current installed PV capacity of the “Hüslibachstrasse” substation is negligible, PV measurements from 288 different PV plants installed in Zurich are used as an input. The aggregated power output in time intervals of 15 minutes is shown in Figure 4.7. The values are presented in p.u. format, with 1 p.u. referring to the maximum aggregated measured PV infeed.

A PV scaling factor \( SC_{PV,t}, \forall t \in [1..n_t] \) is here defined. The active PV production vector is therefore given by:

\[ P_{G,t} = SC_{PV,t} P_{PV,\text{max}}, \forall t \in [1..n_t] \] (4.6)

where \( P_{G,t} \in \mathbb{R}^{n_t} \setminus I_{grid} \) is the PV active power generation vector.
4.2.3 Electromobility profile

To generate realistic electromobility data an electric vehicle profile generator developed at ETH Zurich was used [43]. One electric vehicle per household was assumed for the assessment of the load curve. This number corresponds to a population of 805 electric vehicles within the limits of the LV grid under investigation. The electric vehicles are modelled with a battery of 24kWh, while their average charging power is assumed to be 3kW. The seasonality is assumed to have no effect on the electric fleet charging patterns, therefore a single daily profile with a 15 minutes temporal resolution has been produced. According to this model, the peak electromobility demand of the LV area accounts for 29.7% of the maximum measured aggregated load in 2013. The resulting electromobility profile is provided in Figure 4.8 in p.u. format, with 1 p.u. referring to the maximum electric mobility demand.

4.2.4 Identification of critical cases

The simulation of all 365 days of a year would create an immense, non-linear multi-period optimization problem. The intractability of such a problem necessitates the identification and simulation of only the critical cases in terms of constraint violations.

A preliminary PF simulation of all the 35040 time steps has been carried out in PowerFactory in order to identify the critical case time steps. Three different extreme situations can occur:

- Worst-case transformer loading energy-wise
• Worst-case transformer loading power-wise
• Worst-case voltage rise

The first situation refers to the total energy within a day that cannot be served by the transformer station’s capabilities. On the other hand, the worst-case transformer loading in terms of power has to do with the instantaneous transformer overloading in kW. The first type of constraint violation will affect the dimensioning of the installed battery capacity, while the second one will determine the power rating of the batteries. Finally, the worst-case voltage rise day could affect both the installed battery capacity and the batteries power rating.

In the preliminary PF simulation, it is shown that the two latter worst-case days coincide on the 18th May for 2013, while the worst-case day in terms of cumulative daily transformer overloading is identified to be the 6th June. The reason for this discrepancy is that although the peak power production occurs in May, more sunshine hours per day can be seen in June. In the 8-day simulation mode depicted in Figure 4.4, both the critical days identified are taken into account as worst-case spring and worst-case summer day respectively. If it is not stated otherwise, the one-day simulations are done for the 6th June.
Chapter 5

Simulations

In this chapter a demonstration of the models and methods suggested in this thesis is made. The optimal placement, sizing and dispatch of a battery storage system in a real-scale network is assessed for different operating conditions. For this purpose, a substation area in the LV network of Leimbach, in the outskirts of Zurich is chosen. Before the application of the methods on the full network, the functionality and performance of the methods is tested on a part of the full network that is used as a benchmark network. Results about the cost-optimal placement and sizing of the battery storage system to address the constraint violations as well as about the optimal battery dispatch in terms of the LV grid area self-sufficiency maximization are presented in this chapter. Finally, sensitivity analyses with a varying allowable curtailment level, battery price and PV potential are carried out and discussed.

5.1 Case study Leimbach

Leimbach is a mainly residential district in the southern periphery of the city of Zurich. Its relatively low load density in combination with large available roof areas makes it an ideal case study for the demonstration of the impact of PV penetration on LV grids. In this thesis, the “Hüslibachstrasse” LV area fed by two 630 kVA MV/LV transformers, is chosen as a case study. The strongly meshed network topology of “Hüslibachstrasse” is presented in Figure 5.1, while an overview of the area in GoogleMaps is provided in Figure 5.2. The part of the network that will be used as a benchmark grid is highlighted in the bottom right corner.

5.1.1 Full network

The LV area under investigation is part of a MV ring comprising of four more MV/LV transformers. In the area supplied by the “Hüslibachstrasse” transformer station, approximately 1300 people live while roughly 0.4 km² of roof area have been identified as suitable for PV installation according to the GIS “Solarkataster” application of the city.
of Zurich, as described in Section 4.1.2. The most important parameteres of the full “Hüslibachstrasse” LV area are shown in Table 5.1.

The PV potential of the network corresponds to a value 2.8 times higher than the peak load of the network. However, the maximum PV infeed, that appears in summer, would not coincide with the peak load demand which happens in winter. A value of 5.4 is observed for the total PV infeed to peak load ratio at the maximum PV infeed time point on the 18th May. The total battery installation potential, that depends on the installed PV capacity per node, could cover 55% of the maximum daily PV production. Since the biggest battery that currently exists in Switzerland is 1MWh [22], the maximum allowable transformer station battery capacity is chosen accordingly. The transformer station’s battery capacity depends on the available physical space that the distribution system operator can reserve for the installation of a battery system.

5.1.2 Benchmark network

A part of the full “Hüslibachstrasse” network with 27 out of the total 254 nodes is isolated to benchmark the methods suggested in this thesis. The benchmark network’s topology is depicted in Figure 5.3, while the parameters are provided in Table 5.1. The benchmark grid consists of 3 parallel feeders that connect the transformer station with
Figure 5.2: Overview of the “Hüslibachstrasse” substation area.

Table 5.1: Parameters of the full “Hüslibachstrasse” network.

