Economic Optimization of Electricity Supply Security in Light of the Interplay Between TSO and DSO

Jacob Tran, Reinhard Madlener and Alexander Fuchs

December 2016
Revised May 2017
Economic Optimization of Electricity Supply Security in Light of the Interplay Between TSO and DSO

December 2016
Revised May 2017

Authors’ addresses:

Jacob Tran
RWTH Aachen University
Templergraben 55
52056 Aachen, Germany
E-Mail: Jacob.Tran@rwth-aachen.de

Reinhard Madlener
Institute for Future Energy Consumer Needs and Behavior (FCN)
School of Business and Economics / E.ON Energy Research Center
RWTH Aachen University
Mathieustrasse 10
52074 Aachen, Germany
E-Mail: RMadlener@eonerc.rwth-aachen.de

Alexander Fuchs
Research Center for Energy Networks (FEN)
ETH Zurich
Rämistrasse 101
8092 Zurich, Switzerland
E-Mail: fuchs@fen.ethz.ch
Economic optimization of electricity supply security in light of the interplay between TSO and DSO

Jacob Tran
RWTH Aachen University, Templergraben 55, 52056 Aachen, Germany

Reinhard Madlener
Institute for Future Energy Consumer Needs and Behavior (FCN), School of Business and Economics / E.ON Energy Research Center, RWTH Aachen University, Mathieustrasse 10, 52074 Aachen, Germany

Alexander Fuchs
Research Center for Energy Networks (FEN), ETH Zurich, Rämistrasse 101, 8092 Zurich, Switzerland

December 2016, Revised May 2017

Abstract

In this paper, the cooperation between Transmission System Operator (TSO) and Distribution System Operator (DSO) for power balancing of the transmission system is simulated, whereby an exemplary grid situation is simulated. Based on the model, an optimization problem is formulated for the utilization of flexible demand and generation. The objective of this study is the economically optimal usage of flexibilities in consideration of the known grid constraints. For this purpose, two optimization problems are being presented: the optimal deployment of flexibilities for the support of redispatch measures and the optimal application of the available flexible units as secondary reserve product in the given ancillary services scheme. In order to discuss different grid types, technical changes, as well as market and price structures, the respective optimization parameters are being defined. For instance, regarding the availability of flexibility units, PV and load profiles need to be analyzed in greater detail. Furthermore, the price sensitive function is shown, revealing fixed flexibility prices and a variable price-demand diagram. Three scenarios are being analyzed, giving examples of typical developments of the communication infrastructure with regard to a stronger TSO and DSO cooperation. The results quantify the potential of flexibilities as redispatch support and secondary reserve product, applying the above mentioned different parameters. We find that using distributed flexibilities is economically not suitable for the application as redispatch support. However, due to the presently high remuneration in the secondary reserve market, the utilization of distributed flexibilities can significantly lower the costs of the TSO operation.

1 Introduction

The development of the European energy systems is moving towards the decommissioning of conventional generating capacities and a substantial demand for the integration of Distributed Renewable Energy Sources (DRES). This goes hand in hand with a more active participation of consumers in participating in Demand Side Response (DSR): consumers have the possibility to control their energy consumption and offer different power system services depending on their necessities and monetary compensation. The increasing utilization of smart grids enables a new degree of freedom in network operation. The new participants and degrees of freedom are necessitating changes in the layout of the distribution grid and are challenging the operation of the network: for example, increased DRES result in higher uncertainty for the generation forecast. Furthermore, electrical flows cannot be considered to be unidirectional anymore
due to more power generation outside of the transmission level. Thus, the complexity of flows requires new considerations to ensure quality and security of the grid. With all these changes, a more dynamic system based on distributed and variable generation may replace the traditional static system, which is based on predictable and centralized power generation. This new situation creates new challenges for both TSO and DSO in order to accomplish the quality and security of the grid. As a consequence, discussions arise on using the distribution grid flexibilities for the overall benefit of the power systems in terms of security-related and economic aspects. Therefore, TSO and DSO need to reinforce their collaboration in order to provide a technical and a market framework, which enable the potential of these flexibilities to be reaped.

This study is based on the electric grid of a part of the city of Zurich, embedded in the Swiss transmission system. The goal of our study is to achieve an economic optimization of the security of supply by using flexibilities for providing active power support to the TSO. We investigate the extent to which flexibilities improve the network operation by, firstly, supporting redispatch measures and, secondly, by participating in the secondary reserve market. Therefore, the first step is to define a design for a flexibility market. Based on historical data analysis of dispatch, secondary reserve, investment and operational costs for different flexibilities, a price range is determined for each characteristic flexibility product. The data used is based on the year 2015. In a second step, we determine the optimal operation of a flexibility portfolio for various grid scenarios. These scenarios depict conventional electric grids in contrast to grids with high shares of DRES not only in standard operation but also in critical congestion scenarios. In addition, the degree of communication and grid monitoring between all network agents influences the possible provision of flexibilities. The different key parameters of the simulation scenarios can be categorized as follows: (1) type of the grid model (copperplate vs. real grid), (2) degree of control flexibility (full communication and control coordination vs. no communication and simple decentralized control), and (3) price sensitivity for flexibility assets (fixed flexibility prices vs. variable price-demand curve) (for details see section 4.7).

The results quantify the flexibility potential and the economic improvements in terms of active power balancing for redispatch measurements and secondary reserve in consideration of their own flexibility requirement to guarantee a stable grid operation. This paper shows that the examined low voltage grid, can provide flexibilities that improve the secondary reserve operation in an economical and operational way. Due to the ability to store energy, the investigated flexibility assets can provide the reserve capacity at lower cost compared to the conventional power plants. The resulting profit of the utilization of flexibility assets highly depends on the applied price design.

The remainder of this paper is organized as follows. Section 2 explains necessary information about system balancing and the remuneration of balancing power in the Central European system. In Section 3 we point out the current and future roles of the system operators and introduce the idea of balancing the transmission system with the support of the DSO. The model framework is analyzed in section 4. The structure of the model area and flexible assets are characterized in detail. This model forms the basis for the simulation. Further, Section 4 presents the mathematical formulations of the optimization problems and explains the different parameters. Section 5 contains the results. Section 6 discusses the limitations of the analysis and concludes.

2 Power System Balancing: Principles, Actors and Market

Next to the function of producing energy and operating the grid, there is another essential part in the electricity supply: the load balancing or system balancing. Due to the lack of storing energy, a balance between consumption and generation is a prerequisite for a stable electricity grid and it guarantees a secure supply at a frequency of 50 Hz. Therefore, it is necessary to closely monitor the grid situation and in the
case of an imbalance to adjust the power plant injections. As far as generation is concerned, it has been a relatively simple problem in the past: production of central power plants is largely foreseeable. With the increasing share of renewable energies, calculating the production of electrical energy becomes more and more challenging. Consumption can hardly be predicted accurately. However, it can be estimated by statistical and analytical methods.

2.1 Balance Group System and Balance Energy

For the non-discriminatory assignment of the balance energy costs most European countries are separated in Balance Groups. A Balance Group (BG) is a group of participants in the electricity market established for the purpose of forming a joint metering and billing unit for the national network operator (Waldner, 2010:1314). Every entry and exit point within the control zone must be assigned to a BG. The core of the BG system is the obligation of the Balance Group Manager (BGM) to submit the schedule to the TSOs before the actual electricity supply. The schedule contains all electricity supplies between members of the BG and between other BGs. Ideally, the balance of the control zone is zero: to every import schedule of a BG there exists a corresponding export schedule of another BG. Otherwise, an adjustment of the power plant schedules is requested by the TSO until a balance is achieved. During the supply process the supply and consumption are metered by the grid operators and forwarded to the TSOs. Optimally, all producers and end-consumers are exactly meeting their declaration. In reality, deviations occur which lead to the need for balance energy. These deviations on the energy balances of the individual BGs are determining the distribution of balancing costs according to the ‘polluter pays’ principle (Swissgrid AG, 2008:10).

The cost for intervening in the power plant operation is billed as balance energy. This also includes the cost for control reserve, which is explained in detail in section 2.2. The balance energy price mechanism is a two-price system in which the prices for balance energy are classified according to the direction of the BG. Billing units in surplus (long) receive a credit note, while billing units in deficit (short) are charged (Waldner, 2010:1315). The price trajectory of balance energy in the year 2015 is illustrated in Figure 1. Notice that power plants which provide positive energy, labeled as ‘long’, are not always getting paid. Sometimes the price is negative, which may lead to significant economic losses for the power plant operators. However, power plants which do not produce as much energy as declared in their schedule, labeled as ‘short’, are always charged.

![Price for Balance Energy in 2015](image)

**Figure 1: Price for Balance Energy in 2015**

Source: Own illustration, based on data from Swissgrid AG (2015b)
2.2 Control Reserve Options

As described in the previous section, an imbalance between generation and consumption requires the need for system balancing. Sometimes, the balancing of energy through adjusting the generation of the concerned power plants in the BG is not possible. This can have multiple reasons: the affected power plants have insufficient capacity to provide the necessary energy, or those power plants cannot ramp up/down fast enough in the given time frame. In such an emergency situation, specific power plants which provide reserve power are used.

Reserve power is achieved within the synchronous electricity grid of the Union for the Coordination of the Transmission of Electricity (UCTE) in Europe by a three-stage system: (1) Primary control; (2) Secondary control; (3) Tertiary control.

