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Executive Summary

The Energy Transition is happening and renewable energy sources become integrated into the grid. While the efficiency of many products is increasing, the electrification and digitalisation are on the march too. This has significant consequence for the whole electricity industry. As one of many examples are the requirements to the grid changing. While power generation was for a long time based on a centralised approach, it is now based on a decentralised approach. The changing environment create new needs and opportunities. One is DR, which makes use of the consumption flexibility of demand side units by shifting them in time. This can have many different benefits and help to address some of the Energy Transition challenges.

This paper examines those new opportunities and business cases based on DR technology developed within the SEMIAH framework. On the way to define three new business models, we analyse current and potential future market frameworks such as USEF. This allowed us to define a simulation and optimisation model to quantify the values added from SEMIAH DR technology. The simulation value added is compared to the costs of implementing and running such a technology. We found that the margins for those business models are low but in combination of know-how an efficient DR system, it is possible to develop a new marketable product that can help to make our grids smarter and to realise the green shift.

Abbreviations

D	Deliverable
EC	European Commission
ESL	Electricity Supply Law
TSO	Transmission System Operator
PCR	Price Coupling of Region
OTC	Over the counter
BEP	Balancing Energy Price
KEV	Feed-in remuneration at costs
CHF	Swiss Frank
EUR	Euro
EEG	Renewable Energy Act
DKK	Danish Kroner
PHS	Pumped Hydro Storage
MCM	Market Coordinating Mechanism
ESCo	Energy Service Company
BRP	Balancing Responsible Party
DAM	Data Access-Point Manager
MIS	Misurio
DEV	Develco
ROM	Reserve Option Market
KPI	Key Performance Indicator
EV	Electric Vehicle
PV	Photovoltaic
CAPEX	Capital Expenditures
OPEX	Operational Expenditures
NPV	Net Present Value
ICT	Information Communication Technology
WP	Work Package
WT	Work Task
DSO	Distrbution System Operator
DoW	Description of Work
IoT	Internet of Things
NaN	Not a Number
SoC	State of Charge
MWh	Mega Watt Hour
kWh	Kilo Watt Hour
ADS	Active Demand Side
DR	Demand response

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1 Introduction

The world stands before a new chapter when it comes to energy. The transition towards renewables is ongoing and the electrification of more devices takes place. Rising demand and green energy sources put us in front of many new challenges and the requirements on the market framework changes. One huge difference is the decentralisation of electricity markets.

To still can provide a system that guarantees high stability, availability and security a smart grid can help. Making demand side devices smart allows us to unlock a large amount of flexibility. In SEMIAH the idea is to shift consumption of households on the time axis. Only considering individual households in not enough since the cost are too high in relation to the revenues getting from it. Therefore, an aggregation of many devices and households is required, so that the flexibility can be exploited at different markets for different purposes.

The targets of deliverable of WP9 is the quantitative analyse of the economic value of flexibility provided by SEMIAH technology. Business models are derived from already existing future market framework. The business models describe the principles, the stakeholder involved and outlines benefits for each of them. Part of this report (D9.2) and therefore WP9 is also the Master Thesis of Funk & Wood (2017).

D9.2 is the final product of WP9 and basically contains elements of most of the tasks of WP9. The document starts with an introduction of the opportunities for Demand Response (DR) under the current circumstances and goes then over into an analysis of the electricity markets in the four SEMIAH member countries Denmark, Germany, Norway and Switzerland. Additionally, Funk & Wood do an even more detailed Analysis of the Norwegian electricity market. The characteristics of the different markets matter for the development of business models and for the structure of the simulation that will be done to evaluate the value of flexibility. Some details will be more for informative purposes and to have complete picture and others of great importance during the whole document.

In a next step, the deliverable focuses on market frameworks and business cases. Initially it was planned to use three models from the European smart grid task force as a basis for business cases/models. Since the three models mostly describe the potential handling of grid data, we have introduced another market framework called USEF for the same purpose. All four approaches are explained in this document. After introducing some market frameworks, we have identified business case layers and potential frameworks for the development of our final business models. Before, we have described data and methodology and results of the actual simulation to evaluate the economic value of flexibility and DR. The results are analysed and interpreted. CAPEX and OPEX for the SEMIAH technology is estimated to compare to the value added of flexibility. Based on this we must derive a Net Present Value (NPV) to check how likely it would be to invest into a technology such as developed by SEMIAH.

Eventually, we gathered all our findings and developed three business models that could be implemented now and in the future. The business models describe their potential revenue streams and stakeholders involved, as well as the market framework required. The whole deliverable is closed with a comment to the current circumstances regarding policy and the conclusion.

An overview over the tasks and objectives defined in the DOW and where they are considered in this document can be found in Table 1.

Overall Objectives of WP9

Objective	Task	Section
Identify the economic value of the flexibility of household loads and the corresponding markets and business partners.	T9.1 Identification of trends and practices for energy/flexibilities trading in various countries.	Chapter 2 to 4 - this section is a summary of the internal report analysing the different SEMIAH markets
Estimation of the overall financial benefits based on today's and future market designs and the development of prices.	T9.2-T9.4	Chapter 3 to 4
Develop economically feasible business cases and derive appropriate business models.	T9.5 - Development and evaluation of business models.	Chapter 6 and 7

Sub objectives of WP9

Objective	Task	Section
Analyse the existing and future market places	Task 9.1 – Identification of trends and practices for energy/flexibilities trading in various countries.	Chapter 2 to 4 (as well as internal report D9.1)
Definition and specification of a mathematical market model for the simulator including KPIs	Task 9.2 – Specification of a mathematical market model for the quantification of financial benefits.	Chapter 5 (as well as internal report D9.1)
Adapt existing MIS tools to the models derived in T9.2 and simulate the base case	Task 9.3 – Implementation of market model and solving of a base case.	Chapter 5
Simulate the different cases and scenarios	Task 9.4 – Case studies and scenarios.	Chapter 5.5
Derive feasible business models and describe them in an economic context	Task 9.5 – Development and evaluation of business models.	Chapter 6 and 7

Table 1: The table outlines in which section an answer to which objective can be found and which tasks it concerns.

2 Big picture and opportunities of demand & response

Renewable energy sources, smart gird, electric vehicles, batteries, Internet of things… We can find all those keywords in the newspaper daily. They all have in common that they are said to be disruptive technologies and change the electricity markets as we know them today. Some of them might already have started to do so while other are just ideas yet. Thus, people have come up with many different future market frameworks for an integrated European electricity market, feeding our need for power with green technologies. Since we are just at the beginning of a new epoch regarding electricity many things are uncertain. Especially the economic side still leaves us with many questions. This is particularly true for DR. DR gives us many possibilities for new services and products. However, most players still struggle in finding profitable ways to exploit those business cases.

The basic principle of DR is based on the change of consumption pattern from a consumer through different actions and technologies according to certain signals. This can be achieved simply by giving a consumer a high price during the day and a low price during the night, e.g. the charging of his electric vehicle (EV). The consumer then may shift some of his electricity consumption to the night time or even tries to reduce it. In that simple case, the signal for the consumer is the price or tariff he must pay to the supplier. In other terms, the consumer exploits the flexibility in charging his EV. It does not have to happen during the day necessarily so he can adjust its charging behaviour and shifts consumption over time. However, without any incentive or signal sent to the consumer (lower night tariff), he would not have any motivation to change its behaviour. He would plug in his EV whenever he arrives home. Thus, the signal is essential. This is an example of manual DR, which relies on the consumer’s active participation. Many people do not want to bother about when to turn on or off certain devices. Consequently, one can automatize the DR, so that the EV automatically charges over night (or certain defined hours. Taking it even another step further, the EV could react to a changing (price) signal and charge when it is the cheapest. For automatic DR, appropriate technology is required consisting of software and hardware. The technology is offered by a third party in exchange for some reward. The third party could profit from the consumer by exploiting his flexibility, by data about his consumption pattern or by receiving money.

The EV charging example is simplified and there are many ways of providing a DR service. DR does not have to be in combination with small end consumers (households). DR could refer to any demand sided unit that has the possibility to adjust its consumption behaviour. DR can be used for industry plants, factories, office buildings and many other things. The main principle is just to smartly control the demand sided units and ideally exploit their flexibility on different markets or optimise them towards other objectives. Often it is difficult though, to have a scale large enough to exploit demand flexibility efficiently. Thus, several smaller devices are often aggregated to a larger virtual unit, that appears at the market as one large or several large consumers. That is why the third party is often referred to as an Aggregator. Especially with households, the function of an Aggregator.

The role of an Aggregator can basically be taken over by anybody. Some existing market players might be more likely to slip into that role than others.

Aggregators not just have to exploit the demand side flexibility. They can also include more complex energy systems containing generation plants and storage facilities. The combination of assets such as consumption units, generation plants and storage possibilities, allows the Aggregator to extract much more flexibility out of his portfolio. E.g. solar energy can be stored in a battery and used at a later point in time when it will be useful. The aggregated fallibility is exploited underlying different constraints or targets. The easiest example is to sell the flexibility on the market and optimise electricity purchases against market prices. This can especially be of high interests for industries and large buildings to minimize their costs. Another possibility is to sell flexibility on the ancillary service market to contribute to the grid stability. In this business case, the consumer is required to keep a certain flexibility during a defined amount of time, e.g. day, week or season. In a situation of a shortage or an excess of power the Aggregator can so provide more or less energy. Another possibility is to optimise the consumption against grid tariffs or constraints, so that costs and investments will be minimised. There are many more opportunities such as optimisation against subsidies, balancing costs or operation costs (compare Figure 1).

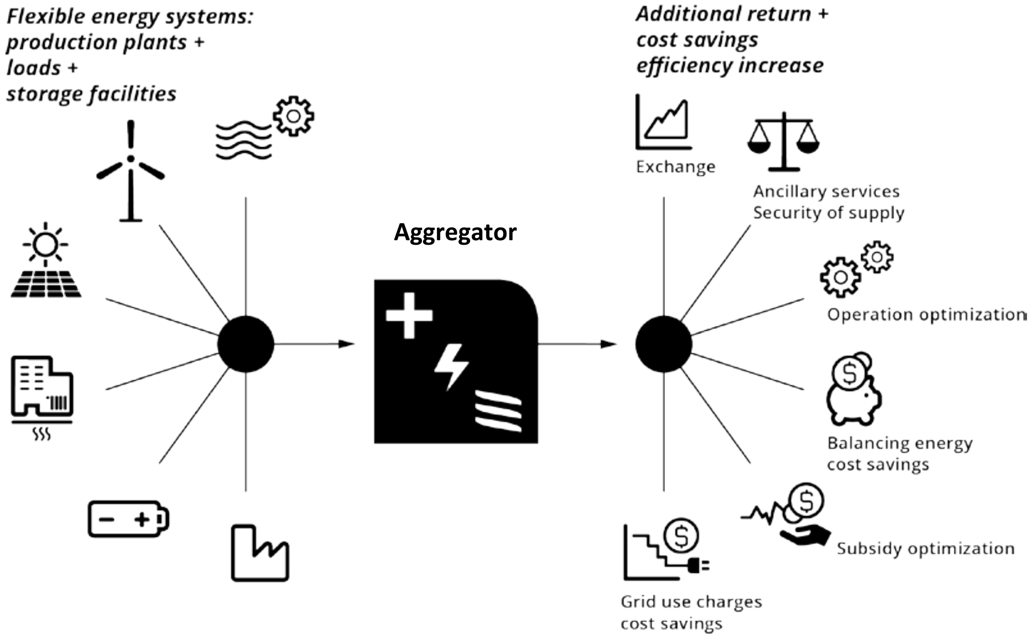


Figure 1: Flexibility Exploitation Scheme shows on the left side the ADS devices, which provide flexibility for the Aggregator and on the right-hand side shows the possibilities how to exploit the gained flexibility on the.