<table>
<thead>
<tr>
<th>Network Characteristics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of customers</td>
</tr>
<tr>
<td>Number of nodes / house connections</td>
</tr>
<tr>
<td>Number of lines</td>
</tr>
<tr>
<td>Maximum load</td>
</tr>
<tr>
<td>Yearly load consumption</td>
</tr>
<tr>
<td>Total PV potential</td>
</tr>
<tr>
<td>Yearly PV production</td>
</tr>
<tr>
<td>Maximum daily PV production</td>
</tr>
<tr>
<td>Total battery installation potential</td>
</tr>
<tr>
<td>Maximum allowable battery capacity at the TS</td>
</tr>
<tr>
<td>MV / LV Transformer</td>
</tr>
</tbody>
</table>

\(^a\)Only the house connection nodes are eligible for battery installation.

the distribution cabinet VK01080 of the ewz LV grid. Therefore, as the full network, the benchmark network presents also a meshed topology. In total 12 out of the 111 house connections modelled in the full network are present in the reduced case.

If the benchmark network was used as an input to the optimization tool without any changes, no technical violations would be identified and hence no batteries would be
Table 5.2: Parameters of the benchmark “Hüslibachstrasse” network.

<table>
<thead>
<tr>
<th>Network Characteristics</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of nodes / house connections</td>
<td>27 / 12&lt;sup&gt;a&lt;/sup&gt;</td>
</tr>
<tr>
<td>Number of lines</td>
<td>28</td>
</tr>
<tr>
<td>Maximum load</td>
<td>0.124 MW</td>
</tr>
<tr>
<td>Yearly load consumption</td>
<td>0.58 GWh</td>
</tr>
<tr>
<td>Total PV potential</td>
<td>0.398 MWp</td>
</tr>
<tr>
<td>Yearly PV production</td>
<td>0.47 GWh (81% of yearly load)</td>
</tr>
<tr>
<td>Maximum daily PV production</td>
<td>3.33 MWh</td>
</tr>
<tr>
<td>Total battery installation potential</td>
<td>1.8544 MWh</td>
</tr>
<tr>
<td>Maximum allowable battery capacity at the TS</td>
<td>0.25 MWh</td>
</tr>
<tr>
<td>MV / LV Transformer</td>
<td>2x200 kVA</td>
</tr>
</tbody>
</table>

*Only the house connection nodes are eligible for battery installation.

installed. The reason for this is that the distance of the house connection nodes from the transformer station is not enough for the appearance of voltage rises higher than 1.1 p.u., while the total PV energy surplus of the area is well beyond the loading limits of the transformer station. Therefore, in order to simulate the technical constraint violations that appear in the full network, some technical characteristics of the reduced network had to be modified:

- Increase of line impedances.
- Replace transformer with a smaller one.

The first modification aims at the simulation of the voltage violation problems of the full network, while the second one intents to the creation of transformer overloading equivalent to the ones observed in the full network.

5.1.3 Scenarios formulation

The different scenarios that are investigated in this thesis for both the benchmark and the full network are listed in Table 5.3. The first three scenarios are formulated for both the networks under examination while sensitivity analyses with regard to the allowed APC level are conducted in the two last scenarios for the full network.

In scenarios B1 / F1 the existing situation in the “Hüslibachstrasse” area, without any PV penetration is examined. The effect of PV penetration on the technical constraints is examined in scenarios B2 / F2. The main research question of this thesis is answered with scenarios B3 / F3, where optimal positions and sizes for a battery storage system are assessed aiming at the mitigation of the technical constraint violations.
**Table 5.3:** Scenarios under investigation.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Network</th>
<th>PV Potential</th>
<th>Batteries</th>
<th>ACL</th>
</tr>
</thead>
<tbody>
<tr>
<td>B1 / F1</td>
<td>Benchmark / Full</td>
<td>0%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>B2 / F2</td>
<td>Benchmark / Full</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>B3 / F3</td>
<td>Benchmark / Full</td>
<td>100%</td>
<td>Yes</td>
<td>-</td>
</tr>
<tr>
<td>F4</td>
<td>Full</td>
<td>100%</td>
<td>Yes</td>
<td>0-100%</td>
</tr>
<tr>
<td>F5</td>
<td>Full</td>
<td>150%</td>
<td>Yes</td>
<td>0-100%</td>
</tr>
</tbody>
</table>

In scenarios F4-F6 the focus is on the full “Hüslibachstrasse” network where different sensitivity analyses are carried out. In Scenario F4 and F5, the effect of the allowed curtailment level on the installed battery capacity required as well as on the total resulting cost, is examined for a PV potential of 100% and 150% respectively. The PV Potential is scaled according to the identified potential from Solarakataster, which corresponds to 100%. In 5.4.3, a PV potential of up to 200% is investigated through a sensitivity analysis.

An electromobility load is taken into account in variations of the scenarios described above. Scenario F3em denotes scenario F3 with an additional electromobility load. Moreover, the scenario F3 is examined in two additional investigations. In the first investigation, the economies of scale are disregarded and a constant cost function is assumed, while in the second one, the thermal overloading constraints are disregarded and the sizing and placement of the batteries is done based solely on the voltage violations.
**Figure 5.3:** The benchmark network topology with the constraint violations highlighted.
5.2 Benchmark network: methods performance assessment

The implementation of a multi-period battery allocation AC OPF algorithm to the full “Hüslibachstrasse” network results in an intractable optimization problem. Therefore, hybrid AC and DC methods are proposed in this thesis to render the problem tractable. The performance of the hybrid methods presented in Section 3.2, along with the existing classical AC and DC OPF formulations is first assessed for the reduced part of the full network described in Section 5.1.2.

In the first part of this Section, scenarios B1, B2 and B3 are investigated using the full AC OPF optimization formulation. The results acquired are used as a benchmark for the other methods. Next, various parametric investigations and sensitivity analyses on the hybrid methods is conducted in order to assess their performance in different situations. Conclusions about parameters’ optimal configuration are drawn. The four methods are finally compared in terms of computational time and in terms of the 1-norm of the resulting battery installed capacity vector $E_B^{\text{inst}}$.

5.2.1 AC Optimal Power Flow: Comparison between scenarios B1, B2 and B3

The cost-optimal battery placement and sizing is here investigated for the benchmark network with the full AC OPF formulation. In scenario B1 the existing situation without any PV plants in the system is presented, while scenario B2 shows the effect of PV penetration. In scenario B3 the mitigation of the technical constraint violations that the battery storage system brings, is shown.