The different reserve products are distinguished by their technical requirements, level of power, availability, costs, and region. Figure 2 shows the response time of different control reserves. Deviations at the lower voltage levels are aggregated and collectively balanced at the highest level within the entire UCTE area. A distinction is made between positive control reserve (too much energy is taken from the network area) and negative control reserve (the network area generates too much electricity). In a first stage, balance energy is provided through primary control. Primary control is a completely local control measure. The coupling is based on the physical coupling through the global grid frequency, which is directly related to the global power imbalance. 3 GW in total must be reserved by power plants in the European electricity grid (Kamper, 2012:16). The level of reserve for every individual country depends on its energy demand. Only power plants can be considered which are able to provide at least 1 MW of positive and negative power within less than 30 seconds. More details are listed in Tables 1 and 2 (for the case of Switzerland). The control power must be constantly available. The selected power plants hold a part of their nominal power back to increase or decrease the reserved power as needed. Those power plants are also commonly referred to as spinning reserves (Fuchs et al., 2012:13). The primary control is activated fully as soon as the frequency deviation exceeds 200 mHz. The selected power plants adjust their energy output relatively to the frequency deviation. Hence, the primary control allows all remaining utilities of the electricity system to sustain their scheduled energy output by covering the power imbalance completely.

In the case of long-term system imbalances, secondary control is triggered, relieving the primary control reserves which need to be available for new imbalance situations. Within 15 minutes, secondary control reserves are fully activated and the production of the primary control power plants can return to their nominal output. Unlike primary control, secondary control is not coordinated throughout Europe but within each control zone. Each control zone must reserve a certain amount of secondary control and is only responsible for its own imbalances. All power plants which meet the requirements (cf. Tables 1 and 2) for secondary control can apply within a tendering process.

Equivalent to the primary control, secondary control is relieved if the imbalance situation continues.
For that purpose tertiary control is used. In contrast to primary and secondary reserves, tertiary reserves are activated manually. Since tertiary reserves are rarely used, they are often triggered by a phone call.

Table 1: Technical Requirements for Reserve Control in Switzerland

<table>
<thead>
<tr>
<th></th>
<th>Primary control</th>
<th>Secondary control</th>
<th>Tertiary control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum requirement</td>
<td>±10 mHz</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Activation mode</td>
<td>automatic</td>
<td>automatic</td>
<td>manual</td>
</tr>
<tr>
<td>Maximum delay for automated activation (dead time)</td>
<td>-</td>
<td>10 seconds</td>
<td>-</td>
</tr>
<tr>
<td>Activation time</td>
<td>30 seconds</td>
<td>power gradient of 0.5% of the nominal power</td>
<td>15/20 minutes</td>
</tr>
<tr>
<td>Deactivation time</td>
<td>-</td>
<td>power gradient of 0.5% of the nominal power</td>
<td>in accordance with the power plant schedule</td>
</tr>
</tbody>
</table>

Source: Own compilation, based on data from Furrer et al. (2015:21-24)

Table 2: Market Rules for Control Reserve in Switzerland

<table>
<thead>
<tr>
<th></th>
<th>Primary control</th>
<th>Secondary control</th>
<th>Tertiary control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tender period</td>
<td>week</td>
<td>week</td>
<td>1) day</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>2) week</td>
</tr>
<tr>
<td>Tender product</td>
<td>Mon.-Sun./24 h</td>
<td>Mon.-Sun./24 h</td>
<td>1) 24h, 4h-blocks</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>2) 1 product for the whole week</td>
</tr>
<tr>
<td>Tender quantities</td>
<td>71 MW</td>
<td>approx. ±400 MW</td>
<td>approx. +450 MW/ approx. −390 MW</td>
</tr>
<tr>
<td>Type of product</td>
<td>symmetrical power reserve</td>
<td>symmetrical power reserve</td>
<td>asymmetrical power reserve</td>
</tr>
<tr>
<td>Product size and structure</td>
<td>min. ± 1 MW, incremental increase of ± 1 MW</td>
<td>min. ± 5 MW, incremental increase of ± 1 MW</td>
<td>min. +/− 5 MW, incremental increase of ± 1 MW</td>
</tr>
<tr>
<td>Remuneration of power (procurement)</td>
<td>pay as bid (merit order)</td>
<td>pay as bid (merit order)</td>
<td>pay as bid (merit order)</td>
</tr>
<tr>
<td>Remuneration of energy (deployment)</td>
<td>no payment</td>
<td>SwissIX spot price</td>
<td>price according to offer for 4-hour-block</td>
</tr>
</tbody>
</table>

Source: Own compilation, based on data from Furrer et al. (2015:21-24)

2.3 Control Reserve Market

In accordance with the legislative framework of most European countries, the TSO purchases control reserves in a transparent, non-discriminatory and market-based procedure. Power plant operators who want to provide ancillary services can take part in the form of a tender (‘one-sided auction’). The invitations to tender take place daily, weekly, or monthly, depending on the product. Since 2012, the Swiss TSO Swissgrid has merged the tender for primary control with the German TSOs. The power plant operators must not only specify the amount of the bid, but also define whether they want to provide negative or positive control reserve. In the case of primary and secondary control reserve, both directions must be provided.

The method for the remuneration of secondary reserve is quite a controversial matter. In Switzerland, the remuneration is divided into the procurement price and the deployment price. The procurement price
must be specified for a bid. Power plant operators receive the procurement price for reserve power, using it in the case of an emergency. The price is determined in a Pay-As-Bid (PAB) auction. This means that each reserve provider can determine the procurement price independently, according to its own operational costs. There are discussions ongoing whether the PAB method leads to inefficiency in the procurement of control reserve compared to the method with the Market-Clearing Price (MCP). Detailed information on this topic can be found in Müsgens et al. (2014). After the expiry of the tendering, all tenders are sorted based on ascending order of price. This method is known as the Merit-Order Principle (MOP). Beginning with the lowest price, tenders are procured according to the Merit-Order List (MOL) until the reserve demand is fully covered.

In Switzerland, all power plants which are selected via the MOL receive the same price. The price is tied to the SwissIX, the Swiss spot price index for electricity at the European Power Exchange (EPEX).

2.4 Redispatch Measures

Overloads result from excessive current through grid assets, leading to additional heat generation. If the temperature in the asset rises above the projected one, it can lead to insulation deterioration and thus to an increase in short circuit vulnerability. To avoid these thermal overloads, congestion management by the TSO is needed. Various measures are available to alleviate or even avoid congestions by reducing the current or foreseeable overload to below the defined limits. These measures can be preventative or operational (Swissgrid AG, 2014:3). The use of operational measures can be minimized to a large extent by reducing the allocation of Net Transfer Capacity (NTC) or by auctioning of border capacity. However, if despite preventative measures congestions still appear, or if events occur at short notice (\(N-1\) criterion is lost), the TSO is forced to act operationally. One of those operational measures is a redispatch: the grid operator intervenes in the power plant deployment of two power plants at different locations. The production will be decreased in one area to relieve the congestion. To secure the necessary electricity supply, the second power plant increases its production in order to compensate the missing energy injection. A distinction is also made between national and international redispatch. The latter is also referred to as Cross-Border Coordinated Redispatching (CBCR) (Torres and Pestana, 2005:4).

The following information applies only to the Swiss redispatch system. The amount of compensation or remuneration for redispatch applies equally to all power plant operators. There is no difference in the payment method between national and international redispatch. For increasing the power plant output, the average SwissIX hourly rate from the most expensive ten hours of the last week is paid. Figure 3 shows the weekly average spot price over the year 2015. For decreasing the power plant output, the concerned power plants pay 70% of the current SwissIX to Swissgrid if the SwissIX is positive, or they get paid 130% of the SwissIX if the SwissIX is negative. Since they already get fully paid for the energy before they are ordered to decrease their production, a payback of 70% means that they still have an income of 30% of the SwissIX. The same applies for the 130% if the SwissIX is negative.

3 Current and Future Roles of TSO and DSO

With the changing power generation infrastructure, also the roles of the grid operators in high, medium, and low voltage systems need a review. In the traditional scenario, where thermal power plants provide the energy supply and the low voltage grid solely consists of connected loads which consume energy, the management of the power flow is the TSO’s task, whereas the DSO maintains a passive role. The following sections deal with the roles of the system operators today and point out possible changes for future scenarios.
3.1 State-of-the-Art of the DSO and TSO Roles

On the high and medium voltage grid, a high penetration of metering data and the TSO’s effort to monitor the grid enable real-time power-flow management and control. Having a large number of consumers, the monitoring in the higher voltage level is essential for guaranteeing the power flow at all times. In contrast to that, due to the high number of network elements such as transformers and lines in the low voltage system, but lower size of end-consumers, a full monitoring system in the distribution network is neither economical nor easy to achieve. Thus, in the traditional distribution systems, the metering data is reduced to a small subset and is not controlled in real time.

The Council of European Energy Regulators (CEER) represents the regulators of electricity and gas in Europe (CEER - Council of European Energy Regulators, 2015). CEER deals with the changing role of the DSO with regard to the electric systems which are in transition. It points out that future DSOs require new system flexibility services to maintain a secure and high-quality service. Furthermore, it is stated that especially larger distribution systems should show more cooperation with the respective TSO in critical cases such as line congestions. This underlines that, in traditional systems, the DSO typically does not curtail any distributed generators to counteract temporary congestions due to the lack of communication and predefined routines. It is highlighted that there is no systematic exchange of data between DSOs and TSOs in terms of distributed generation. Also, hardly any storage systems and customer demand responses are realized as an ancillary service today. Other than the system-wide frequency deviation, also voltage constraints need to be considered. This constraint is managed locally due to the fact that the voltage changes throughout the system, especially in the case of long distribution lines in rural areas. For this reason, different approaches should be considered, depending on whether the congestion effects another system or only applies in the local transmission or distribution grid. Traditionally, the TSO creates dispatch schedules on the basis of estimations. The forecast typically does not factor in the impact of distributed generators, which might influence the quality of the estimation negatively. This shows that, in future systems, more information on distributed generators is needed at the transmission level to ensure an adequate scheduling.