Automatic DR does not only have to exploit flexibility against external signals. It could be a target to make a house or building as self-sufficient as possible. The most obvious example is a house with rooftop solar and a battery. When the sun is shining, the solar energy produced either will met the immediate demand of the household or it is used to charge the battery. When the sun is not shining, consumption of the building is reduced to a minimum and the rest is feed by the battery. Only if there is more demand for power than energy produced by the solar cell or than can be supplied by the battery, electricity from the grid is purchased.

In addition to shifting energy consumption over time, DR brings other benefits such as insights into consumption behaviour and remote control of devices. While an energy supplier or a grid company can learn about his clients, the end consumer itself can profit from pre-heating his house after a vacation. There is basically no limit for new ideas and we do not see what the future will look like yet. Nevertheless, it is a rocky road ahead to bring all those ideas and technologies to the market and successful. In the following chapters, we will more deeply assess opportunities and challenges that need to be solved.

3 Market framework in Norway, Denmark Germany and Switzerland

In this chapter, we are providing an overview about the different market frameworks in Germany, Denmark, Norway and Switzerland. Even though Europe is pursuing a common united electricity market with similar or identical market frameworks, each market has still its very own regulations and set up. There has been a huge progress within the last ten years towards the common goal of one single market and the overall integrity has improved a lot. Nevertheless, the differences are still big, so that we cannot just use one single model to describe the markets.[1] For the definition and evaluation of business cases, market regulation and framework differences play an important role. In this chapter, we are going to focus on each of the SEMIAH member countries on the topics deregulation, exchange markets, ancillary services, subsidies, electricity tariffs including grid costs and balance energy. Those topics will be relevant for the market simulation later and are essential for the exploitation of flexibility.

3.1 Legal Framework

Europe is aiming for one deregulated electricity market. To reach that target the different electricity markets in all countries need to be harmonized. One of the first step was to deregulate the markets. A focus lies on the unbundling of supply and distribution, as well as the establishment of an independent Transmission operator. The disintegration of electricity markets has not been fully finished in the four participating countries. The different progresses of the unbundling and other relevant legal issues are described in this chapter.

3.1.1 Switzerland

In Switzerland, the 2008 Electricity Supply Law [ESL] consist the most important legal framework for the electricity sector. The law enabled an independent transmission system operator [TSO], which is called Swissgrid. The TSO’s main objectives are to provide non-discriminating access to the grid and security of supply. In addition to the TSO, the law also anticipates the separation of distribution from other activities. This particularly concerns the energy suppliers which have been often fully integrated before (IEA, 2012).

The ESL opens the wholesale market for end consumers in two phases. From 2008 on, all end-consumer with consumption of 100 MWh per year are free to choose their energy suppliers which concerns about half of the whole Swiss electricity market. In the second phase, all end-consumers will be granted access to the free supplier market (IEA, 2012). However, the Swiss Federal Council announced a legislative process by consultation for 2018 that will introduce the full market liberalisation (BFE, 2014).

To control the compliance of practice and law, ESL introduces another independent party, which is called ElCom. ElCom checks the implementation of the law, monitors the grid access for all players and the according conditions. ElCom also reassess all the grid and energy tariffs as well as the cross-border congestions management of the TSO. In addition to the ESL, another highly relevant law for the Swiss electricity market is the Cartel Law (CL). The CL defines that a dominant position of an enterprise may exist, if it has strength on the market compared to its competitors, if the other enterprises depend on it due to structural reasons (IEA, 2012).

Since 2007 is the Swiss Federal Council negotiating for a bilateral agreement in the electricity market. The aim of the agreement is to receive full access to the European electricity market. In 2010, the Swiss Federal Council has extended the negotiations. They are considering changes in the European legislation relevant for the electricity market. The extended agreement focuses on a comprehensive, long-term solution. Priority lies for both parties on security of supply. A contract

[1] An example for a future market framework for a standrdized European elctrictiy market is USEF.

should therefore govern the cross-border electricity trading, harmonizing security standards, grant the free market access and ensure the participation of Switzerland in different committees. Due to the tensions on the bilateral contracts between Switzerland and the EU, the negotiations are currently put on hold (BFE, 2012).

The most current development in the reformation of the Swiss electricity market is the referendum about the new energy law on 21 May, 2017. The voting is about accepting an update of the current energy legislation that has been developed by the federal council in 2016. It is called the first action package as part of the energy strategy 2050. The energy strategy enables the political and regulatory environment ensure electricity consumption in Switzerland from renewables only by 2050. The package also includes other actions for a more decentralised electricity market framework (BFE, 2017).

3.1.2 Germany

The liberalization of the electricity market in Germany happened in 1998. The Energy Industry Law is considered as the foundation of the market opening. After the introduction of the law, end-consumers could freely choose who they are purchasing their electricity from. Retail prices felt clearly but not for long. Merging energy suppliers took advantage of their market power. The liberalization could take full effect only after the Federal Network Agency was established as regulatory company in 2005. The agency's task is to guarantee access to the distribution network for every energy supply company (Strompreise, 2010).

The renewal of the Energy Industry Law in 2005, gird operators were no longer allowed to be involved into electricity production or sales activities. Grid operators needed to be a separate legal entity (legal unbundling). Moreover, the structure of the organisation had to be arranged in a way such that the decision-makers of the grid were independent (operational unbundling). In addition, grid operators had to treat economically information strictly confidentially and the disclosure of grid-related information that was potentially economic beneficial had to happen non-discriminatory (informational unbundling). Eventually, internal accounting and financial reporting needed to be kept separately from trading accounting (unbundling of accounts).
In alliance with the European Union (EU) unbundling requirements, grid operators must be unbundled from a legal, informational, operational and accounting perspective. Furthermore, TSO need to proof full owner ship unbundling or that grid operation is independent from electricity production and supply (Uwer & Zimmer, 2014).

3.1.3 Norway & Denmark

The Norwegian electricity markets counts as one of the front-runners in the market liberalisation. Since 1991, Norway has a fully deregulated electricity market and is open for all producer consumers. The end-users have, in contrast to Switzerland, the possibility to choose their energy supplier. Moreover, the Norwegian electricity legislation is harmonised with EU legislation (IEA, 2011a). Similar to Norway, Denmark liberalized its electricity market in the early 1990s but the full market opening happened in 2003 (IEA, 2011b).

3.2 Exchange markets

Exchange markets are the most important institutions when it comes to electricity trading. Compared to conventional stock exchanges they are young and still being developed. The trend is towards more continuous trading cross borders. Nevertheless, volumes traded over-the-counter should not be underestimated. In this section, we are introducing the two power exchanges relevant for the SEMIAH member countries EPEX and NordPool.

3.2.1 EPEX Spot

EPEX Spot was founded in September 2008 as a joint venture of the German and the France energy exchange. EPEX provides the electricity spot market for its member countries which are Germany, France, Switzerland and Austria. Derivatives cannot not be traded on EPEX. This must be done via the holding company EEX, NASDAQ OMX or OTC. The currency for the listed products on EPEX is Euros for all countries (EPEX Spot, 2016a).

3.2.2 Nord Pool

In 1991, the Norwegian parliament decided to deregulate the trading market for electricity. In 1993, Statnett Marked AS was established as an independent company for trading power products, two years after the Norwegian parliament decided to launch the deregulation of the power market. 20 years later, after several changes in organization and ownership, Nord Pool Spot consists of the member states Denmark, Norway, Finland, Sweden, Estonia, Lithuania, Latvia and new also the UK. Parallel to EPEX for Central Europe, Nord Pool Spot provides the electricity spot market for the Nordics. Nord Pool is divided into two parts: Elspot (Day-ahead) and Elbas (Intraday). Derivatives can only be traded on NASDAQ OMX or OTC. The products on Nord Pool are listed in Euro, Norwegian Crown, Swedish Crown and Danish Crown and English pound (Nord Pool, 2016a).

3.2.3 Day-ahead / Spot Market

The exchanges are divided into two separate platforms, day-ahead and intraday market. As the name suggests, only electricity products of the next day can be traded on the day-ahead market. The day-ahead market is the main market to trade power. The market driver is the member's planning. Buyers of power need to plan how much they need the next day and what they are willing to pay for that. The selling party on the other hand, needs to decide how much he is going to produce and at what price he is willing to do so. Both parties have time to submit their bids until 12:00 CET. The results of the price calculations become usually published at 12:40 or later (Nord Pool, 2016b) & (EPEX Spot, 2016b).

The aim of the day-ahead market is to create and equilibrium between supply and demand. These tasks enjoys even more attention in the electricity industry since we cannot store electricity easily (yet). The normally imagined *Invisible Hand* is in that case the power exchange. The price calculation mechanism in place is based on a double auction. Both sides, sellers and buyers, submit either an ask or a bid-price for the volume they intend to sell or buy until a set point of time each day. After the auction is closed, the auctioneer (the exchange) starts to aggregate all bids of the whole exchange area to define supply and demand curves. Simplified it can be said that the intersection of these two curves maximizes welfare and thus, defines turnover and price of power for each hour of the day. The price found is called system price[2]. In fact, the process is more complicated as through the possibility of submitting block orders (one bid for multiple hours) there is not a single solution which maximizes welfare. So, there is an algorithm that tries to find the best possible solution within a certain timeframe by using a brunch-and-cut method.

[2] The system price at EPEX is called ELIX.

Figure 2: The intersection of the aggregated demand and supply curve determines system price and turnover (Nord Pool, 2016b).

The same mechanism is also applied to each bidding area[3] separately within the whole exchange. The price resulting is called area price. If there is enough cross-border-capacity between all bidding areas available, the area prices equal the system price. If the capacities are exhausted, there will be a separate area price for each bidding area.
After the prices were calculated and published online it comes to the settlement. All sellers who have submitted an ask price lower than the price determined by the auctioneer must sell their power and all buyers who submitted a bid price higher than the according price must buy the power they wanted (Nord Pool, 2016b).

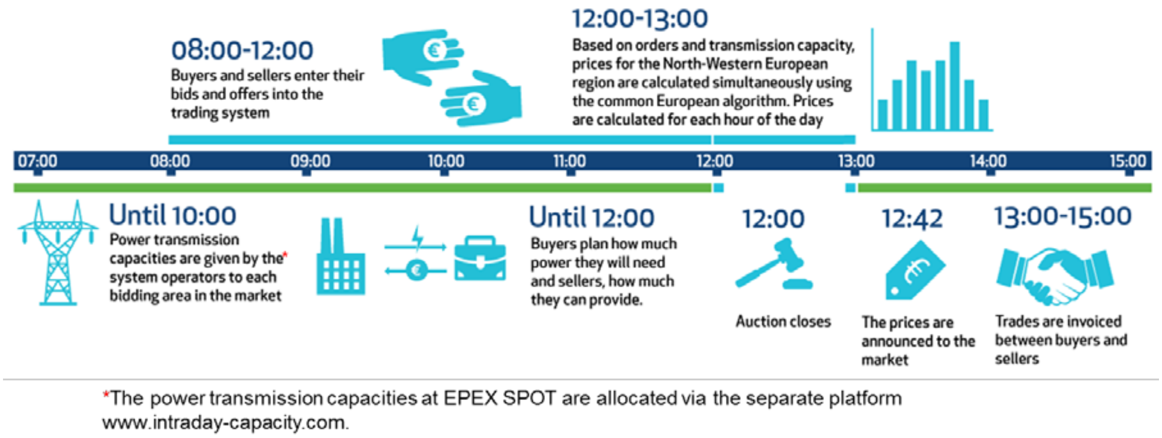


Figure 3: The process of the day-ahead market on Nord Pool Spot (Nord Pool, 2016b).