The MV/LV transformer loading on the 6th June 2013 for the scenarios B1, B2 and B3 is depicted in Figure 5.4. As explained in Section 4.2.4, this day represents the worst-case day of 2013 in terms of cumulative transformer overloading throughout the day. In the existing situation, the maximum transformer loading is below 50%, thus the n-1 security concept is kept in case there is a failure in one of the two transformers. The PV penetration brings reverse power flows and consequently transformer overloading up to 158% between 11:00 and 17:00. The battery system installed in scenario B3 performs peak-shaving and reduces the transformer loading below the technical limit of 100%. The stored energy is discharged at night, resulting in very low transformer loading during these hours.

In Figure 5.5 the voltage of node 9, the node that presents the highest voltage rise, is shown for all three scenarios, while a histogram depicting the voltage distribution of all the network nodes per scenario is presented in Figure 5.6. The PV penetration results in voltage rises up to 1.14 at the node 9 of the network. The installation of battery storage brings all the network voltages below the predefined limit of 1.1 p.u.

In Appendix A, the cost-optimal battery allocation per method for the benchmark network is visualized. The battery sizes and locations chosen by the full AC formulation
for the mitigation of the technical constraints violation can be seen in Figure A.1. The maximum allowable battery installed capacity per node (Eq.3.42) is indicated by the circle size, while the actual battery installed capacity chosen by the optimizer is represented with the circle colored area. Due to the economies of scale taken into account for the battery installation cost (Figure 3.7), the optimizer has an incentive to install batteries at nodes with biggest allowable installed battery capacities in order to reduce the total installation cost. However, the voltage problems need to be treated locally, independently of the potential battery installation cost at the problematic node.

In the AC case, the battery allocation is done both according to the economies of scale as well as according to the voltage problems of the network. The resulting total installed battery capacity amounts to 700kWh, while the total battery installation cost is 625kCHF.

All problems are solved with the IPOPT solver, called through a MATLAB-YALMIP interface and using a 4 core machine (2.6 GHz) with 8 GB RAM. The full AC OPF problem for scenario B3 with a relative convergence tolerance of $10^{-3}$ takes 8 minutes on average to converge to the optimum solution.
5.2.2 DC Optimal Power Flow.

If the simplified DC power flow equations are used, a much faster solution can be achieved. The reduction of the non-linearities of the problem enables the coupling and simulation of multiple days. Figure 5.7 depicts the relation between the days coupled and the required time for the optimizer to find a solution to the problem.

The optimal battery placement and sizing for the simplified DC formulation can be seen in the Appendix A, in Figure A.2. In this case the battery allocation is done solely based on the economies of scale, since the voltages are disregarded in the DC OPF formulation. As a result, the battery capacity needed to address the transformer overloading problems is distributed by the optimizer among the three nodes with the biggest potential battery installed capacity. This results in lower battery costs compared to the full AC OPF formulation.

5.2.3 Method a: nested AC constraints

The optimal battery placement and sizing for Method a is visualized in Figure A.3. In this case the voltage violations are taken into account for the battery allocation, since an AC constraint formulation is chosen for the voltage problematic hours.
5.2.4 Method b.

The optimal battery placement and sizing for Method b is visualized in Figure A.4. As in Method a, the battery placement and sizing algorithm is also taking into account the voltage problematic nodes. Since Method b is an iterative procedure, the computational time needed for its convergence depends heavily on the power increment described in step 5 of Method b’s formulation (Section 3.2.2). A sensitivity analysis of the time required as well as of the total installation cost with a varying power increment is here carried out for the benchmark network and presented in Figure 5.8. A single power increment value that satisfies the time and accuracy requirements of this thesis can be chosen for further implementation on the full network investigations. As it can be seen in Figure 5.8, the effect of a smaller power increment on the total optimized battery installation cost is negligible. If the power increment is reduced from 5kW to 0.1kW, a cheaper solution by 0.23% is achieved, while the computational time rises significantly from 20 seconds that corresponds to 4 iterations, to 10 minutes that corresponds to 104 iterations. In this thesis a power increment of 2kW is chosen and used for the various investigations performed with Method b. In Figure 5.9, the development of the maximum network voltage after each Method b iteration is depicted. Although the initial maximum network voltage is above 1.13 p.u., the reallocation of the batteries results in a limitation of the voltage rise below 1.1 p.u.
**Figure 5.7:** Effect of the days simulated on the computational time for the DC OPF method.

**Figure 5.8:** Sensitivity analysis of the power increment used in Method b.
Figure 5.9: Evolution of the maximum network voltage after each Method b iteration.

5.2.5 Methods performance assessment.

The performance of the two hybrid methods developed in this thesis is compared with the performance of the existing AC and DC OPF formulations in terms of the three following indices:

- Battery allocation per node.
- Time needed for the convergence.
- Total battery installation cost.

The 1-norm or Taxicab norm is introduced to assess the allocation of the batteries per method in comparison to the benchmark AC method. The 1-Norm expresses the sum of the differences of the examined method’s installed battery capacity in relation to the battery installed capacity of the benchmark method for every node. Subsequently, the 1-Norm is normalized according to the total installed battery capacity of the AC benchmark method. The equation used for the calculation of the performance index is given below:

\[
\text{Norm}_X = 100 \left( \frac{\sum_{i=1}^{n_B} |E_{\text{inst}}^{B_X}(i) - E_{\text{inst}}^{B_{AC}}(i)|}{\sum_{i=1}^{n_B} E_{\text{inst}}^{B_{AC}}(i)} \right)
\]  

(5.1)
where $\mathbf{E}_{\text{inst}}^{B_X} \in \mathbb{R}^{n_B}$ is the installed battery capacity vector of the examined method and $\mathbf{E}_{\text{inst}}^{B_{AC}} \in \mathbb{R}^{n_B}$ is the installed battery capacity vector of the benchmark AC method.