Already, in several countries, steps have been taken to define a stronger TSO-DSO cooperation. The German network code VDN 2007 (CEER - Council of European Energy Regulators, 2015), for instance, recommends a cascading implementation across the system levels, starting with the transmission system.
The DSO serves as an entity which activates backup utilities on the TSO’s demand. To this end, bilateral contracts exist between TSO and DSO which deal with balancing measures, such as load and generation curtailment. Furthermore, the DSOs, as well as the energy providers, are required to provide all necessary information to the TSO, who manages the overall power transmission.

3.2 Future TSO-DSO Interaction

For future application, the CEER points out that the DSO should be informed when services from the distribution system are needed on the balancing market, as their utilization might result in subsequent constraints at the distribution level. For this, the DSO needs to manage the power flow more dynamically. Parallel to the above-mentioned example, the activation of local distribution ancillary services can also cause changes at the transmission level. Therefore, the DSO is also required to inform the TSO in the case of any utilization of flexibilities. The earlier section discusses the forecasting measures which are undertaken to ensure accurate dispatch scheduling. In some countries (especially those with higher penetration of distributed generation), the DSOs also apply forecasting methodologies for their own control area and pass the schedule on to the next system level.

The reviewed literature addresses the exchange of data as the major difficulty and applies a high priority to identifying the main variables, such as the type of data, at which exchange rates, and concerning which points of the distribution and transmission grids, which need to be defined explicitly (Alves et al., 2015; ENTSO-E, 2015). This approach is essential to ensure that the future TSOs do not suffer a lack of overall system observability, which can finally result in system instability.

3.3 Power Balancing with DSO Support

The study presented here deals with the TSO-DSO cooperation, as is analyzed in the report from 2014 by the ISGAN association (Zegers and Brunner, 2014). The report gives clear definitions for the roles of TSOs and DSOs managing the transmission and distribution grids, respectively. In greater detail, current and future planned measures in terms of system balancing, congestions, line overloading, voltage control, and black-start-resynchronization are being analyzed for several countries. One important point in terms of coordination is the communication between several system parties. The ISGAN report points out that the DSO should apply two communication directions: the communication line to the DSO’s flexibility customers, which should be in real-time resolution, and the one to the corresponding TSO.

In discussions with the involved industrial partners, power balancing with DSO support has been considered to be the most critical and promising area of cooperation. In the following, we describe the existing cooperation of the system operators in several countries as well as the prospective extension of cooperation. Further, the role of the end-consumer for power balancing will be discussed.

For a stable power system, energy supply and demand have to be in balance at all times. Forecast errors in renewable energy sources need to be accounted for in future grid analyses because the high intermittency can require more balancing capacities. The imbalance stemming from unforeseen changes in energy production or load could possibly be reduced by the TSO, using flexibilities of the distribution system. Balancing the power flow in the electric grid is one type of ancillary service typically coordinated by the TSO with large power producers. However, in some cases low-voltage customers can also take part in the balancing process and therefore be contracted for the service. In Belgium, for instance, the DSO is part of the pre-qualification process and communicates metering data to the TSO (Zegers and Brunner, 2014). More detailed information about the cooperation between TSO and DSO for power balancing in prominent exemplary countries is given in Table 3 (Zegers and Brunner, 2014:23-24).
<table>
<thead>
<tr>
<th>Country</th>
<th>Current Interaction</th>
<th>Planned Extension of Cooperation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria/</td>
<td>From a policy and regulatory point of view it is possible that generators and loads connected to the distribution grid act in the balancing market as long as they are pre-qualified. There has been no interaction between TSO and DSO yet.</td>
<td>None.</td>
</tr>
<tr>
<td>Germany</td>
<td></td>
<td>TSO contracts flexibility on a real-time balancing platform (‘bid ladder’).</td>
</tr>
<tr>
<td>Belgium</td>
<td>On the basis of bilateral contracts between all parties, several low voltage customers offer flexibilities to the TSO. Metering data is used to measure the available flexibility, which is then communicated to the TSO.</td>
<td>More transparency for the DSO on actions of grid users. More transparency for the DSO on actions of grid users. Transition to delivery contracts of ancillary services with ‘dynamic profile provider’ characteristics.</td>
</tr>
<tr>
<td>Canada</td>
<td>The TSO is the balancing authority. Production is continuously dispatched in response to demand fluctuations. Low penetration of distributed energy sources except for large-sized wind farms with must-buy contracts.</td>
<td></td>
</tr>
<tr>
<td>France</td>
<td>Balancing happens at the national level. In the case of critical balancing, automatic or manual signals are sent to the market, which generates offers to restore normal operation. Highly critical situations result in automatic load-shedding, which is activated by the DSO.</td>
<td>Current focus on protection standards, power quality assessment, and voltage supports requirements which do not require a strong TSO-DSO interaction.</td>
</tr>
<tr>
<td>Ireland</td>
<td>The TSOs take full responsibility for balancing active power generation and demand on both the transmission and distribution side.</td>
<td>None.</td>
</tr>
<tr>
<td>USA</td>
<td>The TSO manually requests load-shedding, which is performed by the DSO.</td>
<td></td>
</tr>
</tbody>
</table>

Table 3: Overview by Country of Interaction for Balancing the Grid
Under the assumption that there is a cooperation between TSO and DSO with regard to the balancing challenge, an aggregation of flexible customers on the distribution system side is necessary. The resulting flexibility pool needs to pre-qualify by proving that the required availability, reliability, and flexibility are given. The aggregator could be either the TSO, the DSO, or a third party. However, due to the DSO’s knowledge about the grid configuration and its real-time loading, it seems advisable to allocate the aggregator role to the distribution side. The aggregated flexibilities could be batteries and conventional units, as well as capacities of plug-in hybrid electric vehicles (PHEV), curtailable loads, and renewable energy generators. All these utilities can support and act as ancillary service providers.

Typically, a market entry threshold is given with a minimum capacity of several Megawatts. Thus, smaller storage devices and distributed generators are unable to participate individually, which underlines the necessity of aggregation. It is important to note that those flexibilities might not be available at all times due to meteorological and user comfort dependencies. Figure 4 gives an illustration of the TSO as an Ancillary Service Manager having multiple aggregator tasks. The grid domain consists of several flexibilities, such as conventional generators and storage units (larger units), wind farms (medium-sized units), and (plug-in hybrid) electric vehicles, as well as customers with possible demand-side management (small/medium-sized units). The lines within the grid domain illustrate whether the communication happens directly or indirectly. For the effectiveness of this Ancillary Service Manager, both its communication structure with underlying aggregating entities and the employed optimization setup are key factors. The communication can be realized by using the Internet, GPRS, or Power Line (ripple control) systems (Ulbig, 2014:88).

Figure 4: Exemplary Flexibilities Under the Control of the Aggregator

Source: Own illustration, based on Ulbig (2014:88)

The power-balancing process described in this paper is based on the cooperation with the TSO Swissgrid, the DSO EWZ, and Tiko as an aggregator (see Fig. 5). Swissgrid generates the energy amount request as input to quantify the power support which needs to be realized. Also, the provision for the system support through flexibilities is remunerated by Swissgrid in this exemplary process. The joint analysis which is undertaken from the four parties: TSO, DSO, aggregator and flexibility provider is labeled as the ‘Optimization of Flexibility Coordination’. Additionally to the TSO’s analysis, the DSO manages the grid configuration at the distribution level and serves as a monitoring entity for the load in the system. The outcome determines the receiving provision for the DSO. Thirdly, it is defined that the aggregator monitors its flexibility customers and updates the power schedule for the flexibility provision on a rolling basis. Therefore, also parts of the provision (remuneration) are allocated to the aggregator, in cases where the aggregator is different from the DSO, as presented in this paper. Finally, the Flex-Pool is the party in which a set of flexibility units (storage devices, loads, etc.) is aggregated. The Pool provides the flexibility service into the grid in the form of the earlier explained areas of system support. For the
flex coordination, the flex pool is required to declare the amount and type of flexibility. The aggregator
distributes the payment to the individual flexibilities.

<table>
<thead>
<tr>
<th>Party</th>
<th>Input</th>
<th>Analysis</th>
<th>Output</th>
</tr>
</thead>
<tbody>
<tr>
<td>Swissgrid</td>
<td>• Request of power demand</td>
<td>Optimize Flex Coordination</td>
<td>• Quantity power support</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Pays provision</td>
</tr>
<tr>
<td>EWZ</td>
<td>• Grid configuration</td>
<td></td>
<td>• Provision</td>
</tr>
<tr>
<td></td>
<td>• Grid load monitoring</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aggregator</td>
<td>• Monitoring of flexible customers</td>
<td></td>
<td>• Power schedule for flexibilities</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Provision</td>
</tr>
<tr>
<td>Flex-Pool</td>
<td>• Provides flex capacity</td>
<td></td>
<td>• Provision</td>
</tr>
</tbody>
</table>

Figure 5: Structure of the Proposed Power Balance Process

4 The Models

The optimization method for the utilization of distributed flexibilities for power balancing consists of
three parts. An overview of the method is given in Figure 6 and has three categories.