3.2.4 Intraday

Generally, the intraday market works like a normal stock exchange and provides a platform for continuous trading of power, 24-hours each day. The idea is to provide buyers and sellers a possibility to react to short-term events that was not included in their planning. The exchange facilitates potential buyers to find a seller with an identical price perception for his offer and vice versa. Each time an ask price meets a bid price it comes to a settlement. On the intraday market, power products of the same and the next day can be traded. Thus, its name does not tell the whole truth. The importance of the intraday market is increasing through the integration of more renewables and hence, the rising volatility (Nord Pool, 2016b).

Concerning bottlenecks, the same principle as for the day-ahead market is valid; if there is enough cross-border-capacity, power can be traded between two neighbour countries. The traders do not know that they are dealing with partners from other countries. All they can see is price and volume of a pending offer. The only instance with a complete overview of what is happening is the exchange itself (EPEX Spot, 2016b).

3.2.5 Market coupling

As stated above, the EU target is to integrate European electricity markets so that trades can easily been done cross borders if it makes sense. To be able to do so the markets need to be linked to each other, minimizing manual interference. The integration of markets is called market coupling. The coupling is explained in the following sections.

[3] A bidding area is defined as a region within it is possible to trade power without any restrictions and bottlenecks do not appear. This definition only refers to the financial settlement of power traded. Obviously there do not exist any bottlenecks for the physical power flow like the ones describe above.

3.2.5.1 Idea

A region that contains no grid bottlenecks for purchasing and supplying power is called bidding area. Thus, power can be traded within the area without any restrictions. Consequently, the price of power will be the same all over the area. Further such a bidding area will usually have either a power generation surplus or deficit. Apparently, it would be beneficial if two bidding areas, one with a deficit and one with a surplus, would be able to trade with each other. This would in the best-case lead to equalized trade balances and identical prices in the corresponding areas. To enable such a mechanism an optimal and automatic allocation of boarder capacities is needed. The process of allocation must be coordinated by a third party, an auctioneer. In real terms the power exchanges (e.g. Nord Pool) take over that part. The auction type is called implicit auction as the bidders do not submit their offers directly to foreign suppliers. This is done by the exchanges, which matches offers from different countries, if it makes sense economically and there is enough cross-border capacity available. In addition to the same allocation process, the exchanges also must ensure that they calculate the prices by identical algorithms to avoid conflicting mathematical approaches (EPEX Spot, 2016c).

The project to interlock the different countries for cross-border power trading is called Market Coupling. Most European countries are part of the project and already have their markets coupled. Also, Switzerland has joined the project yet due to the political tensions between Switzerland and the EU. Technically Switzerland is ready but when the final coupling will take place is not sure. It still can take a while until Switzerland will have an automatic cross-border capacity management. An important requirement for the EU is that the Swiss electricity market is fully liberalized. From Chapter 3.1.1, we know that this will not happen before 2018. Germany, Denmark and Norway already have adapted such a mechanism. Germany also has coupled its market to the Nordic one and vice versa (Swissgrid, 2016) & (BFE, 2014).

3.2.5.2 Price coupling of regions

The Price Coupling of Regions (PCR) is the initiative of seven European Power Exchanges to harmonize the calculation of power prices. This is an essential condition for the successful implementation of the market coupling. The PCR had the intention to implement the same price mechanism at each participating power exchange. The project is open for every European power exchange which wishes to join. The PCR algorithm maximizes the overall welfare considering an optimal use of cross-border capacities. In other words, it maximizes the trade volume while minimizing the price differences by applying a branch-and-cut-method. Consequently, the most competitive price based on the offers which can be calculated within a certain time limit will arise (PCR, 2015).

3.2.6 Exchange products for Switzerland and Germany

3.2.6.1 Derivatives

The market of power products can be divided into two sections: the spot market and the derivative market. EPEX only provides the spot market and does not deal with any derivatives. For trading with those products one must use EEX. There are no standardized derivatives with a Swiss index as an underlying. This means that all Swiss derivative traders must find their counterpart OTC. However, it is possible to register the OTC agreed derivatives at EEX, which facilitates the final settlement and clearing of the deal. Germany can refer to standardized derivatives on EEX as well as on NASDAQ OMX while it is still possible to register OTC trades. The two types of derivatives, options and futures, are mostly based on day-ahead indices, e.g. PHELIX for Germany and Austria. The minimum delivery rate for derivatives is between 1 and 12 MW depending on each product. The maturities available on EEX are: day, weekend, current week, next four weeks, current month, next 9 months and next 6 years (EEX, 2016).

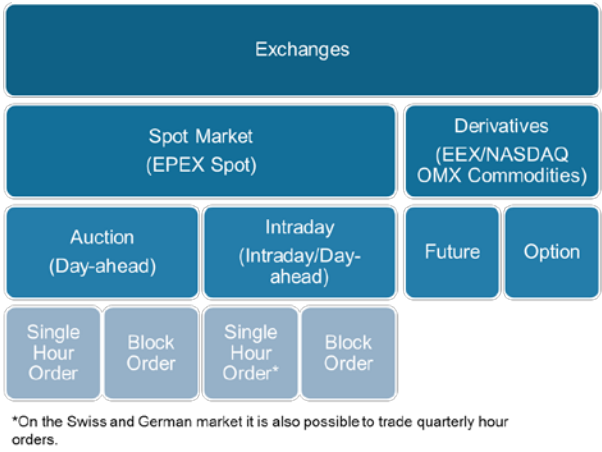


Figure 4: The products of Germany and Switzerland traded on a power exchange.

3.2.6.2 Day-ahead products

The products of day-ahead and intraday market are principally identical with the main difference that only hours of the same day can be traded on the day-ahead market.[4] They are basically divided into hourly orders and block orders. Hourly orders exist for each single hour of the day. It is possible to submit multiple price quantity combinations for the same hour. The minimum contract size is 0.1 MWh.

Block orders are used to link several hours on an all-or-none basis, which means that either the bid is matched on all the hours or it is entirely rejected. Block orders have a lower priority compared with single hourly orders. The quantity may be different for every hour of the block. A block order is chosen to be executed by comparing its price with the volume-weighted average of the hourly market clearing prices related to the hours contained in the block. The exchanges provide standardized block orders like base or peak load. Trading members do not need to use them and can also create user-defined blocks, combining several hours of their choice. There are two special types of block orders: linked block orders and exclusive block orders. A linked block order consists of maximum of 3 generations and each generation is only accepted only if the superior generation has been so. Thus, linked orders allow to submit conditional orders while exclusive orders are a combination of block orders of which only one can be executed (EPEX Spot, 2016d).

3.2.6.3 Intraday products

On the intraday market, electricity for a delivery at the same or the next day is traded in 24-hour intervals. In addition to the hourly orders, it is possible to trade quarter hours on the intraday market in Germany and half-hours in Switzerland. All three products, quarterly, half-hourly and hourly orders, do not much differentiate from the day-ahead market regarding their specifications. Except the possibility of continuous trading until 30 minutes before the hour of delivery[5] and the order types the two concept are quite similar. The same is true for block orders. Unless continuity and various order types, there are no major differences. The order types for the intraday market are the following (EPEX Spot, 2016d):

Limit Orders

Limit Orders are buy and sell orders which carry a price limit and which can only be executed at this price or at a better price (maximum bid price or minimum ask price).

Market Sweep Orders

[4] The auction only takes place once a day in contrast to the intraday market where trading is continuous.

[5] Gate closure times are continuously shortened. In Q2 2017, EPEX allows intraday products for the German market to be traded until 5 minutes before delivery (EPEX, 2017).

Market Sweep Orders are user-defined block orders with the execution restriction «IOC» (Immediate or Cancel), and are executed immediately and as far as possible against respective Single-contract Orders.

Iceberg
«Iceberg» or Hidden-Quantity Orders are large volume orders, divided into several smaller orders which are entered in the order book sequentially. The total and the initial quantity must be specified by the exchange member.

Immediate-or-cancel
The order is either immediately executed or automatically cancelled.

Fill-or-kill
The order is either immediately and entirely executed or cancelled in its entirety.

Linked Fill-or-kill
At least two up to 100 Fill-or-kill orders have together a linked execution constraint. They are either together executed or all cancelled.

All-or-none
The order is executed completely or not at all.

Good for session
The Order is deleted on the trading end date and time of the contract unless it is matched, deleted or deactivated beforehand.

Good till date
The Order is deleted on the date and time specified by the exchange member when submitting the order, unless it is matched, deleted or deactivated beforehand.

3.2.7 Exchange products for Denmark and Norway

3.2.7.1 Derivatives

The derivatives of the Nordic power market are traded on the NASDQAQ OMX. It basic types of products are also futures and options. While the delivery rate of the German derivatives vacillates from 1 to 12 MW, the Nordic ones do all have a rate of 1 MW. The maturities available on NASDAQ OMX are: day, week, quarter, month and year.

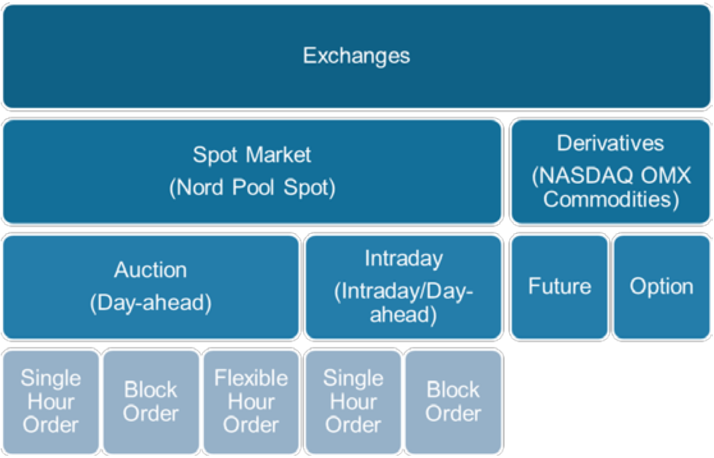


Figure 5: The products of Denmark and Norway traded on a power exchange.

3.2.7.2 Day-ahead products

The products available on the day-ahead market of Nord Pool consist of hourly orders, block orders and flexible hourly orders. Hourly orders and block orders work the same way as on EPEX but the ordering type linked block order does not exist. Instead Nord pool has flexible hourly order. For its submission traders submit a price and a volume but no specific hour. The offer will be accepted for the hour it maximizes the socioeconomic welfare (Nord Pool, 2015c) (Nord Pool, 2015a).