The comparison of the normalized norm per method is shown in Figure 5.10. The result for the full AC formulation is naturally zero, since this method is used as a benchmark. On the other hand, the normalized norm value for the DC method is more than 50% since in this case the battery allocation does not take into account the voltage problems of the network. This is resolved in the two hybrid methods, where the normalized norm values are below 10% for both cases. The battery placement and sizing per node that these values are based on, is visualized and presented in Appendix A.

The computation time and the total battery installation cost per method is presented in Figure 5.11. The optimal placement and sizing optimization problem with the full AC formulation requires approximately 15 minutes to converge, while the simplified DC method can obtain the optimal solution in only 7 seconds. Method a, with 6 identified problematic hours takes almost 5 minutes to converge, while Method b finds a solution in 40 seconds after 7 DC OPF iterations. The lowest total battery installation costs are obtained with the DC method, since the voltage constraints are not active and the placement is done based solely on the economies of scale. Therefore, bigger and cheaper batteries are being installed. The highest cost of Method b in comparison to the DC formulation can be explained because of the reallocation of the battery capacity from big and cheap batteries to the problematic nodes where smaller batteries are installed. The differences between the AC method and Method a are a result of the imperfect losses.
approximation model that have been defined in Section 4.1.6.

Comparing the performance assessment indices analyzed above, Method b is chosen for the implementation on the full case study network analyzed in this thesis.

5.3 Case study: Hüslibachstrasse LV network

In this section the optimization tool is applied on the case study LV network of Hüslibachstrasse. As it is shown in Section 5.2.5, Method b is chosen for implementation on the full network. The optimal battery placement and sizing as well as the optimal battery dispatch for the Hüslibachstrasse LV network per scenario investigated are presented in Appendix B.

5.3.1 Scenarios F1, F2 and F3

A comparison between the three basic scenarios is carried out. Specifically, the effect of the PV penetration (scenario F2) on the existing, no-PV situation (scenario F1) is shown. The mitigating effect of the batteries installed is depicted in scenario F3. The MV/LV transformer loading for the 4 worst-case and 4 typical days for scenarios F1, F2 and F3 is presented in Figure 5.12. The worst-case days are taking into account the PV penetration (Scenario F2) and therefore they do not correspond to the worst-case days of scenario F1, in which no PV penetration is present. The time that Method b needed
for the convergence of the 8-days problem for Scenarios F1, F2 and F3, is 2, 3 and 53 minutes respectively. The first two problems are much faster computationally-wise, since they constitute feasibility problems and no optimization is done.

The maximum transformer loading of the Hüsilbachstrasse transformer station has been measured for 2013 on the 6th January and amounts to 70%. The 4 worst-case and 4 typical days model is given in Section 4.1.5, while the preliminary identification of the critical cases is explained in Section 4.2.4. In Figure 5.12 transformer overloads can be observed for the worst case of all four seasons. On the other hand, the PV penetration results in transformer overloads only for a typical summer day. There is a total of 505 overloading hours in the 2013 measurement data. The battery storage installation limits the transformer loading below 100% for all cases.

The voltage of the worst-case node in terms of voltage rise for Scenario F2 is presented for all three scenarios in Figure 5.13. The maximum voltage rise for 2013 has been identified on the 6th June, which corresponds to the “worst-case summer” day. The node where the maximum voltage rise can be observed corresponds to the house connection “Stotzstrasse 61”, a node in the periphery of the LV network under examination. The same node presents the maximum voltage drop, equal to 7%, for the scenario F1 on 6th January 2013. The PV penetration results in voltage rises above the +10% limit specified by EN50160 for the worst-case days of spring, summer and autumn. In total, 125 voltage violation hours can be recorded for the measurement data used for 2013.

In scenario F2, the PV penetration has caused increased line flows in comparison to scenario F1. However, these flows do not exceed the thermal limit of the cables in any case throughout the year, hence the cable loading results are not presented.

The optimal battery placement and sizing for the Hüsilbachstrasse network and for scenario F3 is depicted in Appendix B in Figure B.1. The maximum allowable battery installed capacity per node (Eq.3.42) is indicated by the bar size, while the actual battery installed capacity chosen by the optimizer is represented with the colored bar area. As in the benchmark network, the biggest battery is installed in the transformer station, where a battery installation capacity of 1MWh is assumed. The voltage problems at the remote nodes of the network are mitigated by the placement of smaller batteries. The voltage problems at the nodes highlighted red that don’t get any battery installed are addressed by battery installation at neighbouring nodes. The total installed battery capacity needed to face all the constraint violations amounts to 3.7 MWh which corresponds to a total cost of 3 mi.CHF.

The biggest battery in terms of both energy capacity and power is installed at the transformer station with an installed battery capacity of 1 MWh and a power rating of 277 kW. These values correspond to an energy capacity to power capability ratio of 3.6, while ratios of up to 6.2 can be observed at the rest of the nodes. The smallest battery installed by the optimizer corresponds to 2.4 kW at three of the voltage problematic
nodes of the network. These batteries have a ratio of energy capacity to power of 1.2, since they are only needed to address a voltage violation problem during one specific time step. The total installed battery power capacity is 780 kW which gives a total installed battery capacity to power ratio of 5.2.

After the optimal battery locations and sizes are determined, a second algorithm is used for the battery dispatch optimization in terms of the LV-grid self-sufficiency maximization. The computation time needed for the convergence of the optimal dispatch problem
for Scenario F3 was 11 minutes. The optimal dispatch for Scenario F3 and for the 8-days problem is presented in Figure 5.14.

The degree of self-sufficiency of the Häslibachstrasse LV network for scenario F3 defined by the Eq.4.3, is calculated to be 56%. This means that 56% of the total yearly load can be covered directly through PV production or indirectly through the PV energy stored in battery storage. The aggregated self-consumption rate of the LV grid area PV systems is 72%. The degree of self-sufficiency and the self-consumption rate for the no-batteries situation (Scenario F2) amounts to 38% and 49% respectively. Therefore, apart from resolving the constraint violations, the battery storage installation results in an increase of almost 50% in the load that can be served by the LV grid area’s PV production. Scenario F1 presents naturally a 0% self-consumption and self-sufficiency factor since no PV penetration is assumed in this scenario.