- **Source Data:** The historical data of the time series for redispatch measures in Switzerland in
  the year 2015, and the historical data of secondary reserve in Switzerland in the year 2015, are
  included in the model. The objective of the optimization is to achieve an economic improvement in
  a post processing through the use of flexibilities. Further, the first part provides the grid constraints
  for the optimization formulation. With the aim of considering boundaries and constraints of the
  individual flexibilities, the different flexibility assets will be analyzed regarding their level of power
  consumption, technical and operational frameworks, and costs.

- **Simulation & Parameters:** To solve the TSO/DSO coordination problem, a linear optimization
  problem is solved. The maximum optimal usage of flexibilities depends on three different param-
  eters: the level of load and photovoltaic (PV) injection while flexibilities are deployed, the degree
  of communication between all parties involved, and the cost sensitivity of the flexible household
  consumers. An analysis of the results shows the impact of the different parameters.

- **Results:** The results contain the monetary profit and the optimal schedule of the flexibility assets.
The following sections describe the scenario and asset modeling and the grid modeling. Then, two flexibility optimization problems are formulated regarding distributed redispatch support and secondary reserve support.

4.1 Study Area and Modifications

The study area used is based on the grid data provided by the DSO EWZ. A simplified illustration of the grid topology is shown in Figure 7. The grid belongs to the regional distribution system (22 kV) of the area Binz in Zurich. The consideration of the regional distribution system has the advantage of analyzing the industrial consumers and generations connected to the 22 kV level as well as the households in the subjacent low voltage system. The different household areas are summarized as load buses. The technical grid data contain static information about transformers, lines and nodes. Important are the levels of power consumption at all PQ\textsuperscript{1}-buses and the maximum capacity of the lines and transformers. The difference between the maximum capacity and load is decisive for the amount of flexible power deployment.

The grid contains seven household loads, which are connected at different buses. The households are able to provide a part of their energy consumption as flexibility. Further, three types of flexible assets are implemented. Two cooling warehouses, as industrial consumers, one PV power plant, as a distributed generation, and one big size Energy Storage System (ESS) (battery). In the present paper, the grid is modified with an increased load behavior for the low voltage consumers and with an increased level of PV feed-in. Both changes are intended to depict a natural future development of the electric grid of Zurich. These changes allow to assess the grid requirements in terms of quality and security under a simulated tightened grid situation. Additional information on the load and PV modification is provided in the following section 4.2.

\footnote{Load bus defined by real power P and reactive power Q}
4.2 Industrial Consumer and Distributed Generators as Flexibility

The economic dispatch optimization of the power system is usually dictated by the operational costs of the flexible generators, i.e. marginal costs, opportunity costs, ramping costs as well as start/stop costs. However, a novel approach is to use industrial energy storage units for flexibility purposes. Here, the costs are dictated by the losses in the process of storing and releasing electrical energy. In the following, the cooling warehouse (as an example for an industrial energy consumer), the battery storage, and the PV generator are analyzed.

4.2.1 Cooling Warehouse

Thermal systems can be used as a storage for energy. As long as the actual temperature is within the permitted technical framework, electrical energy can be deployed through the control of thermal energy charge and discharge, respectively. In the research project ‘Flexlast’ (Berner et al., 2014), the use of big industrial cooling assets for control reserve was investigated. The idea is that the cooling warehouse provides positive reserve capacity through down-regulation and negative reserve capacity through up-regulation. In the case of the investigated cooling warehouse, the desired temperature is between $-30\,^\circ C$ and $-26\,^\circ C$. Total power consumption depends on the number of cooling compressors. Typical values range between 0 kW and 1500 kW (Berner et al., 2014:26-32).

Figure 8 compares the forecast and the actually measured load profile of a cooling compressor. The black line, which represents the objective load profile, shows the time frame in which the compressor can be deployed for positive flexibility purposes. Determining for the amount of available flexibility is the cumulative energy supply of the cooling warehouse. Every cooling compressor has a minimal and maximal operating time. The desired temperature of the warehouse must not be violated. In addition, the weather and the incoming goods restrict the usage of flexibility. However, a cooling house consists of multiple units with different cooling schedules. The cooling schedules are shifted, so that the total load profile over the day is ideally a smoothed curve. For our study, the deployment of cooling assets is simplified. Since the overall load profile is nearly constant, there is no temporal restriction for the deployment. This also means that the weather and the income of goods are neglected. As mentioned above, the cooling warehouse provides energy through down- or up-regulation of the compressors. This means that
the warehouse temperature is increasing or decreasing, respectively. To return the temperature to its initial state, the compressors must be activated or deactivated after every flexibility support measure. This process is commonly described as load-shifting. Because of inefficiency of the compressors and the cooling losses of the warehouse isolation, load-shifting causes a higher energy consumption compared to the normal operation of the warehouse. The costs for the additionally consumed energy represents the costs for the warehouse operator to take part in the flexibility market. The general assumption in our study is that providing flexibility for one hour leads to a temperature change of $\Delta 1 \, ^\circ C$. This eventually causes an additional energy consumption of 5% to 10% of the cooling unit power level to restore the initial temperature (Berner et al., 2014). The energy price for industrial consumers is in most cases arranged via bilateral contracts with the local energy supplier. The price can vary depending on the day of the week, and the time of the day. For practical calculations, the average energy price for industrial consumers in the year 2016 is set as the reference value for energy costs (Ind, 2015)$^2$. Thus, the marginal costs for the warehouse operator to provide 1 MWh of flexibility are:

$$c_{\text{cooling}} = P^\text{flex} \cdot T \cdot \eta_{\text{loss}} \cdot c_{\text{energy}}$$

$$= 1 \, \text{MW} \cdot 1 \, \text{h} \cdot 10\% \cdot 195 \, \text{€/MWh}$$

$$= 19.5 \, \text{€}.$$ 

The contribution margin for cooling warehouse operators results as the difference between the received revenue for the flexibility support and the marginal costs (see Figure 9). As an incentive for the operators to take part in the flexibility market, the contribution margin must reach at least a positive level.
4.2.2 PV Power Plant

Active power control of renewable generation refers to the adjustment of the resource’s power production. PV installations have the technical capability of providing a fast response to regulation signals. By curtailing the power production, PV power plants can provide negative power support (down-regulation). Using these kinds of flexibility has been acknowledged and been available for several years. However, these approaches have not yet been proven in the real grid operation (Gevorgian and O’Neill, 2014:85). There are several challenges to implementing greater flexible renewable power plants. On the one hand, the stochastic nature of the power generation leads to uncertainty in the planning process. On the other hand, regulations (i.e. Germany: Erneuerbare-Energie-Gesetz, BDEW - Bundesverband der Energie- und Wasserwirtschaft, 2012) often impose significant barriers to the curtailment of DRES.

The share of solar generation in Switzerland has increased over the last years. In 2014, installed solar capacity totaled around 1,076 MW, which is about 2% of the domestic electricity demand (Bundesamt für Energie, 2014:3-5). Coinciding with this growth, the price for solar systems has been declining by more than 50% since 2009 (Gevorgian and O’Neill, 2014:1). The largest Swiss PV power plant has a capacity of 6 MW. The size of this power plant is taken as an example in the model. Due to the fact that the power output is dependent on solar irradiation, the implemented PV power plant in the model is only able to provide negative power support. The maximum amount of power is also depending on the solar irradiation, which is represented through the variable $\lambda_{PV}$ (cf. Section 4.7.2). Due to marginal costs of zero, the PV power plant can be used as a cost-effective ancillary service (Papaefthymiou et al., 2014:20). The flexibility utilization costs are simply the loss of profit through down-regulating of the power plant. The profit corresponds approximately to the energy spot price. Therefore, the opportunity costs are defined by the SwissIX energy price:

$$c_{pv} = c_{SwissIX} \cdot (2)$$

4.2.3 Battery Storage

Energy Storage Systems are one of the most complex and challenging issues in the energy industry. There are a number of electric storage technologies, including batteries, Superconducting Magnetic Energy Storage (SMES) units or super-capacitors. One of the most important of these is battery storage. With its use in electric vehicle devices and as storage units for renewable generation, the need for efficient battery storage has emerged rapidly. For short-term requirements, battery storage can be used to support frequency control in the grid. For long-term requirements, battery storage units are applied for energy management and reserves (Joseph and Shahidehpour, 2006:1-2). Due to advances in the production of battery technologies as well as the improvement in the cycle life-time, the global installed grid-connected battery power has increased from 120 MW to 690 MW in the last years (Koller et al., 2016:2). There are ongoing discussions on how to use these capacities for ancillary services, such as frequency control by the TSOs. In Europe, for instance, the TSOs of Germany, Austria, the Netherlands, and Switzerland have started to analyze the harmonization of prequalification rules for units with limited storage capacity (such as batteries). This might provide the opportunity for large-sized ESS to interact in the frequency control reserve market.

In cooperation with the technology manufacturer ABB (ABB, 2016) and the cantonal energy supplier EKZ (EKZ, 2016), a battery storage system with a power of 1 MW was implemented in the electric grid of Zurich. The system is pre-qualified and used to provide primary control reserve. Thus, it is the first Swiss non-hydro power plant providing primary control. In contrast to conventional hydro power plants, the battery storage unit is fairly small. However, it has a really fast response time and can switch from charging to discharging mode (and vice versa) within a few seconds (Koller and Völlmin, 2013:2-4). This
corresponds to the increasing demand for fast and small control reserve.