3.2.7.3 Intraday products

On the Intraday market of Nord Pool (ELBAS) electricity for a delivery at the same or the next day is traded continuously in a 24-hour interval. The products for trading are single hour orders and block orders[6]. Their specifications are basically identical to them at EPEX. The possible order types on ELBAS are defined as follows (Nord Pool, 2015d):

<u>Fill</u>
Matching may be effected either for the full volume or for a part of the volume. Any remaining volume shall remain valid with the ranking of the original Order.

<u>All-or-Nothing</u>
The order is executed completely or not at all.

<u>Fill-or-Kill</u>
The order is either immediately and entirely executed or cancelled in its entirety.

<u>Immediate-or-Cancel</u>
The order is either immediately executed or automatically cancelled.

<u>Iceberg Order</u>
«Iceberg» or Hidden-quantity Orders are large volume orders, divided into several smaller orders which are entered in the order book sequentially. The total and the initial quantity must be specified by the exchange member.

3.2.8 Liquidity

3.2.8.1 EPEX Spot

Even though EPEX is still a quite young exchange, it provides a liquid platform for trading power. In 2013, a total of 265.5 TWh of Germany's and Austria's electricity were traded on EPEX. This corresponds to a share of 40% of the whole power consumption in the two countries. Thereof 245.8 TWh were processed via the day-ahead market and 19.7 TWh via the intraday market. In Switzerland, the amount of electricity processed via EPEX was 19.2 TWh, which accounts for 30% of its electricity consumption. Only 0.7 TWh were traded on the intraday market. It must be mentioned that the intraday marked for Switzerland has been launched only in June 2013. In 2014, already 351 TWh were traded on the day-ahead market all three countries combined. In addition to that another 31 TWh were traded on the intraday market. This shows a steady increase in the volume traded at EPEX SPOT. Especially in the intraday market EPEX SPOT sees further potential (EPEX Spot, 2015).

[6] Strictly speaking block orders on ELBAS are not a separate product. It is only a certain order type of single hour orders. For the reasons of understandability, we are treating them like a separate product in this document.

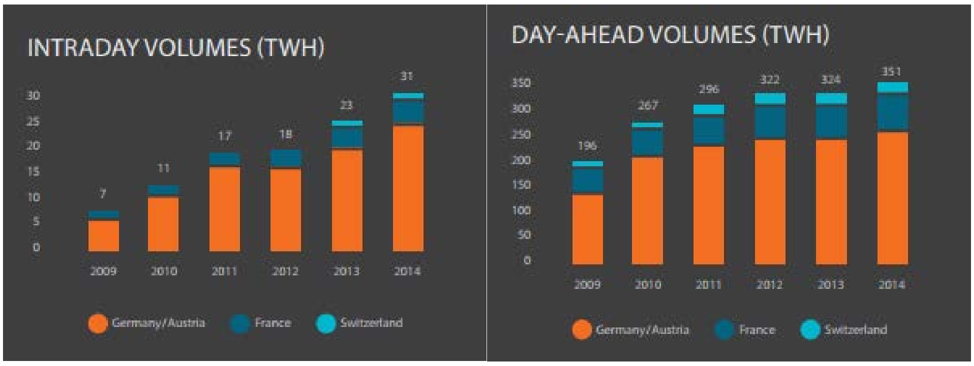


Figure 6: The volume of power traded on EPEX Spot is still increasing (EPEX Spot, 2015).

The numbers for 2015 will probably already be higher again as the overall growth of the trade volume from 2013 to 2014 was quite strong in Germany and Switzerland. Closing it can be said that the day-ahead market on EPEX SPOT plays a more important role each year and has become a non-negligible marketplace for power trading in Central Europe. Also, the intraday market gains in importance and is reflected in the movement from the ancillary service market towards a more continuous intraday market.

3.2.8.2 Nord Pool Spot

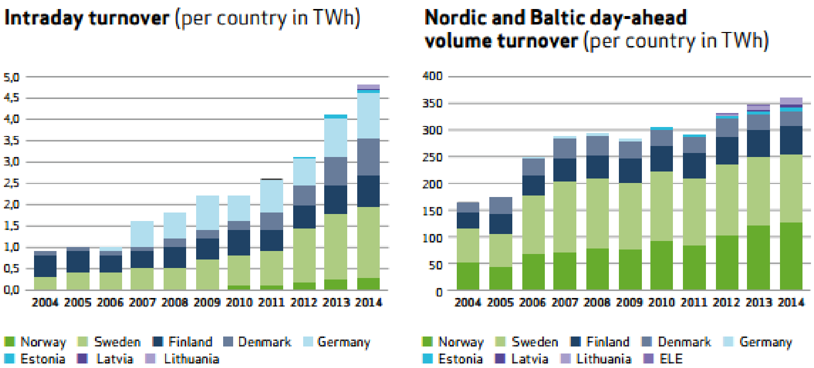


Figure 7: The development of the intraday market at NordPool over recent years is shown above. Especially the Nordic intraday market experienced significant growth within the last years (Nord Pool, 2015c).

The volume traded on Nord Pool spot is. 365.9 TWh of the Nordic's electricity are proceeded via the exchange. In addition, come 135.5 at the UK NEX. This accounts for about 84% of the total power consumption in the whole area. Most of the Nordic power, 349 TWh, is sold on the day-ahead market. These numbers underline that Nord Pool is the biggest trading platform in Europe. Without the integration of UK N2EX Nord Pool would have been over taken by EPEX SPOT (Nord Pool, 2015c).

3.2.9 Fees

The exchanges charge several annual and one-off fees for being able to participate and use their trading platform. All the fees which must be paid to EPEX Spot and Nord Pool Spot can be found under the following links:
https://www.epexspot.com/document/34180/ and http://www.nordpoolspot.com/TAS/Fees/

3.3 Ancillary services

Ancillary services are a consequence of the typical two characteristics of electricity: it cannot be stored and consumption needs to meet generation at any time otherwise there will be a power outage. Thus, ancillary services provide either more or less electricity depending on total power balance in the transmission grid. In other words, if there is too much electricity in the grid, we need negative control power. If there is not enough electricity in the grid we need positive control power. Negative control power can either be provided by decrease in generation or an increase in consumption. For positive control power, a higher generation or a lower consumption is required. Participants on the ancillary service market can usually bid to provide capacity for different periods (hours/days/weeks/seasons). The estimation of the capacities required, the bidding and the activation of the capacities is usually managed by the TSO. To participate at the ancillary service market usually a technical prequalification is needed to proof that the service can delivered.

The basic concept of ancillary services in the four countries considered is the same. The services are divided into primary, secondary and tertiary control reserves. Sometimes they are named differently but the fundamentals stay. For example, tertiary control reserves in Germany are called minute reserves. Whatever they called and however they are conceived, their first goal is to sustain the grid frequency of 50 Hz. Power plants which are providing primary control usually adjust their power production automatically and immediately after an incident (usually within 30 seconds) using local frequency measurement. Local frequency measurement means that the plant continuously matches its production according to the current grid frequency. Secondary control reserves instead set in a few minutes after any event that caused some fluctuation in the power grid. The signal to activate the reserves comes from a centralized controller which is usually the TSO. The tertiary control reserves serve as the last instance of power rebalancing. They typically set in 15 minutes after an incident and are controlled manually. For activation, the TSO contacts the affected plant via email or a phone call.

In addition to this framework there are some special ancillary services in each country. Within this report only ancillary services open for a free market are regarded. There may also be some services in each country the power plants are obligated to provide anyway with or without any reimbursement.

Tertiary control reserves are usually the ancillary services attractive for DR since the reaction time is relatively slow and hence the technical requirement not a strict as for secondary or primary. Especially for the aggregation of small demand side units this can be of great importance. An issue can however still be the minimum lot sizes. E.g. in Norway the minimum bid size for tertiary control reserves is 10 MW and in Switzerland it is 5 MW.

Due to changing characteristics of the electricity markets and the better integration of renewables, many concepts for the power balancing are currently discussed all over Europe. So far, the principles discussed are in place in all countries, even if in a slightly adjusted way. A new possibility to balance power markets is introduced in Chapter 4.1 with USEF. The following tables show the most important characteristics of the power balancing in the four SEMIAH member countries.

1. Switzerland

	FCR	FFR	ROM	REM	Grid losses	Voltage Support
TSO's terminology	Primary Control Reserve (PCR)	Secondary Control Reserve (SCR)	Reserve Option Market (ROM)	Reserve Energy Market (REM)	Grid losses	Voltage Control
Product	Symmetrical power bands	Symmetrical power bands	Asymmetrical power bands	Asymmetrical power bands	Monthly bands	Bilateral agreements
Tender Periods	Weekly	Weekly	Weekly, daily, 4 hour blocks	Daily	Monthly	-
Lot Sizes	Minimum ± 1 MW	Minimum ± 5 MW	Minimum + 5 MW or - 5 MW	Minimum + 5 MW or - 5 MW	Exactly 5 MW Bands	-
Remuneration	Pay-as-bid only service price	Pay-as-bid service price and working price	Pay-as-bid service price	Pay-as-bid working price	Pay-as-bid for each band	Tariff for delivered reactive energy
Reaction Time	30 seconds	5 minutes	-	15 minutes	According to schedule	-
Activation	Decentralized (Frequency control)	Signal from grid controller	-	Manually	According to schedule	-
Pooling	Allowed	Allowed	Allowed	Allowed	Allowed	Allowed
Volume	± 71 MW	± 400 MW	Ca. + 450 MW, Ca. -390 MW	Ca. +450 MW, Ca. -390 MW	According to power loss forecast	-

Table 2: Ancillary Services in Switzerland (Swissgrid, 2015)

2. Germany

	FCR	FRR	mFRR	Interruptible loads	Interruptible loads	Grid losses
TSO's terminology	Primary Control Reserve (PCR)	Secondary Control Reserve (SCR)	Minute Reserve (MR)	Immediately interruptible loads	Quickly interruptible loads	
Product	Symmetrical power bands	Asymmetrical power bands	Asymmetrical power bands	Immediately interruptible loads	Quickly interruptible loads	Power delivery
Tender	Weekly	Weekly	Daily	Monthly	Monthly	No specific
Lot Sizes	Minimum ± 1 MW	Minimum + 5 MW or - 5	Minimum + 5 MW or - 5	Between 50 and 200 MW	Between 50 and 200 MW	According to tender
Remuneration	Pay-as-bid only service price	Pay-as-bid service price and working price	Pay-as-bid service price and working price	Service Price (2500 €/MWh) and working price (min 100 €/MWh max 400 €/MWh)	Service Price (2500 €/MWh) and working price (min 100 €/MWh max 400 €/MWh)	Working price
Reaction Time	30 seconds	5 minutes	7.5 until 15 minutes	1 second	15 minutes	According to schedule
Activation	Decentralized (Frequency	Signal from grid controller	Manually	Decentralized (Frequency	Signal from grid controller	According to schedule
Pooling	Within the same control area allowed	Within the same control area allowed	Within the same control area allowed	Within the same control area to fulfill minimum size allowed	Within the same control area to fulfill minimum size allowed	N/A
Volume	± 600 MW	± 2500 MW	± 1600 MW	465 MW per call for bids	1000 MW per call for bids	2.04 TWh (in 2013)

Table 3: Ancillary Services in Germany (Ampirion, 2016) & (Dena, 2014).