As it is shown in Figure 5.14, the optimum dispatch algorithm results in a charge up to the maximum allowable battery SOC for the worst-case days of all the seasons as well as for the typical spring and summer days. For the case of a typical winter, the PV infeed is only enough to cover the load at the time of production, so the battery storage is not used. On the other hand, on a typical summer day, the transformer loading is reduced below the limit of 100% (Figure 5.12) in order to fully exploit the battery capacity and reduce the grid import demand at night.

5.3.2 Scenario F3em.

Scenario F3em refers to scenario F3 with an additional electromobility load, as described in section 4.2.3. The optimal placement and sizing of the battery storage system for scenario F3em is presented in Appendix B in Figure B.2. A reduction of 33% can be observed in the total required installed battery capacity due to the additional electromobility load. The total installed battery capacity for scenario amounts to 2.6 MWh, which corresponds to a total installation cost of 2 mi.CHF. The transformer overloading for the worst-case summer day can be identified from 10:00 to 18:00 (Figure 5.4). Therefore the noon electromobility peak around 12:00 as well as the rise of the charging demand after 15:00 can reduce the transformer loading during these hours, resulting in a smaller required battery capacity.

Figure 5.15 shows the energy balance of the LV grid area and the total battery SOC as they result from the optimum battery dispatch algorithm. A self-sufficiency factor of 45% can be achieved in this case. This value is smaller than in the no-electromobility Scenario F3, as the reduced size of the battery can cover a smaller part of the evening load demand. On the other hand, the increased load during PV infeed hours results in a rise of the self-consumption rate from 72% to 75%.
5.3.3 Scenario F4 with ACL=10%

In Scenario F4, APC is implemented in conjunction with battery storage for the mitigation of the constraint violations. In this section, a scenario with a maximum ACL of 10% is investigated.

The results of the optimum battery placement and sizing algorithm are visualized in Appendix B in Figure B.3. By implementing an ACL of 10%, battery reduces from 3.7 MWh for Scenario F3 to 2.1 MWh, i.e., by 43%. The battery installation costs are reduced from 3 mi.CHF to 1.5 mi.CHF, respectively. The batteries needed to address the local voltage problems are much smaller than in Scenario F3, since the majority of the violations is mitigated by the curtailment applied to these nodes.

In Figure 5.16 the optimum dispatch algorithm results are visualized. The degree of self-sufficiency for Scenario F4 with an ACL of 10% is 49%. The self-consumption rate is reduced to 64% due to the APC implemented. As it is shown, a curtailment of 10% is necessary only during the worst-case summer and spring days, since the installed battery storage of 2.1 MWh is sufficient to address the constraint violations during the other days. In the 8-days model described in Section 4.1.5, 6 worst-case days per season are assumed. Therefore, this would correspond to curtailment applied on 12 critical days in summer and spring for the scenario examined in this section. Under these assumptions the total yearly energy curtailment losses correspond to 0.46% of the yearly PV production. The reduced installed battery capacity due to curtailment results in a full utilization of the battery capacity for 7 out of the 8 days simulated. On a typical winter day, the PV infeed is lower than the load demand for all the time steps and therefore the battery is not used.

5.3.4 Scenario F4 with ACL=100%

In case a completely free curtailment mode is selected (ACL=100%), the constraint violations of the network are resolved solely by curtailing the excess PV energy. This is due to the fact that APC is a more cost-efficient solution than battery storage for the current battery and electricity prices.

Since there are no batteries installed in this Scenario, the total yearly curtailed energy per node is presented instead. More specifically, in Figure B.4, the total PV energy that needs to be curtailed in one year along with the maximum APC level applied per node, is depicted. The highest APC curtailment levels as well as the biggest amounts of curtailed energy can be observed at the voltage problematic nodes. The highest APC level and total curtailed energy can be observed at “Tuschgenweg 97” (node 28) corresponding to 62% and 1.2 MWh curtailed respectively. The installed PV capacity at the node “Tuschgenweg 97” is 25 kWp, while the total yearly PV potential yield at the same node amounts to 31 MWh.

Curtailment is applied to all PV nodes, with the majority of the nodes presenting a maximum APC level between 20% and 40%. The total yearly energy losses of the LV area
are 60 MWh or 2% of the yearly potential PV energy yield. With an assumed electricity price of 100 CHF/MWh, the total yearly curtailment cost amounts to 6 kCHF. If this cost is extrapolated to an assumed battery lifetime of 15 years, a total cost of 90 kCHF results. Therefore, APC proves to be a much more cost-efficient solution than battery storage since the required cost for battery storage in scenario F3 is 3 mi.CHF.

Based on the above, a sensitivity analysis examining the effect of declining battery prices is conducted in Section 5.4.2. Additionally, another sensitivity analysis with a varying ACL for 4 different scenario combinations is presented in Section 5.4.1.

As the resulting total installed battery capacity is zero in this scenario, the optimal battery dispatch algorithm is not performed. The LV grid area energy balance can be seen in Figure 5.17. The curtailment of energy is required for the worst-case spring, summer and autumn days as well as for a typical summer day, since transformer overloading has been identified on these days (Figure 5.12) for Scenario F2.

5.3.5 Scenario F5 with ACL=0%

As described in Section 4.1.2, an increased by 210% PV potential has been identified for the Hüslibachstrasse LV grid area by an external report. In this scenario, a PV potential corresponding to 150% of the one identified through Solarkataster is assumed.

The results of the battery placement and sizing optimization tool for Scenario F5 are shown in Figure B.5. In this case, the voltage problems appear also to other parts of the network due to the increased PV penetration. The total installed battery capacity needed amounts to 12.85 MWh, which corresponds to an increase of 247% in relation to Scenario F3. Respectively, a battery installation cost from 3 mi.CHF to 10.5 mi.CHF can be observed.