The marginal cost of the utilization of the battery is dependent on the energy cost \( c_{\text{energy}} \), the charge efficiency \( \eta_{\text{load}} \), the discharge efficiency \( \eta_{\text{gen}} \), and the cost of degradation \( c_{\text{deg}} \). In theory, the mechanism of a battery should work forever, but cycling, temperature, and aging decrease the performance over time. Batteries degrade progressively with reduced capacity and cycle life (Forman et al., 2012:3). \( c_{\text{deg}} \) represents the degradation costs for charging or discharging the battery once with 1 MWh. The battery is charged and discharged during the flexibility support process. Therefore, the degradation costs must be considered two times (eq. (3)). The technical values of the battery are taken from Fortenbacher et al. (2014:3-7). The energy price is the average price for industrial consumers in the year 2016 without VAT. The investment costs of the assets are neglected.

\[
c_{\text{battery}} = c_{\text{energy}} \cdot (1 - (\eta_{\text{load}} \cdot \eta_{\text{gen}})) + 2 \cdot c_{\text{deg}}
\]

\[
= 195 \, €/MWh \cdot (1 - (0.98 \cdot 0.97)) + 13 \, €/MWh
\]

\[
= 21.63 \, €/MWh.
\]

Table 4 provides an overview of the implemented flexibility assets in the model. In our study, the utilization of emergency diesel generators has been analyzed. The current laws for the operation of these diesel generators limit the usage to 30 h per year. In addition, the usage is non-economical due to its high marginal costs. The operational costs of the diesel generator is dependent on the price for the fuel.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Cooling Warehouse</td>
<td>19.5</td>
<td>0.85</td>
<td>1.20</td>
<td>3.4 (negative) 5 (positive)</td>
</tr>
<tr>
<td>PV Power Plant</td>
<td>SwissIX</td>
<td>6</td>
<td>0</td>
<td>-</td>
</tr>
<tr>
<td>Battery Storage</td>
<td>21.63</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td>Diesel Generator</td>
<td>74.88</td>
<td>0</td>
<td>1.5</td>
<td>30 (per annum)</td>
</tr>
</tbody>
</table>

### 4.3 Flexibility Potential in Households

In the household sector, flexibility can be achieved especially through demand management of power consumption, such as heating and cooling cycles. Typical flexible household devices can be e.g. electric vehicles (EV), heat pumps, air conditioners, PV storage systems, or even washing machines (Uhrig et al., 2016:3). The advantage of those kinds of flexibilities is that they can react really fast and provide the necessary power within less than a minute (Papaefthymiou et al., 2014:22-24). The potentials are very high, but the immaturity of this technology, and the missing IT and communication structure, present a significant challenge.

Uhrig et al. (2016) have analyzed and quantified the potential of private households for the utilization as flexibility. The devices with the greatest potential are the EV, the heating system, and the PV storage. This study is taken as a reference for the household modeling in this paper. In the following, the different devices considered are described in more detail.
4.3.1 Electric Vehicle

EVs make use of stored energy in the vehicle’s battery. The vehicle can be selectively charged or discharged by the grid when it is not used and parked at a charging spot. A distinction between two key operational modes can be made (Papaefthymiou et al., 2014:23):

1. G2V (Grid-to-Vehicle): the EV is operated as a DSR option, which means that the charging time can be shifted.
2. V2G (Vehicle-to-Grid): in addition to charging (negative power) the battery of the EV can feed power (positive power) into the grid.

Due to its primary use as a means of transportation, the use of an EV as a flexibility option is both limited and uncertain. However, it is highly available during the evening and over night. During the day, its availability depends on whether the vehicle is connected to the grid via a charging infrastructure. Figure 10 shows the typical average load profile of an EV. The vehicle is connected to the grid from 5 pm to 8 am the next morning. In that time it can recharge up to 10 kWh. The upper limit shows the case where it is connected with maximum power to the grid. The lower limit results from unloading the EV down to a 30% state-of-charge and an as-late-as-possible recharging cycle shortly before the next departure. Between both limits, the vehicle can be frequently charged and discharged. The objective profile corresponds to the uncontrolled charging process after arrival of the EV. The car charges with 3.7 kW and is fully loaded at around 9 pm. Theoretically, providing positive flexibility during the night hours is possible.

![Figure 10: Illustration of the Cumulative Electric Vehicle Energy Demand with Upper and Lower Limits for Flexibility Utilization](Image)

Source: Uhrig et al. (2016:8)

Key advantages of this concept are the development and the maturity of this technology. EVs are a very prominent social topic and the investment into the infrastructure is driven by the transportation sector. However, there is low experience with the integration of EV fleets into the existing power system.

4.3.2 Power-to-Heat

There are several forms of heating systems for household use. In the past, the majority of the residential heating technologies were driven by fossil fuels and especially gas or oil. Nowadays, the common electric heating systems allow the consumers to store or shift the heating process for later use. Thermal energy can be relatively efficiently stored in a number of ways. The most common one is the hot-water tank. The heat from the storage can be used by the end consumer, and the cost of flexibility is mostly due to isolation losses. Another efficient technology is the heat pump. It effectively moves heat energy from a source of heat to the storage or directly to the end-user. The combination of thermal storage with electric heating has a huge potential to increase the flexibility of the power grid.

Flexibility is mainly provided through the change of the temperature set point (Uhrig et al., 2016:9). To provide positive power, the temperature is decreased within a specific limit. Thus, to provide negative power, the set point is increased. Since the demand for heat is strongly seasonal, the flexibility potential is
lower in the summer and higher in the winter (80% of the yearly flexibility potential occurs in the winter months). Figure 11 shows the relation between the temperature, the energy level of the heat pump, and the load status of the hot-water tank.

![Figure 11: Illustration of the Utilization of Household Heating Systems for Flexibility Purposes. Source: Uhrig et al. (2016:10)](image)

### 4.3.3 Flexibility Potential and Costs

The grid data in our study provides only a limited insight on the household sector. Based on Uhrig et al. (2016); Papaefthymiou et al. (2014), and interviews with representatives of the DSO EWZ, a maximum flexibility potential of 15% of household power consumption was estimated (see eq. (4)). Seasonal effects are neglected, but can be easily added to the model. The household energy consumption varies depending on the time of day (see variable $\lambda_{load}$ in Section 4.7.2).

The costs of the utilization can only be roughly estimated. Primarily decisive are the costs for the heating systems, since that part provides the biggest share of the household potential so far. In this paper, the flexibility utilization causes a loss of 10%. The cost for energy varies over the year.

$$P_{\text{max household}} = 15\% \cdot P_{\text{demand}}$$

For simplification purposes, the average energy costs of a private customer in the year 2015 are used as the energy costs here, i.e.

$$c_{\text{Household}} = c_{\text{energy}} \cdot \eta_{loss}$$

$$= 217.60 \text{€}/\text{MWh} \cdot 10\%$$

$$= 21.76 \text{€}/\text{MWh}.$$  

### 4.4 The DC Power Flow Model

The economic optimization of power system networks is generally known as Optimal Power Flow (OPF). This section explains the derivation of the network equations.

In a network with $n$ buses, the impedance elements of the whole system are incorporated into an $n \times n$ bus admittance matrix $Y_{bus}$. It relates the nodal current injection $I_{bus}$ to the node voltages $V_{bus}$.
The non-linear AC-network equation is:

\[ I_{bus} = Y_{bus} \cdot V_{bus} \]  \hspace{1cm} (6)

with

\[ S_{bus,i} = P_{bus,i} + j \cdot Q_{bus,i} = V_{bus,i} \cdot I_{bus,i}^* \]  \hspace{1cm} (7)

and

\[ P_{bus,i} = \text{real}(S_{bus,i}) = \text{real}(V_{bus,i} \cdot I_{bus,i}^*) . \]  \hspace{1cm} (8)

The asterisk denotes the complex-conjugation of the variable. For this paper, the Direct Current (DC) power flow model is used (Machowski et al., 2008). Since the focus is on using active power for supporting measures, the complex parts of current and voltage are neglected. For the DC-power flow approximation four assumptions are used: \( V_{bus} \) has magnitude 1, \( Q_{bus} \) is zero, the real part of \( Y_{bus} \) is neglected, and the angular difference of the bus voltage angles \( \theta_i - \theta_j \) are sufficiently small, so that \( \sin(\theta_i - \theta_j) \approx \theta_i - \theta_j \).

The Alternating Current (AC) OPF equations can be linearized to give the DC power flow network equations:

\[ B_{bus,dc} \cdot \vec{\theta} = \vec{P}_{gen} - \vec{P}_{demand} . \]  \hspace{1cm} (9)

The vector of bus voltage angles \( \vec{\theta} \) consists of the set of voltage angles at non-reference buses. \( \vec{P}_{dc} \) is the sum of all generations and loads connected to the bus. Generations are declared as positive power, while loads are declared as negative power. The branch flows in the grid are dependent on the bus injection (power plant injection and energy consumption, respectively), the grid topology and the admittances, i.e.

\[ \vec{P}_{branch,dc} = B_{branch,dc} \cdot \vec{\theta} . \]  \hspace{1cm} (10)

The power flow can be solved by calculating the voltage angles in the linear equations (cf. eq. (9)). The angle of the reference node (often the slack bus) is set to 0 for the calculation. The branch flows and slack bus generator injection are then calculated directly from the bus angles.

### 4.5 Flexibility for Redispatch Support

In the future, network congestion management for relieving bottlenecks in the transmission system can be supported through load control, using connected storage units, and controlling the power of decentralized generation. Technically, this form of ancillary service can be interpreted as an active power exchange at the interconnection between transmission and distribution system. The task of the DSO and aggregator is the coordination between the affected interfaces. Those interfaces can be within the distribution grid or at the border to the transmission grid. Since the concerned congestions are identified a day ahead, it is technically not challenging to provide this kind of ancillary services. The first scenario model is to simulate the engagement of flexibilities, provided through the distribution system, to support or replace redispatch measures at the transmission system. The aim is to achieve an economic improvement through the use of flexibilities without violating technical limitations of the grid.