3. Denmark

	PCR	Frequency-controlled normal operations reserve	Frequency-controlled disturbance reserve	SCR	Manual Reserve
Product	Asymmetrical control power bands	Symmetrical control power bands	Positive control power bands	Symmetrical control power bands	Asymmetrical control power bands
Tender Periods	Daily	Daily	Daily	Monthly	Daily
Lot Sizes	Minimum ± 0.3 MW	Minimum ± 0.3 MW	Minimum ± 0.3 MW	None	Minimum 10 MW, maximum 50 MW
Remuneration	Pay-as-bid only service price	Service price pay-as-bid, working price according the regulating power price	Pay-as-bid only service price	Service price individually agreed with Energinet.dk, working price according an adjusted regulating power price	Service price pay-as-bid, working price according the regulating power price
Reaction Time	First half within 15 sec, second half within 30 sec	50% within 5 sec, 50% within 30 sec	150 seconds	15 minutes	15 minutes
Activation	Decentralized (Frequency control)	Decentralized (Frequency control)	Decentralized (Frequency control)	Signal from grid controller	Manually
Pooling	Is allowed	Is allowed	Is allowed	Is allowed (different regulation for production or consumption units)	Is allowed
Volume	±27 MW	±23 MW (in 2012)	150 - 180 MW (in 2012)	±90 MW (Value may vary widely)	N/A

Table 4: Ancillary services in Denmark (Energinet.dk, 2012)

4. Norway

	Frequency-controlled normal operations reserve	Frequency-controlled disturbance reserve	SCR	Regulating power Market High quality	Regulating power Market Low quality
Product	Symmetrical control power bands	Positive control power bands	Asymmetrical control power bands	Asymmetrical control power bands	Asymmetrical control power bands Duration minimum 1 maximum 5 hours or 1 to 8 rest hours
Tender Periods	Weekly Daily	Weekly Daily	Weekly	Weekly Seasonal	Weekly, seasonal
Lot Sizes	+/- 0.1 HZ	+/- 0.1 HZ	Min 5MW Max 35 MW	Min 10 MW (Not ordinary bids min 1 MW)	Min 10 MW (Not ordinary bids min 1 MW)
Remuneration	Marginal costs as service price of the power needed to increase/reduce the frequency	Marginal costs as service price of the power needed to increase/reduce the frequency	Marginal price as service price Nordic upward/downward regulating price as working price	Marginal costs as service price and regulation price as working price	If quality does not matter, the same price as high quality If quality does matter adjusted price for low quality (lower)
Reaction Time	Immediately	Immediately	120-210 seconds	15 minutes	15 minutes
Pooling	Norwegian Market	Norwegian Market	Is allowed	Is allowed	Is allowed
Activation	Decentralized (Frequency control)	Decentralized (Frequency control)	Decentralized (Frequency control)	Signal from grid controller	Manually
Volume	± 210 MW	+ 350 MW	N/A	1700 MW (Total regulating power high and low quality)	1700 MW (Total regulating power high and low quality)

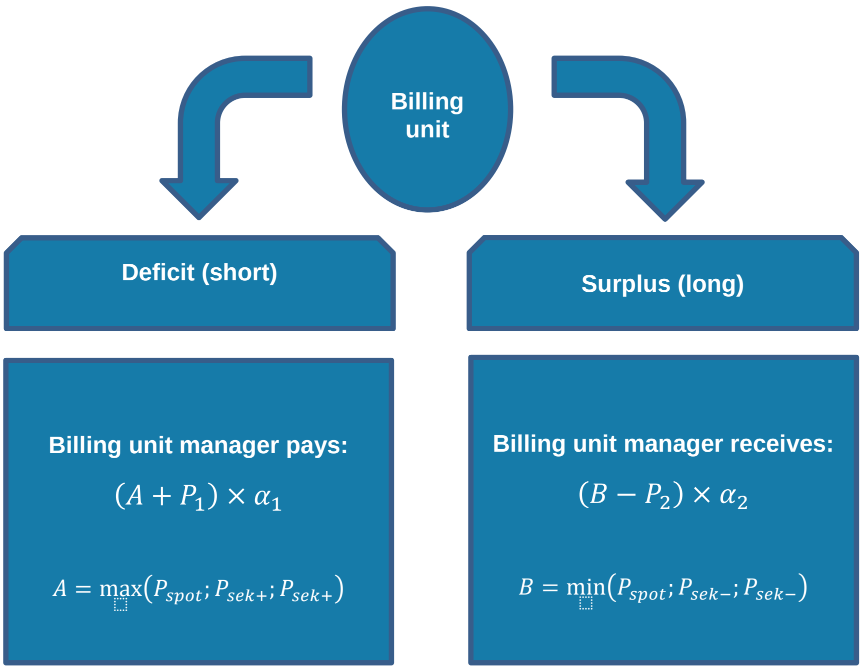
Table 5: Ancillary Services in Norway (Statnett, 2016a).

3.4 Balance energy pricing

In all SEMIAH member countries, entities which want to trade on power exchanges or provide ancillary service must be registered as Balance Groups. Each of those groups has assigned a so-called Balance Responsible Party [BRP]. The BRP is responsible for the power balancing. The sum of consumption and production of each group must sum up to zero. For a group that is consuming only, this means that its demand must be fully covered by purchases of electricity. To verify this, each group must submit a schedule with a power balance of zero before delivery time. After the delivery has taken place, a responsible authority calculates the difference between e.g. purchased and consumed power. A sum of zero as initially scheduled is unlikely due to the impossibility to precisely predict demand or generation. The positive or negative difference is penalized, so that BRP is motivated to minimize the discrepancy between scheduled load purchased load. The pricing mechanism are different in each country and are explained in this section.

3.4.1 Switzerland

In Switzerland, each consumption or production facility belongs to a billing unit. Each billing unit is responsible for their power balance at every point in time. That means total production must equal total consumption. If that is not the case, the billing unit needs to purchase balancing energy. Balancing energy can be positive or negative, depending on whether the billing unit is either short or long. If the billing unit is short the unit manager must buy additional energy. The price for balancing energy then equals a defined constant α_1 times the sum of A and a price surcharge, while A is the highest of the three following prices: the spot price, the price for called positive secondary energy and the price for called positive tertiary energy. If the billing unit has an energy surplus the billing unit manger receives money for the excess energy. The balancing energy price then equals the constant α_2 times the difference of B and a price deduction, while B is the lowest of the following three prices: the spot price, the price for called negative secondary energy and the price for called negative tertiary energy. If the sum of A and the price surcharge is negative, constant $\alpha_1$is replaced by α_2. If the difference of B and the price deduction is positive, $\alpha_1$and α_2 are swapped as well. According to this pricing model the billing unit is always worse off if they must purchase balancing energy compared to the free market (Swissgrid, 2012).



Factor α as following	α_1	1.1
	α_2	0.9
Factor P as following	P_1	1 Rp/kWh
	P_2	0.5 Rp/kWh

Figure 8: The balancing energy price scheme for Switzerland.

3.4.2 Germany

The principle of billing units in Germany is the same as in Switzerland. Each consumption or production plant belongs to one billing unit. All groups are responsible to keep the balance of their own power consumption and production. If there is an excess or a lack of electricity, the billing unit needs to sell or buy additional energy. The balance energy price is symmetrical and calculated for each quarter hour. It is derived by following the four steps (TransnetBW, 2016):

Step 1: General Balancing Energy Price Calculation

In the first step the general balancing energy price is calculated (*BEP*). For this purpose, the total amount of expenses for power balancing in Germany (total costs (*C*) minus total revenues (*R*)) is divided by the absolute amount of balancing energy purchased (*E*). The absolute amount of balancing energy equals positive balancing energy minus negative balancing energy.

$$BEP_1 = \frac{(C - R)}{E}$$

Since the BEP can also become negative and billing units are purchasing either positive or negative balancing energy, the cash flows can result as follows:

- Positive *BEP* and positive balancing energy purchased: Billing unit manager pays TSO
- Positive *BEP* and negative balancing energy purchased: TSO pays billing unit manager
- Negative *BEP* and positive balancing energy purchased: Billing unit manager pays TSO
- Negative *BEP* and negative balancing energy purchased: TSO pays billing unit manager

Step 2: Limitation of BEP

If *E* is relatively small compared to the total expenditures a high value for *BEP* can result. Therefore, it is necessary to set a maximum price to avoid extreme cash flows into one direction. The maximum value BEP can reach is defined as the absolute value of highest activated price of secondary or tertiary control reserve within the last quarter hour (AP_{max}).

If $BEP_1 \geq 0$, $\quad BEP_2 = \min(|BEP_1|\,;\,|AP_{max}|)$

If $BEP_1 < 0$, $\quad BEP_2 = (-1) \times \min(|BEP_1|\,;\,|AP_{max}|)$

Step 3: Exchange Linking

To minimize the possibility to arbitrage by optimizing balancing energy consumption against the exchange prices, the *BEP* needs to be linked to the intraday prices. To do so the *BEP* is compared with the mean, volume-weighted intraday spot-price at EPEX Spot (*ID EPEX*). If the billing unit has purchased negative balancing energy, the minimum of *ID EPEX* and BEP_2 is considered for the fourth step. If the billing unit has purchased positive balancing energy, the maximum of *ID EPEX* and BEP_2 is chosen. Thus, *ID EPEX* represents kind of either a lower or a higher price limit.

If the billing unit purchases negative balancing energy $BEP_3 = \min(ID\ EPEX\ ; BEP_2)$

If the billing unit purchases positive balancing energy $BEP_3 = \max(ID\ EPEX\ ; BEP_2)$

Step 4: Surcharges/deductions

Billing units, which significantly contribute to reduce balancing energy, have the opportunity to receive an additional surcharge or deduction on the *BEP*. This should serve as an incentive to keep the efforts on balancing the power grid low. If the billing unit has a negative power balance (PB_{Unit}) in the amount of at least 80% of the total activated control reserve which is positive(CR_{pos}), the billing unit manger gets a surcharge of 50% of the current BEP but maximum 100 €/MWh and vice versa.

If $PB_{Unit} > 0.8 \times CR_{pos}$

$$BEP_4 = BEP_3 + \max(100\,€/\mathrm{MWh}\,; 0.5 \times |BEP_3|)$$

If $PB_{Unit} < -0.8 \times CR_{neg}$

$$BEP_4 = BEP_3 - \max(100\,€/\mathrm{MWh}\,; 0.5 \times |BEP_3|)$$

If $-0.8 \times CR_{neg} < PB_{Unit} < 0.8 \times CR_{pos}$

$$BEP_4 = BEP_3$$

3.4.3 Nordic (Norway, Sweden and Finland)

The basic concept of billing units and balance energy in the Nordics is the same as in Germany and Switzerland. But the Nordic countries distinguish between production plants and consumption plants. The whole Imbalance system is regulated at one legal instance eSett. This increases the liquidity and lowers costs. To calculate the balancing energy price, they either use a 1-Price-Model for consumption plants or a 2-Price-Model for production plants. The reason for that is simple: production plants must pay or receive the regulation price for electricity if they work against the grid balance. Since the regulation price for upward regulation is higher than the spot price in times of power scarcity and the regulation price for down-regulation is lower than the spot price in time of power excess, they are in both cases worse off purchasing instead of avoiding any balance energy. If Production plants work in alignment with the actual grid balance, they pay or receive the spot price. Consequently, they are whether penalized nor rewarded.

Consumption plants have the chance to not be punished if they support the grid balance. If not, they pay or receive the regulation price for power. Therefore, they can achieve the same price on the regulating market than on the spot market if they consumed less than scheduled in times of general power scarcity and the other way around.