In Figure 5.18, the optimal battery dispatch along with the LV grid area energy balance, are presented. The increased PV penetration results in this case to a self-sufficiency factor of 80%. This value could be slightly higher without the terminal battery constraint. The only days that the load demand cannot be entirely covered by the PV production are the typical winter and autumn days. The PV production during the rest of the days is so high that there is grid export even during the evening hours due to the excess battery energy stored during the PV infeed hours. This excess PV production results in a decrease in the self-consumption factor to 70%.

Unlike Scenario F3 where the battery could reach its maximum SOC for 6 out of the 8 days, in Scenario F5 this is the case only for the worst-case summer day. This means that the battery will be maximally charged only for 6 days in one year, which indicates cost-inefficiency in battery dimensioning. The implementation of low allowable curtailment levels could reduce drastically the required battery capacity, increasing at the same time the battery utilization factor.
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A comprehensive sensitivity analysis with a varying PV potential for different load demand scenarios is presented in Section 5.4.3.

5.3.6 Additional investigations.

In addition to the scenarios of Table 5.3, two more variations of Scenario F3 are investigated in this Section.

In the first scenario variation, a constant cost function instead of the linear of Figure 3.7, is assumed. The resulting objective function is now:

\[ \min \sum_{i=1}^{n_B} bE_{\text{inst}}^B(i) \]  \hspace{1cm} (5.2)

where \( b \) is the constant expressing the battery installation cost per MWh installed. In this case a value of \( b=1000 \text{ kCHF/MWh} \) is used. The resulting battery allocation is depicted in Figure B.6. An homogeneous battery allocation can be observed. The same battery capacity is also installed in the voltage problematic nodes, which is enough to resolve the voltage rises already from the 1st iteration of Method b. The total cost in this case is 3.7 mi.CHF, while the total required installed battery capacity is identical with Scenario F3. The battery optimum dispatch is exactly the same with Scenario F3, shown in Figure 5.14.

In the second scenario presented in this section, the battery allocation pattern in case the thermal constraints of the network are disregarded, is examined. The total installed battery capacity that is required to resolve exclusively the voltage problems of the network is calculated in this scenario. The results of the optimization tool application on the Hüslibachstrasse network are visualized in Figure B.7. In this case, a battery is installed in each one of the nodes that present a voltage constraint violation. The total installed battery capacity amounts to 257 kWh, that corresponds to an installation cost of 252 kCHF. If these values are compared to the corresponding values assessed for Scenario F3, it can be concluded that transformer overloading is the main problem of this LV network.

5.3.7 Scenarios overview

In this section an overview of the scenarios investigated is provided. The installed battery capacity, the total battery installation cost, the degree of self-sufficiency, the self-consumption rate and the total APC cost for 15 years are presented per scenario investigated in Table 5.4.

Scenario F5 presents the biggest required installed battery capacity and consequently the biggest battery installation costs due to the increased PV potential. The biggest degree of self-sufficiency can also be achieved in Scenario F5, since the increased PV penetration increases the autarky of the LV grid area. On the other hand the highest
self-consumption rate can be observed in Scenario F3em. In this case, the consideration of an additional electromobility load increases the demand and consequently the local consumption of the PV generation rises.

### 5.3.8 Methods’ comparison

The results presented above have been obtained by applying Method b. In this section, the other three methods are also applied on the full Hüslibachstrasse LV network for the base scenario F3 considering the worst-case summer day. In Table 5.5 a comparison of the computation time, the total installed battery capacity as well as the total battery costs is presented.

The full AC formulation of the PF equations results in an intractable problem for the implementation of Scenario F3 on the on the full Hüslibachstrasse LV network. For the other three methods the same pattern observed in the benchmark network in Figure 5.11 can be also seen here. The consideration of AC constraints for 4 problematic hours, out of the the 24 time steps in total, results in a computation time of almost 3 hours for Method a. On the other hand the simplified DC formulation takes only 20 seconds to find a solution, while Method b needs 4 iterations, that correspond to slightly more than one minute, to converge. The differences in the installed capacity between the two methods that follow the DC formulation and Method a can be explained by the imperfect losses approximation model implemented. Method b presents a slightly higher cost than the DC method due to the reallocation of the battery capacity to smaller and more expensive batteries.

<table>
<thead>
<tr>
<th>Method</th>
<th>AC</th>
<th>DC</th>
<th>Method a</th>
<th>Method b</th>
</tr>
</thead>
<tbody>
<tr>
<td>Computation time (mins)</td>
<td>N/A</td>
<td>0.3</td>
<td>167</td>
<td>1.3</td>
</tr>
<tr>
<td>Installed battery capacity (MWh)</td>
<td>N/A</td>
<td>3.72</td>
<td>3.79</td>
<td>3.72</td>
</tr>
<tr>
<td>Battery installation cost (mi.CHF)</td>
<td>N/A</td>
<td>2.96</td>
<td>3.04</td>
<td>2.97</td>
</tr>
</tbody>
</table>

Table 5.5: Results for scenario F3 per method examined.
Figure 5.14: Battery optimal dispatch for scenario F3.
Figure 5.15: Battery optimal dispatch for scenario F3 with electromobility load.
Figure 5.16: Battery optimal dispatch for scenario F4 with ACL = 10%.
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Figure 5.17: LV grid area energy balance for scenario F4 with ACL=100%.
Figure 5.18: Battery optimal dispatch for scenario F5 with ACL=0%.
5.4 Sensitivity analyses

The results of the optimal placement and sizing algorithm under varying operating conditions are examined in this section with the implementation of three different sensitivity analyses. In the first one, the effect of a varying ACL on the required battery installed capacity is assessed for 4 different PV potential - load demand combinations. In the second sensitivity analysis the impact of declining battery prices is examined from a pure DSO perspective. Finally, in the last sensitivity analysis the total required installed battery capacity for various PV potential - load demand combinations, is assessed.