#### 4.5.1 Redispatch Data

For obtaining a realistic assessment of flexibilities supporting the above-mentioned redispatch measures, the redispatch deployment of the year 2015 is used in the model. The historical redispatch data are
provided by Swissgrid. The data contains a list of all redispatch events carried out in 2015. In particular, the exact period of time, the volume of power transferred, the affected power plants and the reason for the redispatch are listed. It may occur that there are multiple entries in the list recorded, having the same cause. Therefore, all entries noted with the same reason, date, and time are pooled to one event. The power volume of the individual events are summarized. The result is taken as the power volume for the new event. All pooled redispatch events in 2015 are illustrated in Figure 12.

![Figure 12: Volume of the National and International Redispatch Measures in 2015 [MWh]](source: Own illustration, data based on Swissgrid AG (2015a))

### 4.5.2 Formulation of the Optimization Problem for Redispatch Support

The optimal redispatch model is implemented in MATLAB. The physical grid is considered by power flow equations in the constraints of the problem formulation. The optimization problem is formulated as a linear function, which is eventually solved with the Gurobi Solver. The objective is to reduce the overall costs for redispatch measures by deploying available flexibilities, which can possibly provide energy at lower costs than the conventional hydro power generation. The objective function (eq. (11)) totals the cost of energy of all flexible assets ($P_{\text{flex}}^t$) and hydro plants ($P_{\text{hydro}}^t$). Here, the sum of all assets must exactly comply with the redispatch demand ($P_{\text{demand}}^t$) at all redispatch events $t$ (cf. eq. (15(a))). Notice that in case no flexibility can be deployed, the hydro power generation must be able to fully cover the demand. Thus, the available amount of hydro generation is modeled without upper limits (cf. eq. (15(e))). Further, the objective function also aggregates over all redispatch events. The hydro generation is not included in the power flow equations, since large-scale hydro power plants are usually connected to the transmission or regional distribution system and, therefore, have no impact on the utilization of flexible assets.

Typically, the assets presented in this study have a limited capacity. The battery storage unit for example, must be re- or discharged after every single use. This would mean that the problem formulation is time-coupled. However, the redispatch events occasionally happen over the period of one year and, in addition, are spread out from each other. Therefore, the consideration of a time-decoupled formulation can be made here; $c_{\text{flex}}^t$ are the asset marginal costs according to Table 4.

$$\min \sum_{t=1}^{N_t} \sum_{i=1}^{N_{\text{flex}}^t} P_{\text{flex}}^t \cdot 1h \cdot c_{\text{flex}}^t + P_{\text{hydro}}^t \cdot 1h \cdot c_{\text{hydro}}^t$$

(11)

$$\forall t = 1, 2, ..., N_t, \quad \forall t = 1, 2, ..., N_{\text{flex}}$$

20
subject to
\[
\sum_i P_{\text{flex}}^i + P_{\text{hydro}}^t = P_{\text{redispatch}}^t
\]  
(12(a))

\[
B_{\text{bus,dc}} \cdot \vec{\theta}_t = \vec{P}_{\text{bus}}^t = \vec{P}_t^\text{gen} - \vec{P}_t^\text{demand}
\]  
(12(b))

\[
B_{\text{branch,dc}} \cdot \vec{\theta}_t = \vec{P}_{\text{branch}}^t \leq \vec{P}_{\text{branch}}^{\text{max}}
\]  
(12(c))

\[
0 \leq P_{\text{flex}}^t \leq P_{\text{flex}}^{\text{max}}_i
\]  
(12(d))

\[
0 \leq P_{\text{hydro}}^t
\]  
(12(e))

\[
\theta_{\text{ref}}^t = 0
\]  
(12(f))

The variables in the formulation can be understood as follows: $P_{\text{flex}}^i$ and $P_{\text{hydro}}^t$ are the supplied power of asset $i$ for the redispatch event $t$, $\vec{P}_{\text{bus}}^t$, $\vec{P}_t^\text{gen}$, and $\vec{\theta}_t$ are described in Section 4.4.

The parameters in the formulation are defined as follows: $c_{\text{flex}}^i$ and $c_{\text{hydro}}^t$ are the costs per MWh of using energy for redispatch measures, $P_{\text{demand}}^t$ is the total energy demand of the redispatch at time $t$, and $P_{\text{flex}}^{\text{max}}_i$ is the maximum possible power procurement of asset $i$.

### 4.6 Flexibility for Secondary Reserve Control

Fluctuations in the electric grid are one of the biggest challenges for grid operators. Two important reasons for that are the growing amount of DRES and the deviations from the expected power consumption. However, in both cases only small imbalances occur in the grid. Thus, faster and small-sized control reserve power is needed. Usually, secondary control is used before primary control for smaller imbalances. Primary control is coupled through the European grid frequencies and related to their imbalance. In contrast, secondary reserve is controlled within each control zone and can therefore be more precisely activated (Kamper, 2012:16). It is therefore an interesting idea to use flexibilities for these smaller secondary control demand. Flexible consumptions are often able to quickly adjust their power and can be locally used to clear the imbalances. The second model-based scenario analyzes the optimal use of flexible assets and household electricity consumption for the support of secondary control measures.

#### 4.6.1 Secondary Reserve Data

Analogously to the redispatch scenario model, the secondary reserve model is a post-optimization of the secondary reserve operation in the year 2015. The historical data of all secondary reserve control measures are officially accessible at the Swissgrid website. The information about the control measures is divided into two parts. As described in Section 2.2, the tendering process is dependent on the procurement price, whereas the remuneration for the actually delivered energy is defined by the deployment price. The first part contains a weekly ($t$)-based list about the procured amount of reserve power ($P_{\text{sec-demand},t}$) and the week-related price for 1 MW procurement ($c_{\text{proc}}^t$). Further, the price for deployment (SwissIX electricity spot price) is also given for every week of the year. The second part lists the deployment ratios ($r_{\text{deploy}}_{15 \text{min},t}$) for the whole year. The year is split into 15-min intervals and each ratio stands for one 15-min cycle of the year. The actual power quantity can be calculated through the multiplication of the ratio by the procured power amount of the related week $t$:

\[
P_{\text{deploy}_{15 \text{min},t}} = r_{\text{deploy}_{15 \text{min},t}} \cdot P_{\text{sec-demand},t}.
\]  
(13)

#### 4.6.2 Formulation of the Optimization Problem Secondary Frequency Control Support

The optimization problem formulation of the second model is similar to the one of the first model. Again, the objective is to optimize the operation of secondary reserve control with the support of flexible generation and consumption. However, in this model the variable $t$ does not stand for a secondary reserve
measure, but for the time period of one week. The reason is that the tendering process for secondary reserve is on a weekly basis. The variables \( P_{\text{flex}} \) and \( P_{\text{hydro}} \) are therefore the amount of procured energy per week. The actually deployed energy is described in \( r_{\text{deploy}} \). To relate the ratio to the energy procurement, the time period of the ratio must be adjusted to a weekly basis. For this, the ratios from Monday to Sunday are summed up to \( r_{\text{deploy}} \). The costs are given in € per MWh. Therefore, the ratio must be multiplied by the factor 0.25 to normalize the ratio to an hourly ratio.

\[
\min_x \sum_{t=1}^{N_t} \sum_{i=1}^{N_{\text{flex}}} (P_{\text{flex}} \cdot c_{\text{flex}} \cdot 0.25h \cdot r_{\text{deploy}}^t) + (P_{\text{hydro}} \cdot c_{\text{proc}} \cdot c_{\text{deploy}} \cdot 0.25h \cdot r_{\text{deploy}}^t) \quad (14)
\]

subject to

\[
\forall t = 1, 2, ..., N_t, \quad \forall t = 1, 2, ..., N_{\text{flex}}
\]

\[
\sum_i P_{\text{flex}}^i + P_{\text{hydro}}^i = P_{\text{secondary}}^t \quad (15a)
\]

\[
B_{\text{bus,dc}} \cdot \bar{\theta}_t = \bar{P}_{\text{bus}}^t - \bar{P}_{\text{gen}}^t - \bar{P}_{\text{demand}}^t \quad (15b)
\]

\[
B_{\text{branch,dc}} \cdot \bar{\theta}_t = \bar{P}_{\text{branch}}^t \leq \bar{P}_{\text{max}}^t \quad (15c)
\]

\[
0 \leq P_{\text{flex}}^i \leq P_{\text{flex}}^i,_{\text{max}} \quad (15d)
\]

\[
0 \leq P_{\text{hydro}}^t \quad (15e)
\]

\[
\theta_r^t = 0 \quad (15f)
\]

The variables in the formulation can be understood as follows: \( P_{\text{flex}}^i \) and \( P_{\text{hydro}}^i \) denote the supplied power of asset \( i \) for the redispatch event \( t \), \( \bar{P}_{\text{bus}}^t \), \( \bar{P}_{\text{gen}}^t \), and \( \bar{\theta}_t \) are described in Section 4.4.

The parameters in the formulation are defined as follows: \( c_{\text{flex}}^i \) and \( c_{\text{hydro}}^i \) are the costs per MWh of using energy for redispatch measures, \( c_{\text{proc}}^t \) and \( c_{\text{deploy}}^i \) are the cost per MWh of procuring and deploying secondary reserve at time \( t \), and \( P_{\text{secondary}}^t \) is the total demand of secondary reserve capacity at time \( t \).

### 4.7 Simulation Parameters

This section explains the implemented parameter settings in the optimization model. The different parameters are used to analyze the grid and flexibility operation under various grid and remuneration scenarios. The characteristics of the parameters have an impact on the flexibility utilization and on the system’s economic improvements.