The way to compute the balancing energy of a billing unit is different than the one for Switzerland and Germany. The production imbalance is simply the difference between registered effective production and scheduled production. The power imbalance of consumption plants is the sum of scheduled production, effective registered consumption and the scheduled trades (eSett, 2015).

	Up-regulation hours	Down-regulation hours	Hours with no direction
Two-price model for production imbalances			
Negative production imbalance of BRP	Up-regulation price	Elspot	Elspot
Positive production imbalance of BRP	Elspot	Down-regulation price	Elspot
One-price model for consumption imbalances			
Negative consumption imbalance of BRP	Up-regulation price	Down-regulation price	Elspot
Positive consumption imbalance of BRP	Up-regulation price	Down-regulation price	Elspot

Table 6: Pricing system for consumption and production balancing energy (eSett, 2015)

Even though Denmark is not part of the joint Nordic system, the balancing energy pricing system works the same way.

3.5 Subsidies

Renewable electricity sources receive subsidies in most European countries. Even though most countries intend to slowly phase out subsidies within the next years or decades, they still play an important role in the enablement of green electricity generation. The models vary a lot among countries and technologies. This section gives an overview on subsidies by country and the most relevant technologies.

3.5.1 Switzerland

3.5.1.1 KEV (Feed-in remuneration at costs)

KEV is a subsidy-system in Switzerland that guarantees the producers of certain renewable energies to sell their power to a set minimum price that covers their production costs. The price the producers in the end receive consist of two elements: the current market price to which they sell their electricity and the difference between the minimum price and the current market price (KEV surcharge).

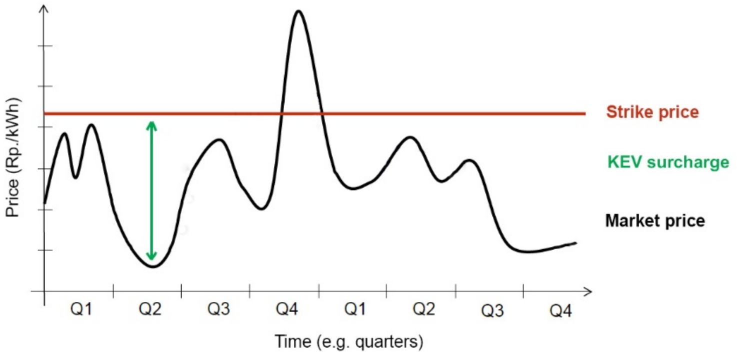


Figure 9: The KEV surcharge is the difference between strike price and market price (BFE, 2015).

Thus, if the market price stays below the defined minimum price each producer will always receive the minimum price. Whether a producer will fall into the KEV system, the one-off investment grant system or none of them depends on the performance of the plant (see Figure 10: The subsidy system of renewable energy slightly changed in 2013 . The granting period is between 20 and 25 years depending on the type of technology (BFE, 2015).

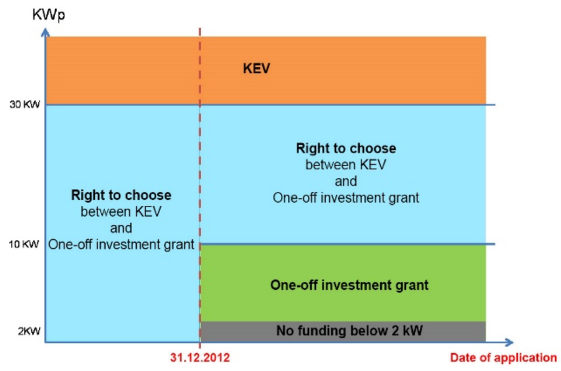


Figure 10: The current subsidy system of renewable energy in Switzerland slightly changed in 2013 (BFE, 2015)

Even though this model guarantees investment security, it is far away from any market reality and leads to inefficiency. Therefore, the Federal Council announced a new system which should be closer to the market and still guarantees investment security. In the new model, it is each producer's own responsibility to commercialize the produced energy. He will no longer be guaranteed to achieve a certain price. Instead he will receive a periodically changing feed-in premium (stays constant within the defined period, e.g. per quarter). That means if the producer does not sell his power, he will not be paid any subsidies. The Feed-in premium equals the difference between the strike price and the reference market price. The reference market price could for instance be the Swissix. The granting period should be shortened to 20 years. Further some plants will receive a one-off investment grant instead of the feed-in premium (BFE, 2015).

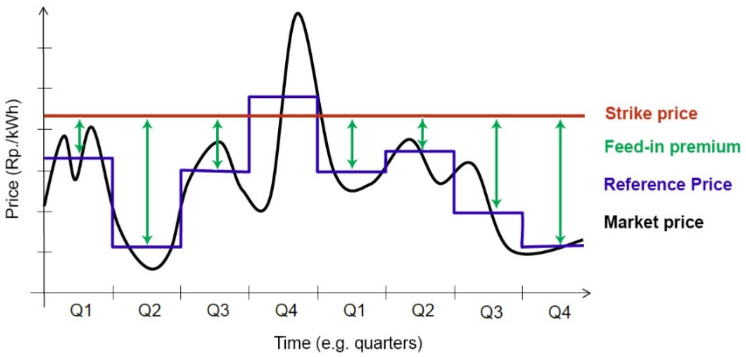


Figure 11: A more market based system for Switzerland should be introduced if possible. The feed-in premium is periodically variable and only paid out when power effectively was sold (BFE, 2015).

To determine the strike price the federal government will run auctions which will accept the second lowest bid. Plants which are already obtaining the KEV surcharge should not be affected by the new system. What the new subsidy system is going to look like in detail is still open and needs to be clarified.

3.5.1.2 One-off investment grants

One-off investment grants were implemented to support the electricity by small photovoltaic plants. The subsidies should cover at maximum 30 percent of the investment costs. Whether a one-off investment grant is provided is shown in illustration 4.2. The effective amount of the grant is linked to the output of the system and whether it is a freestanding or an integrated plant which can be learned from table 4.1 (BFE, 2015).

	Attached/freestanding plant	Integrated plant
Baseline (CHF)	1400	1800
Service amount (CHF/kW)	850	1050

Table 7: The effective one-off investment grant in Switzerland consists of two parts.

3.5.1.3 Grid surcharge refunding

Companies with a high energy consumption have the possibility to request a full or partial refund of the tariff surcharge for the promotion of renewable energies, which all consumers have to pay. The surcharge is among other income sources used to finance the KEV-surcharge, the one-off investment grants as well as open competitive biddings. Companies which have electricity costs of minimum 10 percent of their gross value added can fully claim back the surcharges if they fulfil all the eligibility requirements. Companies that have electricity costs between 5 and 10 percent of their gross value added can only partly claim back the surcharges. The amount of refunding has at least to be 20'000 CHF per annum. Additionally, the end users who are claiming back need to undertake themselves to a target agreement to increase their energy efficiency which obligates them to invest at least 20 percent of the refunded amount into *almost economical actions* within three years after disbursement. It can be applied for the refund by submitting a request at the Federal Office of Energy (BFE, 2015).

3.5.2 Germany

3.5.2.1 Feed-in compensation

In Germany, the renewable energy act (EEG) guarantees the operators of renewable energy plants to receive a compensation for their energy production per kWh for a period of 20 years. The fee depends on the technology in use and is determined periodically. Since 1 August 2014 only plants with a capacity lower than 500 kW receive the feed-in compensation. All the other fall into the direct marketing model that is explained in the next section. From 2016 on the threshold for the feed-in compensation is going to be set down to 100 kW.
From the 1 January, 2016 the feed-in compensation will be reduced by a certain percentage each year. Again, the exact amount of the percentage decrease depends on the type of technology and the capacity of the plant.
In addition to the feed-in premium and the direct marketing model the EEG also regulates the feed-in of electricity into the power grid. Operators of renewable energy plants are entitled to immediate and priority grid connection. Moreover, they have the right to immediate and priority feed-in of their whole production of electricity, as well as transmission and distribution. If necessary, grid operators are even forced to extend their grid capacity (Bundesnetzagentur, 2014).

3.5.2.2 Direct marketing

Renewable energy plants which exceed the threshold of 500 kW (100 kW from 2016 on) need to place their power production on the market by their own. Instead of a fixed feed-in compensation they can claim a market premium (MP) in cents per kWh from the grid operator in addition to the price achieved on the market. The Market Premium is calculated as following (Bundesnetzagentur, 2014):

$$MP = Max(FC - MV; 0)$$

FC = Feed-in compensation value
MV = Monthly market value

MV Equals the actual monthly mean of the market value of the hourly orders on the spot market EPEX for the price area Germany/Austria for the technologies gas, biomass, geothermal and water. Wind and solar energy have separate definitions.

Wind on-shore: Actual monthly mean of the market value of electricity from on-shore wind power plants on the spot market EPEX for the price area Germany/Austria. The value is calculated as follows:
For each hour of a calendar month the mean of the hourly orders price on the spot market EPEX for the price area Germany/Austria is taken and multiplied by the amount of produced on-shore electricity based on an online-projection. The result for each hour of the current calendar month is summed up and divided by the sum of the produced on-shore electricity during the whole month.

Wind off-shore: Same procedure as for on-shore wind power plants except that on-shore values needs to be replaced with off-shore values.
Solar: Same procedure as for on-shore wind power plants except that on-shore values needs to be replaced with solar values.

The Feed-in compensation and the market premium are not funded by the government and are paid from a separate account. The account has two streams of income. The first consist of the revenue of the renewable energy sold on the exchange and the second of the EEG reallocation charge which each electric utility company must pay per kWh delivered to an end consumer.

Figure 12: The cash in- and out-flows of the EEG reallocation account.

3.5.2.3 Grant for flexibility

Biomass power plants have the right to claim a surcharge for the flexibility installed. Thereby it is distinguished between new and existing plants. New plants receive 40 Euros for the provision of flexibility per each kW installed per year. The surcharge can be referred for the funding period of 20 years.
Plants which are brought into service before 1 August 2014 are entitled to refer a flexibility premium if they do not refer a feed-in premium but would be eligible to and the rated wattage equals at minimum 0.2 times the installed capacity. The claim for the premium is 130 Euros per each kilo Watt installed per year for the provision of flexibility. The premium is provided for ten years (Bundesnetzagentur, 2014).

The flexibility premium (FP) is calculated as following:

$$FP = \frac{P_{Additional} \times CC \times 100 \, {}^{Cent}/_{Euro}}{P_{rw} \times 8760 \; h}$$

$$P_{Additional} = P_{inst} - (f_{cor} \times P_{rw})$$

P_{rw} = Rated wattage
P_{inst} = Capacity installed
$P_{Additional}$ = Additional provided installed capacity for the demand-orientated production
f_{cor} = Correction coefficient for the load factor of the power plant

- for bio-methane 1.6
- for biogas 1.1

CC = Capacity component for the provision of additional installed power, set to 130 Euro

3.5.3 Denmark

Basically the subsidy system for renewable Energy in Denmark is designed like a mix of the KEV-model and the direct-marketing model in Switzerland. That means that the producers receive a fix strike price. This price is achieved by receiving the market price and the premium. The premium is the difference between strike price and the market price. However, there are some exceptions, and the exact definition of the so-called supplement varies along and within technologies. A technology that basically differs from the other is offshore wind power.