5.4.1 Varying ACL

The effect of the ACL on the total required installed battery capacity for the Hüslibachstrasse LV network is depicted in Figure 5.19. Four different scenarios are examined: 100% PV potential with and without electromobility and 150% with and without electromobility. The values for ACL=0% that are shown on the left side of the graph, correspond to the values presented in Sections 5.3.1, 5.3.2 and 5.3.5 for the scenarios F3, F3em and F5 respectively. An increasing ACL results in a decrease of battery capacity needs, since the constraint violations are resolved by curtailing the excess PV energy. For the case of 100% PV potential, an ACL of 30% is enough to address all the problems without any battery installation. If electromobility is considered, the same value is decreased to 25%. If a PV potential of 150% is considered, the respective values are 52% and 49% for scenarios F5 and F5em respectively. The corresponding values for the total installed battery power per scenario are visualized in Figure 5.20.

If the total installed battery capacity (Figure 5.19) is divided with the total installed battery power (Figure 5.20), we obtain the average battery energy-to-power (E2P) ratio that is depicted in Figure 5.21. For bigger allowable curtailment levels, APC can peak-shave bigger parts of the excess PV infeed and thus, the battery storage is only needed for limited time periods. Consequently, this leads to smaller E2P ratios for the batteries needed to be installed. A steeper decrease in the E2P ratio is observed with bigger allowable curtailment levels.

The APC energy losses that correspond to the four scenarios examined in this section are presented in Figure 5.22. The curtailment losses for the 100% PV potential in case only APC is applied to resolve the technical problems is 2%. The consideration of an additional electromobility load reduces the losses to 1.1%. On the other hand, an increase of 50% in the PV potential brings a significant rise in the curtailment losses. More specifically, the APC losses in case of a PV potential of 150% correspond to 11.7% and 9.2% for the respective no electromobility and electromobility cases.
Figure 5.19: Required installed battery capacity for a varying ACL.

Figure 5.20: Required installed battery power for a varying ACL.
5.4.2 Varying battery price

In all results presented so far, APC is always advantageous to battery storage from a pure economic perspective. Scenario F3 and Scenario F4 with ACL=100% describe the cases where the measure used to address the network problems is exclusively the battery storage and APC respectively. If the costs for these two scenarios (shown in Table 5.4) are compared, a big difference between the battery installation and the APC costs can
be observed. The reason for this difference is the current electricity and battery prices.

In this section a sensitivity analysis with a varying battery price is presented. The purpose of this analysis is to give answers to the question: “How much battery price reduction is needed in order for the batteries to be competitive to APC from a pure DSO perspective?” The results of this sensitivity analysis are shown in Figure 5.23. The current battery cost per installed kWh is denoted with $Cost_B$. Up to a battery price decrease of 7 times, APC is the measure chosen by the optimizer to deal with the network constraint violations. A small battery of 200 kWh is installed for battery price reductions greater than 7, while a battery price reduction of more than 70 times is needed in order to get almost the full battery capacity that is installed in scenario F3 with no APC allowed. The installed battery capacity increase is done step-wise due to the economies of scale. An increase of the electricity price would result in a more expensive APC and would have the same impact as the declining battery prices that are investigated in this case.

5.4.3 Varying PV potential

In this section the effect of a varying PV potential for different load demand scenarios is analyzed through a sensitivity analysis. In Figures 5.24 and 5.25 the installed battery capacity for different PV potential and load demand combinations is visualized. In Figure 5.26 a magnified version of Figure 5.25 for a PV potential smaller than 100% is shown.
**Figure 5.24:** Installed battery capacity for different PV potential and load demand combinations.

A PV potential of 200% with the current load demand would require a total installed battery capacity of 25MWh, a value almost 6 times larger than the one for 100% PV potential. If double the load demand is assumed, this value is reduced to 18.58 MWh. In the no-PV penetration scenarios, a battery of up to 0.83 MWh is required for the 200% load demand case, in order to address the constraint violations during the maximum loading day of winter. As it is shown in Figure 5.26, a minimum PV potential of 70% is needed to create technical problems to the network, and thus necessitate the installation of battery storage.
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Figure 5.25: Installed battery capacity for different PV potential and load demand combinations.

Figure 5.26: Magnified version of Figure 5.25 for PV potential smaller than 100%.
Chapter 6

Conclusion

In this thesis, an optimization tool for the assessment of optimal battery sizing and placement to increase the PV hosting capacity of LV distribution grids was developed. Hybrid AC / DC OPF methods were developed to address the computational challenges that a network of realistic size brings. The performance of the existing and the hybrid OPF methods was evaluated on a benchmark network of reduced size. The most suitable method in terms of computational speed and accuracy was chosen for implementation on the full case study network. As a case study a real LV network of the city of Zurich was chosen and various scenarios were investigated. The effect of PV active power curtailment and electromobility on the total required battery capacity was also examined. The most important conclusions of this work are summarized in this chapter.

- A full AC OPF problem is intractable in practice. On the other hand, if the simplified DC OPF formulation is used, the network voltage profile is disregarded.

- Two hybrid AC / DC OPF methods were developed in this thesis, to render the problem tractable and account for voltage constraints. The performance of the two hybrid methods was tested on a benchmark network of reduced size with a considerable computation time reduction compared to the full AC OPF formulation. Additionally, the battery allocation obtained by the hybrid methods is very close to the one obtained by the benchmark AC method. More specifically, a computation time reduction of 69% and 96% can be achieved with Method a and Method b, respectively. The differences of the normalized 1-norms of the resulting battery capacity allocation between the examined methods and the benchmark AC method is 9.4% and 7.5% for method a and method b, respectively. The corresponding value for the DC method is 52.7%.

- A real distribution network consisting of 254 nodes and located in the periphery of the city of Zurich was chosen for the demonstration of the optimization method. The results of the optimization showed that to exploit the full PV potential, the DSO has to bear a considerable cost in order to address all the technical constraint violations exclusively by installing battery storage devices. More specifically, a
total installed battery capacity of 3.7 MWh with an associated cost of 3 million CHF is required.