#### 4.7.1 Grid Model: Copperplate vs. DC Load Flow Model

Solving the optimization problem is a fairly simple problem if grid constraints are not considered. This so-called copperplate grid simplification scenario achieves the solution of an economic dispatch (Ulbig, 2014:197). Nonetheless, the optimization goal is still to derive the most efficient operation of the power system. The utilization of flexibility is not restricted to the grid constraint, but only to its economic viability. The grid constraints of the DC power flow model are neglected. The result of the optimization shows the maximum potential of the utilization of flexibilities.

Under the consideration of the grid limits, the power flow must be calculated within the optimization. In comparison to the copperplate scenario the objective is not only to maximize the flexibility utilization, but also to run the grid within its technical limits. This eventually means that the flexibilities are not necessarily operated up to their full potential.
4.7.2 Modification Load and PV Profile

As mentioned in Section 4.1, the total grid load and PV injection are increased in order to simulate the utilization of flexibilities in a tightened grid situation. Since the household flexibility is set as a percentage of the load value (cf. Section 4.3), increased household loads also lead to an increased share of flexibility. The loads are increased proportionally. All changes can be taken from Table 5.

Table 5: Grid Modification: PQ-Buses

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>PQ 14</td>
<td>27.44</td>
<td>42.94</td>
</tr>
<tr>
<td>PQ 25</td>
<td>0.54</td>
<td>0.89</td>
</tr>
<tr>
<td>PQ 26</td>
<td>2.31</td>
<td>3.62</td>
</tr>
<tr>
<td>PQ 27</td>
<td>0.30</td>
<td>0.47</td>
</tr>
<tr>
<td>PQ 28</td>
<td>1.07</td>
<td>1.67</td>
</tr>
<tr>
<td>PQ 31</td>
<td>0.26</td>
<td>0.41</td>
</tr>
<tr>
<td>Sum</td>
<td>31.95</td>
<td>50</td>
</tr>
</tbody>
</table>

While the change for the PQ-buses is constant throughout the simulation, the increase of PV generation is in dependence with the grid situation. At the start of the simulation, the maximum level of PV injection ($P_{PV\ gen,max}$) into the grid is determined within a power flow calculation. Decisive for the maximum level is the quantity of flexibility assets and the household loads in the grid. Depending on the requirements of the grid scenario, the PV generation can then be set as a value that is subject to $P_{PV\ gen,max}$. High PV generation leads to a high penetration of the grid, which results in a lower chance of utilizing flexibility. For our simulation, values between 0.85$P_{PV\ gen,max}$ and 0.92$P_{PV\ gen,max}$ are investigated.

The grid data provide only static information of the grid. However, in reality the loads and the PV generation are changing over the day. On the one hand, a higher household energy consumption can be recorded at midday and in the evening. PV plants, on the other hand, need sunlight for power generation. Usually, the highest generation is measured in the early afternoon. Hence the fluctuation of load and PV generation must be considered in the model as well. Therefore, the variables $\lambda_{load,t}$ and $\lambda_{PV,t}$ are introduced. The variables represent the course of the load and PV generation and are added to the right-hand side of the bus-grid constraint. The course of the two graphs is illustrated in Figure 13. The grid constraints in the problem formulation are modified as follows:

$$B_{bus,dc} \cdot \tilde{\theta}_t = \tilde{P}_{bus} = \tilde{P}_{gen} + \tilde{P}_{PV\ gen,0} \cdot \lambda_{PV,t} - \tilde{P}_{demand,max} \cdot \lambda_{load,t} , \quad (16)$$

where $\tilde{P}_{PV\ gen,0}$ is the vector of the installed PV capacity at full power rating (assumed total grid PV generation depending on $P_{PV\ gen,max}$). The vector contains the PV generation of all buses in the grid. $\tilde{P}_{demand,max}$ is the vector of the maximum initial demand at the buses before the modification.
Figure 13: Value of the Synthetic Load and PV Profile Parametrized Using $\lambda_{PV,t}$ and $\lambda_{load,t}$

### 4.7.3 Cost Sensitivity Function

Section 4.3 introduced the household’s flexibility and quantified the marginal costs for its utilization. Compared to the industrial load schedule, the consumer consumption is inherently uncertain. In addition, the willingness to participate in DSR differs among households. The implementation of a fixed price, where all households are able and willing to provide flexibility, is rather inaccurate. Therefore, a cost sensitivity function is implemented in the model as an alternative to the marginal cost concept. Figure 14 shows the course of the function, which is based on the mathematical sigmoid function. As can be seen, the maximum household flexibility capacity $P_{max}^{\text{household}}$ increases with the remuneration level $c_{\text{household}}$. Initially, the capacity is only slowly increasing. The households have no incentive to participate. According to consumer theory, with rising remuneration more customers are willing to substitute their power consumption with a financial benefit. The slope of the curve is increasing until a vertex occurs. The marginal utility is diminishing before that point. After the utility is saturated, an increase of remuneration does not lead to an increase of power reserve of the households. In addition, the maximum flexible capacity restricts the upper limit.

Figure 14: Maximum Household Flexibility Capacity in Dependency of the Remuneration Level

By introducing the cost sensitivity function to the optimization problem, the formulation becomes non-linear. The maximum potential flexibility of households is related to the price, which becomes the new variable in the problem. Solving this non-linear objective function requires a different approach. To keep the problem formulation linear, the household price is sampled $c_{\text{household}}$ over the range of the sigmoid function ([0,80]). The linear problem is solved for every price step in the sampling process. The optimal price $c^{*}_{\text{household}}$ is the value with the lowest outcome of the original minimization problem.
4.7.4 Supervisory Control and Communication

Modern power systems have an efficient communication network. Operators communicate with each other to coordinate actions and to exchange information. Another vital factor is the IT and control infrastructure of the grid. The power system is largely dependent on a reliable power control system, which must function under worst-case operating conditions. With the continuing deregulation of energy markets and the roll-out of smart grid devices, the requirements on the control and communication system are evolving (ABB, 2016). To use the advantages of a smart grid to their full potential, grid control and communication needs to be more reliable, more efficient, more secure, and more flexible. In this paper, three different stages of communication and control are assessed: full grid control and communication, simple decentralized control, and no control and communication. These three stages depict various technological developments of a power system. The objective is to investigate at what degree communication and control have an impact on the utilization of flexibilities in the distribution grid.

Full Smart Grid. The first stage is characterized by a high interaction between all parties in the grid operation. The power flow situation in the grid is communicated throughout the whole system. This means that aggregator, DSO, and TSO have full information of each other’s operation. Further, flexibilities are fully controllable, regarding their technical and operational thresholds, and can also be activated separately from each other. The disadvantages are the high costs of communication, IT, and control infrastructure.

The optimization problem outcome (without any further constraints) simulates this scenario. Taking grid constraints into account, every flexibility can be deployed to its full economic potential.

Decentralized Control. The second stage offers a limited control of the flexibilities. Further, information about the grid situation is only partially available. The utilization of the flexibility pool is controlled in a decentralized manner by different parties. In this case, flexibilities are not individually controllable. In the case of the deployment of flexible power, all assets are regulated proportionally until the DSO communicates the first congestion in the distribution grid. Single assets are not deployed up to their full potentials. This scenario offers a lower cost and less complex implementation compared to the first one.

The optimization model must be adjusted for this case. For every redispatch event \( t \), all \( P_{\text{flex}}^{it} \) are increased proportionally until the first flexibility violates the grid constraint. At that point, the optimal operation is reached, and the algorithm goes on to the next step.

No Communication. The last stage has no kind of information exchange between aggregator and grid operator. For the aggregator, the power flow situation in the grid is rather unknown. In order to avoid complex control infrastructure and grid monitoring, a simple flexibility control mechanism is implemented. The grid operator calculates the maximum deployment of each asset in a worst-case scenario. This lower limit is the operational set point for the asset. In the case of a demand call, each flexibility is only running at its lower limit. Flexibilities can always be deployed independently of the grid situation. Since this scenario is vaguely the state-of-the-art of the current grid development, no investment is needed. Thus, it represents the least-cost flexibility operation.

In the model, every grid scenario of the day is simulated. For every hour, the maximum power provision of the flexibility is calculated. The set point for flexibility is the hour with the lowest power provision. This eventually means that the flexibility is always operated at this level for every redispatch measure.

---

3 Data accessed: Nov 15, 2016
The different parameters for control and communication are only used in the redispatch model. Distributed flexibilities, which are procured and deployed for secondary redispatch, are usually pre-qualified and controlled within the secondary reserve control market.

5 Results

In the following we present exemplary results of the two optimization models, which are described in the previous section. In order to have a correct assessment of the different cases, all results are simulated with the identical initial data input (i.e. amount of flexible assets, level of increased PV penetration, maximum available household flexibility etc.)

5.1 Case 1: Copperplate vs. Optimal Power Flow

This section shows the result of the redispatch support optimization. The results mainly focus on two different cases. The first part shows the impact of grid constraints in comparison to the optimization with the copperplate scenario. Depending on the grid load and PV penetration, network limits can have a significant impact on the results.

Table 6 shows the final result of the redispatch support optimization problem. The maximum potential, which is described through the result of the copperplate scenario, is around 490 MWh. The OPF approach reduces the total deployed flexibility by 6%. Despite a significant increase of PV power generation and load penetration, the impact of the network limits is arguably small. An analysis of the applied grid shows that the grid in general is very well developed.