Moreover, there are some special regulations concerning other electricity-generating installations based on renewable energy that will not be explained here. Additional information can be found on the homepage of the Danish Ministry for Climate and Energy (Energi Styrelsen, 2013).

3.5.3.1 Wind turbines

The support of wind turbines by the government mainly depends on when the wind power plant was build or what kind of plant it is (Onshore/offshore). The relevant market price used to derive the premium equals the spot-market price on Nord Pool Spot in the actual area the power plant is connect to the grid.
Please consider that the regulations for subsidies of wind turbines installed before 21 February 2008 are not listened. Further information can be found on the homepage of the Danish ministry for Climate and Energy.

<u>Onshore wind turbines</u>
For turbines, which were installed after 1 January 2014 the owner of the plant is responsible for selling the produced energy on the market and for paying the costs this generates. In addition to the spot-price, the owner receives a premium of 0.25 DKK/kWh for the sum of 6600 full load hours and for the power generation of 5.6 MWh per m^2. The premium is reduced for every 0.01 DKK the spot-price exceeds the threshold of 0.33 DKK/kWh. Therefore, a maximum price of 0.58 DKK/kWh can be achieved. Balancing costs of 0.023 DKK/kWh are allowed and subsidized as well.
For turbines, which were installed between 21 February 2008 and 31 December 2013 the owner of the plant is responsible for selling the produced energy on the market and for paying the costs this generates. In addition to the spot-price, the owner receives a premium of 0.25 DKK/kWh for the sum of 22000 full load hours. Balancing costs of 0.023 DKK/kWh are allowed and subsidized as well.

<u>Offshore wind turbines</u>
For turbines, which were installed after 21 February 2008 the owner of the plant is responsible for selling the produced energy on the market and for paying the costs this generates. In addition to the spot-price the owner receives a premium of 0.25 DKK/kWh for the sum of 22000 full load hours. Balancing costs of 0.023 DKK/kWh are allowed and subsidized as well.

<u>Additional price premiums for factory-new wind turbines with scrapping certificates</u>
For onshore wind turbines connected to the grid between 21 February 2008 and 31 December 2011 additional price premiums are provided for the part of the production covered by a scrapping certificate based on a choice of the owner. The scrapping certificate must be from a turbine with an output of 450 kW or less and it must have been dismantled between 15 December 2004 and 15 December 2011. The premium is either: 0.12 DKK/kWh for 12000 full load hours but adjusted continuously, so that the sum of market price and premium do not exceed 0.38 DKK/kWh, or 0.08 DKK/kWh for 12000 full load hours.

<u>Household wind turbines</u>
A household wind turbine provides a production capacity of 25 kW or less and is connected within the installation of the house. The system operator sells the generated energy on the spot market. Wind turbines within households connected to the grid no later than 19 November 2012 receive a price supplement that together with the market price reflects 0.60 DKK/kWh.
For wind turbines within a household connected to the grid after 20 November 2012 receive a price supplement that together with the market price reflects 0.60 DKK/kWh.
If the wind turbine's power production is less or equal than 6 kW and it got connected to the grid between 20 November 2012 and 31 December 2013, the total amount of supplement and market price is 1.30 DKK/kWh.
If the wind turbine's power production is less or equal than 6 kW and it got connected to the grid after 1 January 2014, the total amount of supplement and market price is 1.30 DKK/kWh. However, the supplement is reduced annually by 0.14 DKK/kWh during the period from 1 January 2014 to 1

January 2018. The price supplement is provided until the plant is 10 years old since the grid connection.

3.5.3.2 Biogas plants

Electricity generation from biogas and gasification gas generated from biomass
For power produced only from biogas and gasification gas generated from biomass, a price premium is provided. The premium together with the market price represents 0.793 DKK/kWh. The sum of these two is adjusted by 60% of the net consumer-price index each year.

If the output of the plant is equal to or less than 6 kW, and if it was connected to the power grid from 20 November 2012 to 31 December 2013, there is the option to receive a premium that together with the market price represents 1.30 DKK/kWh.

If the output of the plant is equal to or less than 6 kW, and if it was connected to the power grid from 1 January 2014, there is again an alternative for the price premium. The premium together with the market price reflects 1.30 DKK/kWh but it is reduced by 0.14 DKK/kWh each year between 1 January 2014 and 1 January 2018. The price supplement is provided until the plant is 10 years old since the grid connection.

In addition to the subsidies mentioned above there are two further premiums for biogas plants. One is 0.26 DKK/kWh and the other 0.10 DKK/kWh. The first one is from 1 January 2013 annually adjusted downwards by 0.01 DKK/kWh for each DKK/GJ of the amount by which the natural gas price of the previous year exceeds a basic price of 0.532 DKK/GJ. If the gas price falls below the basic price the subsidies will be adjusted upwards. The premium of 0.10 DKK/kWh will be reduced by 0.02 DKK/kWh each year from 2016 up to 2020 when it will be phased out altogether.

Electricity generation from biogas and gasification gas generated from biomass, as well as from other types of fuel

For power produced only from biogas and gasification gas generated from biomass as well as from other types of fuel there is a price premium provided. The premium together with the market price represents 0.431 DKK/kWh. The sum of these two is adjusted by 60% of the net consumer-price index each year.

Owners of a biogas plants can choose whether they receive the supplement which together with the market price represents 0.793 DKK/kWh (see above) or the supplement of 0.431 DKK/kWh for the part of the electricity generated from the biogas and/or the gasification gas. The choice must be made at the beginning of a new year and it is binding for one year.

As for the biogas production described under chapter 4.2.1 there are the same two additional price premiums of 0.10 DKK/kWh and 0.26 DKK/kWh. The way they are used is the same.

3.5.3.3 Photovoltaic installations

Photovoltaic installations equal to or smaller than 400 kW
All photovoltaic plants that were connected to the grid between 20 November 2012 and 31 December 2013 receive a premium which together with the market price reflects 1.30 DKK/kWh. The same amount is provided to all installations after 1 January 2014 with the difference that the premium is reduced annually by 0.14 DKK/kWh until 1 January 2018. The premium is provided for 10 years from the date of grid connection.

Photovoltaic installations bigger than 400 kW
For photovoltaic plants connected to the grid after 20 November 2012 a price supplement is paid for 10 years that together with the market price represents 0.60 DKK/kWh and for the subsequent 10 years 0.40 DKK/kWh. The system operator sells the power produced on the spot market.

Collective photovoltaic installations

Collective photovoltaic plants that were connected to the grid between 20 November 2012 and 31 December 2013 receive a premium which together with the market price reflects 1.45 DKK/kWh. The same amount is provided to all installations after 1 January 2014 with the difference that the premium is reduced annually by 0.17 DKK/kWh until 1 January 2018. The premium is provided for 10 years from the date of grid connection.

3.5.4 Norway

There is no such a thing like feed-in tariff in Norway. Instead, on 1 January 2012, the Swedish and Norwegian government implemented electricity certificates what reflects an economic subsidy system. It works like a premium for renewable energy sold and should support investments into renewable power plants. The concept was introduced by the *Green Certificates Act*. In addition to electricity they also made a committed to increase the common power production out of renewable energies by 26.4 TW (each 13.2 TW).

Power producers of renewable energies in Norway can apply for certificates which they will receive for free per each MWh produced. These certificates again are sold to power suppliers and industrial producers. They are obligated by law to buy them to a certain proportion of their electricity sales or usage. Thus, this law creates an artificial demand for the electricity certificates so the producers receive a premium for producing green energy. The following producers are authorized to apply for electricity certificates assumed they fulfil all the other requirements (KPMG, 2014):

- Power plants using renewable energy sources and built after 7 September 2009
- Hydro plants generating 1 MW and built after 2004
- Existing renewable power plants which permanently increase their electricity production with new construction beginning on or after 7 September 2009

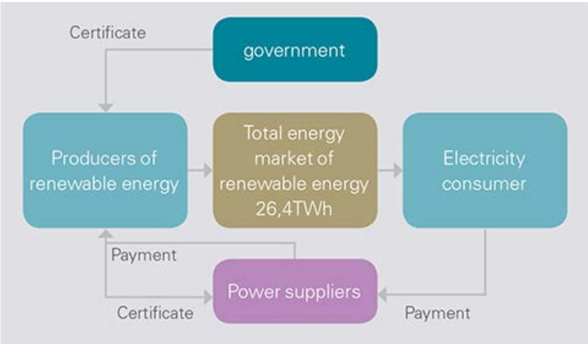


Figure 13: The subsidies scheme in Norway makes that eventually the end consumers pay for the electricity certificates (KPMG, 2014).

3.6 Grid tariffs

3.6.1 Switzerland

The costs of the transmission grid are allocated to the Distribution System Operator (DSO) and the end consumers directly connected to the transmission lines. It is a uniform tariff that must be paid to the Swiss TSO Swissgrid. The tariff is based on the flexible components power obtained and energy consumed/produced, as well as the fix component annual connection fees. The costs are passed on fully to the end-consumers. Consequently, DSO tariffs include the TSO tariffs so that the end-consumer pays for both transmission and distribution. The detailed fees of Swissgrid can be found in Annex A.

The DSO grid tariff in Switzerland has basically the same structure like the TSO tariff. The two variable elements are: the maximum power obtained (peak load) and the amount of energy consumed/produced. Hence, by reducing the maximal consumption of power over a month (peak-shaving/load-shifting) and by consuming less energy, the grid costs can be minimized.

The number of DSOs in Switzerland is high and each of them has its own grid tariff. The grid tariffs charged by each DSO need to be approved by the governmental authority ELCom. The approach is cost based, which means that the tariff is approved if it reflects the DSO's claimed grid related OPEX and CAPEX. In most other European countries, the grid tariffs of the DSOs are determined by a benchmark system (efficiency boarders). Those systems include incentives for tariff reductions, which is in the Swiss system barely given. Because of the loose tariff system and the large number of DSOs in Switzerland, inefficiency is high and huge price differentials between the individual DSOs exist (Cuderman, 2014).

3.6.1.1 Germany

The basic structure of the grid tariffs for DSOs in Germany is the same as the ones in Switzerland. The tariffs consist of an energy, a variable and a fixed component. The differences between the two countries lies in the regulation of the grid tariffs, as already mentioned above. Whereas in Switzerland the tariffs need to be approved by the responsible authority, a revenue cap is implemented in Germany. With an elaborated procedure, the costs necessary for operations are checked and the revenue cap determined. The fixed revenue provides an incentive for the DSOs to increase the efficiency and thus their return. The revenue cap can be decreasing over time so that the efficiency gained guaranteed will be shared between DSOs and the end-consumers (Bundesnetzagentur, 2015).

Germany has four different TSO and they all have different tariffs. Again, the underlying structure is the same and the they are meant to cover the grid and balancing costs of each TSO.

3.6.2 Denmark

The Danish TSO spits is electricity tariffs into system, grid and PSO tariffs. System tariffs reflects all the costs related to security and quality of supply, while grid tariffs cover the operation and the maintenance of the transmission electricity grid. The PSO tariff covers all the subsidies for renewable energies as well as research funds.

The tariff is applied on the energy consumed/produced (per kWh). Hence, the power aspect is ignored. The peak load of a unit connected to the grid does not affect its payment even though the grid is built for that peak hour (Energinet.dk, 2016).