- The application of even low allowable curtailment levels can reduce the required installed battery capacity significantly. In case an ACL of 10% is assumed, a reduction of 43% and 50% in the installed battery capacity needs and in the resulting costs is observed, respectively. In this case, the yearly energy losses correspond to 0.5% of the yearly potential PV yield. The installed battery capacity resolves the violation of technical constraints during the largest part of the year, while APC is only applied during the most critical time periods.

- An ACL of 30% is enough to resolve all the technical constraints violation for the case study network without any battery installation. In case an ACL of 100% is applied, the majority of the nodes present a maximum APC level between 20% and 40% while the total energy losses amount to 2% of the yearly potential PV energy yield. If an electricity price of 100 CHF / MWh is considered, the total curtailment cost for an assumed battery lifetime of 15 years is 90 kCHF.

- The impact of an introduction of high shares of electric vehicles was investigated in this thesis. The electromobility load introduces an additional electricity demand for the vehicles charging during the PV infeed hours. As a result, part of the excess PV production is used to serve the additional electromobility load and the installed battery capacity needs are hence reduced. In this case, the required installed battery capacity is 30% lower than in the case without any electromobility load, while a reduction of 33% is observed in the total battery installation cost.

- An increase in the PV potential by 50% results in an increase of 250% in the total installed battery capacity needs. On the other hand, if APC is the only option, the yearly APC losses rise from 2% in case of 100% PV potential up to 12% in case of 150% PV potential.

- The optimal battery dispatch was assessed by a second optimization algorithm that aims to maximize the LV grid’s degree of self-sufficiency. The installation of the batteries resulted in a self-sufficiency increase from 38% to 56%.

- In order for battery storage to be economically competitive to APC from a pure DSO perspective, a drastic battery price decrease is needed. Since the constraint violations appear only for a limited time during the year, the utilization of the battery for other services during the rest of the year, such as participation in the energy and/or reserves market and maximization of self-consumption could render this solution economically more attractive.
Chapter 7

Outlook

The main research objective of this thesis was to assess the cost-optimal placement and sizing of a battery storage system in order to integrate the full PV potential of a LV grid without any violation of technical constraints. The application of this optimization algorithm on a network of realistic size necessitated the use of certain heuristics in order to render the problem tractable. Additionally, co-operation schemes between battery storage, active power curtailment and electromobility were also investigated. Further research on this subject could go along two directions: First, further improving of the solution and computation time and second, comparing more PV integration measures and considering additional concurrent battery services.

Specifically, potential topics for further research are:

- Different heuristics such as genetic algorithms could be applied in order to improve the solution obtained by Method b. A simplification of the network to a lumped 1-node model could drastically accelerate the convergence of the algorithm while enabling the simulation of much bigger time periods, in case transformer overloading is the only problem of the network.

- Apart from battery storage and active power curtailment, other PV integration measures such as conventional network expansion, reactive power control, OLTC transformers and demand response could be investigated in a unified optimization approach.

- The effect of additional battery services such as participation in the electricity and/or reserves market could have a significant effect in the economic viability of a battery investment. These services could be integrated in the objective function of the optimal battery dispatch problem.

- The optimization tool that was developed in this thesis deals with the technical challenges that a considerable PV penetration brings to the distribution grid. However the effect that PV penetration on the LV level has on the MV and HV level of the electricity network of Zurich has not been studied in this thesis.
Appendices
Appendix A

Benchmark network

Battery allocation graphs for the benchmark network.

- Figure A.1: Battery placement and sizing for scenario B3 with the AC method.
- Figure A.2: Battery placement and sizing for scenario B3 with the DC method.
- Figure A.3: Battery placement and sizing for scenario B3 with Method a.
- Figure A.4: Battery placement and sizing for scenario B3 with Method b.
Figure A.1: Battery placement and sizing for scenario B3 with the AC method.
Figure A.2: Battery placement and sizing for scenario B3 with the DC method.
Figure A.3: Battery placement and sizing for scenario B3 with Method a.
Figure A.4: Battery placement and sizing for scenario B3 with Method b.
Appendix B

Case study: Hüslibachstrasse

Battery allocation graphs for the full Hüslibachstrasse network.

- Figure B.1: Battery placement and sizing for scenario F3.
- Figure B.2: Battery placement and sizing for scenario F3em.
- Figure B.3: Battery placement and sizing for scenario F4 with ACL=10%.
- Figure B.4: Yearly cutailed energy and maximum curtailment level per node for scenario F4 with ACL=100%.
- Figure B.5: Battery placement and sizing for scenario F5 with ACL=0%.
- Figure B.6: Battery placement and sizing for scenario F3 without economies of scale considered.
- Figure B.7: Battery placement and sizing for scenario F3 without the thermal constraints considered.
Figure B.1: Battery placement and sizing for scenario F3.
APPENDIX B. CASE STUDY: HÜSLIBACHSTRASSE

Figure B.2: Battery placement and sizing for scenario F3 with electromobility load.
APPENDIX B. CASE STUDY: HÜSLIBACHSTRASSE

<table>
<thead>
<tr>
<th>Node</th>
<th>Installed Capacity (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>0.05</td>
</tr>
<tr>
<td></td>
<td>0.1</td>
</tr>
<tr>
<td></td>
<td>0.15</td>
</tr>
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<td></td>
<td>0.2</td>
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<td></td>
<td>0.25</td>
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<tr>
<td></td>
<td>0.3</td>
</tr>
<tr>
<td></td>
<td>0.95</td>
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Figure B.3: Battery placement and sizing for scenario F4 with ACL=10%.
Figure B.4: Yearly curtailed energy and maximum curtailment level per node for scenario F4 with ACL=100%.
APPENDIX B. CASE STUDY: HÜSLIBACHSTRASSE

Figure B.5: Battery placement and sizing for scenario E5 with ACL=0%.
Figure B.6: Battery placement and sizing for scenario F3 without economies of scale taken into account.
Figure B.7: Battery placement and sizing for scenario F3 without economies of scale taken into account.
Bibliography


[34] I. Buchmann, “How to prolong lithium-based batteries,” tech. rep., Battery University.