The total profit is around €17,450 for the copperplate scenario. This leads to a return of 35.61 €/MWh. It is questionable, however, whether this level of return can provide a sufficiently strong incentive to the flexibility operators.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Total Flexibility Capacity [MWh]</th>
<th>Total Profit [€]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Copperplate</td>
<td>490.57</td>
<td>17,450</td>
</tr>
<tr>
<td>Optimal Power Flow</td>
<td>460.96</td>
<td>16,419</td>
</tr>
</tbody>
</table>

Figure 15 shows in detail the total supplied flexibility energy of each asset and household. The industrial assets are connected to the regional distribution system and, thus, are usually less affected by grid constraints (most limits occur in the low voltage system). The household flexibility PQ 14 is also connected directly to the regional distribution grid. The high energy demand of PQ 14 provides ideal conditions for flexible loads. The PV power plant deployment is, compared to other assets, more cost-intensive, though. Also, it can only provide negative power control and is strongly dependent on the solar irradiation ($\lambda_{load}$). Consequently, compared to its nominal power, it contributes only little to the total flexibility amount.
Figure 15: Total Supplied Flexibility Capacity as Redispatch Support [MWh]

Figure 16 displays the total profit of each asset and household. It is directly proportional to the flexibility of power deployment.

Figure 16: Total Flexibility Profit [€]

5.2 Case 2: Cost Sensitivity Function, Control and Communication

Whereas in the first part the household flexibilities are characterized by their marginal cost, the second part uses the cost sensitivity function (cf. Section 4.7.3). In addition, the impact of the degree of communication and control is assessed.

The remuneration level is decisive for the maximum provision of the household’s consumption. Figure 17 shows the relation between an increasing price level and the flexible power supply. The optimal price $c_{\text{household}}^*$ is €37. A higher price is able to enhance more flexible energy. However, this leads to a lower profit, since the price level surpasses the cost of hydro power deployment. The power deployment curve has several inflexion points. The reason for this is the fluctuating energy spot price of the different redispatch events.
Figure 17: Redispatch Support: (a) Total Flexibility Profit [€] and (b) Energy Deployment [MWh] in Dependency of the Sensitivity Costs

Figure 17 also contains the curve for the approach with the decentralized control of household flexibility and the approach with no communication exchange. Note that the industrial assets are not affected by this parameter (see Section 4.7.4). Table 7 shows the final results of the total flexibility deployment and the return of the three different communication parameters. The full smart grid approach can be compared to the previous results of Case 1. It can be seen that the cost sensitivity function has a massively decreasing effect on the profit. The amount of flexibility decreased by 18.5% to 399 MWh, whereas the profit is reduced by approximately 42% to €10,082.

Table 7: Final Results Redispatch Optimization with the Cost Sensitivity Approach

<table>
<thead>
<tr>
<th>Scenario</th>
<th>$c_{\text{household}}$ [€/MWh]</th>
<th>Total Flexibility Capacity [MWh]</th>
<th>Total Profit [€]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full Smart Grid</td>
<td>37</td>
<td>399.24</td>
<td>10,082</td>
</tr>
<tr>
<td>Decentralized Control</td>
<td>37</td>
<td>354.37</td>
<td>8,942</td>
</tr>
<tr>
<td>No Communication</td>
<td>37</td>
<td>91.58</td>
<td>3,200</td>
</tr>
</tbody>
</table>

Compared to the full smart grid scenario, the decentralized control offers nearly the same flexibility potential. The flexibility deployment and the profit decreases by 11%. Regarding the massive costs for the infrastructure of a full smart grid environment, the decentralized control approach can provide a cost-efficient alternative for the future operation with flexibilities. The total deployment of the assets and household flexibilities in the full smart grid scenario can be seen in Figure 18. The results are similar to the results of Case 1.
In order to determine the operational limit of the flexibility, a power flow for the whole day is calculated (see Figure 19). In that power flow, the different asset and household flexibilities try to provide power support throughout the day. In the case of grid limits, or missing load ($\lambda_{load}$), or lack of solar irradiation ($\lambda_{PV}$), the flexibility has to restrict its power injection or consumption, respectively. Figure 19 simulates the continuous supply of positive power. The operational set point for the individual asset and household flexibilities is the minimum power supply of the day, leading to the dismissal of the PV power plant, and the households PQ 25, PQ 26, PQ 27, and PQ 31. As can be seen in Figure 20, the dismissed flexibilities are unable to provide any power support. The scenario of the flexibility control without communication guarantees a secure grid operation, but reduces the utilization of flexible resources to a minimum.
5.3 Secondary Reserve Results

In the second model, the utilization of flexible consumers and power generation for secondary control reserve measures is optimized. The key point here is that the provision of reserve power in the procurement process is quite lucrative. However, the actual reserve deployment can diminish the total profit (if $c_{\text{deploy}} \leq c_{\text{flex}}$). It is assumed that the optimization problem sets $c_{\text{flex}}$ as high as possible in order to enable as much flexible capacity as possible. The exact amount can be calculated in the case where the deployment ratio $r_{\text{deploy}}$ is known, or can be precisely estimated. This case is considered in the scenario ‘Optimal Case’ in Figure 21. However, in reality the actual deployment can hardly be forecasted. Therefore, two other scenarios are assessed in the optimization: the ‘Average Case’ and the ‘Worst Case’.

**Average Case:** The flexibility operator or the aggregator, in the case the flexibility is part of a pool, calculates the expected deployment ratio with the average ratio of existing historical data:

$$r_{\text{deploy}}^{\text{avg}} = \frac{\sum_{t=1}^{N} r_{t}^{\text{deploy}}}{N}.$$  \hfill (17)

If the real ratio is lower than the average one, the operator loses prospective profits. Conversely, if the operator procured less power for less money, he eventually reduces the losses of an expensive flexibility deployment.

**Worst Case:** For the worst-case scenario, the maximum historical deployment ratio is taken as the reference value:

$$r_{\text{deploy}}^{\text{max}} = \max(r_{t}^{\text{deploy}}).$$  \hfill (18)

The operator protects himself against losses. However, this might also lead to a higher loss of profit.

Table 8 shows the final results of the optimization. The alternative ratios have a negligible impact on the total procured power reserve. However, they are achieving significantly lower profits because of their lower remuneration price. Figure 21 shows the total profit in dependency of the price level $c_{\text{household}}$. Notice that the green power deployment curve is almost constant after it has reached the peak value. The reason for this is the relatively high level of procurement remuneration. Even beyond several hundred Euros, the optimization still tries to keep the full flexibility potential, as the return of 1 MW procurement remuneration is higher than paying $c_{\text{household}}$ for the deployment ratio. With an increasing price for the deployment, the curve is slowly converging.

---

Figure 20: Total Profit from the Optimal Flexibility Redispatch Support with the No Communication Approach
Figure 21: Secondary Support: (a) Total Flexibility Profit [€] and (b) Deployment [MWh] in Dependency of the Sensitivity Costs

Figure 22 shows the total profit and power distribution for the optimal price of each scenario. Similarly to previous results, the largest contribution is provided by household PQ 14 and both cooling warehouses. The average profit of providing 1 MW of secondary reserve power is around €3,500. The utilization of flexibilities for reserve control has enormous potential. With the development of IT and control infrastructure in the power system, the implementation and control management of flexible industrial consumers and households becomes more cost-effective.

Table 8: Final Results Optimization Secondary Reserve Support

<table>
<thead>
<tr>
<th>Scenario</th>
<th>$c_{Household}$ [€/MWh]</th>
<th>Total Procured Power Reserve [MW]</th>
<th>Total Profit [million €]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Optimal Case</td>
<td>57</td>
<td>492.27</td>
<td>1.97</td>
</tr>
<tr>
<td>Average Case</td>
<td>49</td>
<td>489.57</td>
<td>1.774</td>
</tr>
<tr>
<td>Worst Case</td>
<td>45</td>
<td>485.5</td>
<td>1.54</td>
</tr>
</tbody>
</table>
6 Conclusion

In this study, the utilization of flexible distributed energy generation and consumption for ancillary services is analyzed. The application of those flexibilities focuses on the power balancing support from the DSO-side to the TSO. The objective is to achieve an economic improvement in the grid operation by using the available flexibilities for redispatch measures, and in the secondary reserve market. Historical data of redispatch and secondary reserve measures are used to calculate the demand for flexible capacity. Further, the data on the cost of those redispatch and secondary reserve measures are decisive for the price of the flexible units. With the help of parameters regarding the flexibility availability, the flexibility price-design, and the different control mechanisms, different grid scenarios are simulated.

The optimization of both the redispatch support model and secondary reserve support model showed the possible potential of flexibility ancillary services in future electric grid operation. Due to the topology of the Swiss electricity system, cost-efficient, large-scale hydro power plants are sufficient to cover the redispatch demand. The economic improvements of the flexibility redispatch support process are not enough to justify the investment in IT and control infrastructure in order to enable these flexibilities. However, the results of the different control and communication parameters showed that decentralized control can enable around 90% of the economic improvements of the fully controllable grid scenario. Thus, a cost-intensive upgrade of the electric grid towards a smart grid is not required in most cases.

The utilization of flexibility for secondary reserve measures has enormous economic potential. The optimization results show a significant improvement in the grid operation. With the development towards a smart grid, and the financial incentive of the secondary reserve market for flexibilities, the utilization of flexible generation and demand can help to meet the future security requirements of the electric grid.
References


Michael Koller, Marina González Vayá, Aby Chacko, Theodor Borsche, Andreas Ulbig, and Swissgrid AG. Primary control reserves provision with battery energy storage systems in the largest European ancillary services cooperation. *CIGRE*, pages 1–12, 2016.


List of FCN Working Papers

2016


2014


2013


**2012**


2011


2010


2009


2008