Similar to Germany, the Danish regulatory authorities also set revenue caps for DSOs. The DSOs therefore can set the tariffs after their own scheme if they are in allegiance with the Danish Electricity Act. The Act says that the tariffs must be set fair, objective and in a non-discriminatory manner. The tariffs follow the principle of cost allocation and usually is split into an energy and a fixed component. A capacity element is missing in the Danish grid tariff. To consider peak-hours in the tariffs, the Danish Energy Association recommends in the Electricity Industry Guidance to implement a time-of-use component for the DSOs. The suggested model is simplified with the intention to allow the DSO to test the new time-of use approach (NordReg, 2015).

3.6.3 Norway

The Norwegian grid tariffs on the transmission level are similar to Germany and Switzerland based on an energy, a fixed and a power component. The speciality of the Norwegian systems lies in the way the actual cost is calculated. There are different tariffs for consumption and production.

Moreover, the tariff is not just simply multiplied by the quantity produced or consumed. The effective costs are based on the consumption patterns. The details of how to calculate the costs can be found in Annex A (Statnett, 2016b).

On the DSO level the tariffs are more align with the Danish approach. An Energy and Power component are incorporated but not capacity. For the industry, power tariffs are sometimes used. However, there is an ongoing debate in Norway about the DSO tariff design. The general opinion is that Norway should have less energy-based and more capacity-based tariffs. In addition, Energi Norge has installed a working group dealing with the design of DSO tariffs. Policy changes are expected soon (NordReg, 2015).

3.7 Retail Market Tariffs

In Switzerland exist about 800 different energy suppliers and each has his own electricity tariff calculation model for its customers/households. Hence, it is not possible to define an overall formula. Nevertheless, there is a common pattern along all the suppliers. This allows to identify the components that relevant to minimize the electricity end bill.
The grid costs in Switzerland are allocated by a costs-by-cause principle as explained in Chapter 3.6. In general, the tariff consists of three elements: the grid tariff, the energy tariff and taxes and fees (see Figure 14). The latter one is fix and thus cannot be controlled. Its exact composition varies along each municipality. From an optimization perspective, the tax and fee component is not of major significance. The energy tariff depends on the time of day and accounts for the effective amount of electricity consumed (time-of-use). Consumption can be shifted from times of high prices to times of low prices reduce the costs. The greater the time-price differential, the more important this aspect of becomes for the optimization.

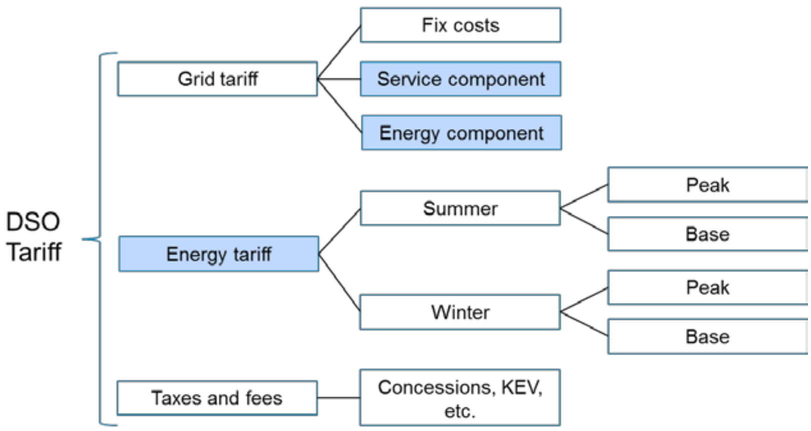


Figure 14: Energy supplier tariff structure in Switzerland.

The last part constitutes the grid tariff. It considers for the costs that arise through the power transmission from the produces to the consumer. It can again be split into three blocks. The first block is fix costs which is mostly calculated per joint and cannot be influenced by optimizing the purchase of electricity. The second block is a service (power) component and is not always considered for households. It is a compensation for the grid operator for the provision of service which is shifted from grid level to grid level until the original causer of the costs. Its amount is determined by the peak in power consumption for each month/year based on the quarter-hour mean (kW/Month). This component is not very often included into the grid tariffs. The energy component compensates the grid operator for the provision of power delivery and is also passed from the grid operators to the causers. It depends on the effective amount of energy consumed (kW/h).

Consequently, it can be said, that the significant elements for an optimization of a household are the energy component and the energy tariff. For business clients, the service component becomes relevant as well.[7] The electricity price for households in Germany has basically the same components as in Switzerland.

The same is the case in Norway and Denmark. End consumers usually are only charged per kWh and do not have to pay for the capacity required. On an industry level in all four countries except Denmark it is common to split the grid cost into a capacity (service) and an energy component. Also, there are many pilots about grid in various European countries running. The different projects try test new grid tariff models that allocates the grid cost more towards its causer and set incentives to reduce load peaks (Euroelectric, 2013). Norway is even currently considering changing their grid tariff structure towards a capacity regime (Fiksen, 2015)

A theoretical Norwegian study conducted whether grid tariffs can be used to reduce or postpone grid investments. To achieve the desired effects, the study considered dynamic price signals. The results showed that dynamic grid tariffs may reduce grid costs by one to three percent on average. On an individual grid company basis, the potential can be substantially higher. This implies efficiency gains and can have simulating impacts on the development on new businesses (Euroelectric, 2013).

In conclusion, we can see that the grid tariffs do not provide much incentives for load shifting. The current energy grid component in the tariffs maximal provides incentives for energy savings. However, there are many indications that this could change in the close future and the conditions for active DR will improve.

3.8 Trends

In this section, we are going to outline the most recent developments in electricity markets. Certain technologies and trends are already leading to significant adjustments in our everyday life and effecting power markets. For an understanding of possible future market frameworks, it is essential to identify those movements and analyse their possible consequences.

3.8.1 From smart metering to household flexibility

Many European countries have created roadmaps for a nationwide installation of smart meters. Also in Switzerland, there is currently a debate whether such an obligated rollout should be adopted. It seems as a matter of time until Smart Meters will be integrated in households by default. That is good news for the exploitation of flexibility (EC, 2016).

Firstly, Smart Meters will allow to provide a new tariff system for the retail market which could be coupled with the wholesale market prices. This again will be a motivation for households to adjust their consumption pattern to the current production and thus for peak-shaving. Currently it does not make any sense to shift your consumption except from day to night because tariffs are fixed. Even though the financial incentive will be too small to bring the energy transition about, Smart Meters will still play an important role in making use of household flexibility. They provide an enormous amount of data about the whole behaviour of their customers to the energy suppliers. They may be able to develop new business models or other incentives that will allow to steer power consumption.

Secondly having installed a Smart Meter in every single household will facilitate the rollout of a Smart Gateway for companies. On one hand, there would already be a component in place which provides the data needed for a Smart Gateway that again can control devices such as heating, heat pumps or solar panels. On the other hand, it lowers the threshold of acceptance for an intervention in private houses. As the metering of power consumption is confronted with data privacy questions, an obligation by law would avoid the resistance of people due to privacy concerns about the installation of a Smart Gateway. It can be said that the introduction of default Smart Metering definitively would support to make use of household flexibility. Therefore, a legal framework like the one mentioned above is of great importance for the realization and success of a project like SEMIAH.

[7] Clients with a power consumption greater than 100 MWh/a can negotiate an own concept for the pricing of their power supply with the energy suppliers.

It is a clear strategy of many electric utilities supplier to get access to their customer's flexibility via those. Energy suppliers simply provide their customers additional benefits if the customers give them their information about their energy consumption.

3.8.2 Electric Vehicles

When talking about big trends, we cannot leave out electric vehicles (EVs). There has been a big turnaround in the car manufacturing industry. Starting with Tesla, almost all car brands have now EVs in their product portfolio. Sales of EVs are growing. As we can see in Table 1, 2010 the market share of EVs and plug-in hybrid (PHEV) has been close to zero percent. In 2015, the share was already close to one percent (1,2 million EV) and is said to increase a lot within the next few years. Half of the EVs that were on the road by the end of 2015 have not existed in 2014. In some countries like Norway and the Netherlands the share of electric cars has already reached more than 23% respectively 10% thanks to radical EV policies (IEA, 2016).

Table 11 ● Electric cars (battery electric and plug-in hybrid), market share by country, 2005-15

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Canada							0.0%	0.1%	0.2%	0.3%	0.4%
China						0.0%	0.0%	0.1%	0.1%	0.4%	1.0%
France							0.1%	0.3%	0.5%	0.7%	1.2%
Germany							0.1%	0.1%	0.2%	0.4%	0.7%
India						0.0%	0.0%	0.1%	0.0%	0.0%	0.1%
Italy								0.0%	0.1%	0.1%	0.1%
Japan					0.0%	0.1%	0.4%	0.5%	0.6%	0.7%	0.6%
Korea							0.0%	0.1%	0.1%	0.1%	0.2%
Netherlands						0.0%	0.2%	1.0%	2.5%	3.9%	9.7%
Norway				0.2%	0.1%	0.3%	1.5%	3.2%	5.8%	13.7%	23.3%
Portugal							0.1%	0.1%	0.2%	0.2%	0.7%
South Africa											0.1%
Spain							0.1%	0.1%	0.1%	0.2%	0.2%
Sweden							0.1%	0.3%	0.5%	1.4%	2.4%
United Kingdom							0.1%	0.1%	0.2%	0.6%	1.0%
United States						0.0%	0.1%	0.4%	0.6%	0.7%	0.7%
Others*							0.0%	0.1%	0.1%	0.3%	0.7%
Total**				0.0%	0.0%	0.0%	0.1%	0.2%	0.3%	0.5%	0.9%

* Austria, Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, Greece, Hungary, Iceland, Ireland, Latvia, Liechtenstein, Lithuania, Luxembourg, Malta, Poland, Romania, Slovak Republic, Slovenia, Switzerland, Turkey.

** The total market share is calculated for all the countries covered above.

Table 8: The shares of electric vehicles in a group of selected countries from 2008 to 2015 (IEA, 2016).

The global share of EVs is said to cross the 10% line within the next 10 years and will then even grow faster once the 10% threshold is reached (Table 7). Comparing this with historical growth rates, this does not seem impossible. The estimated growth rates even seem pessimistic compared to the historical ones (IEA, 2016).

Certainly, this has implications for the grid and the electricity markets. First, a strong increase demand for electricity is not to avoid. The additional demand must be covered by renewables. If that is not the case, we will increase the CO2 emissions instead of cutting them down. Hence, electric cars will increase the pressure on the production side. Also, the grid will be challenged even more. Through the charging of EVs, especially the superchargers, additional peaks of electricity consumption will appear if the charging is not managed smartly. Those peaks can lead to additional investments and destroy the whole DR effects that will be created by SEMIAH. A Tesla Wall Connector single charger has a capacity of 10 kW and a dual charger even 20 kW. To fully charge a Tesla Model S 92.1 kWh are needed. Assuming a four-people household consumes between 4000 and 8000 kWh a year[8], we can see how big the impact of an EV will be on the electricity consumption. (Tesla, 2016).

[8] Electricity consumption varies a lot among and within countries. However, the exact number will not matter to prove a Tesla will have an enormous effect on residential electricity consumption.

Consequently, EVs are of great importance for DR. Not only can EVs ruin some of the possibilities of DR bring about, they also are a potential for new business models. Hence, for all the simulation results we must consider the effects EVs will have on the grid and discuss how an outcome with an EV could be different.

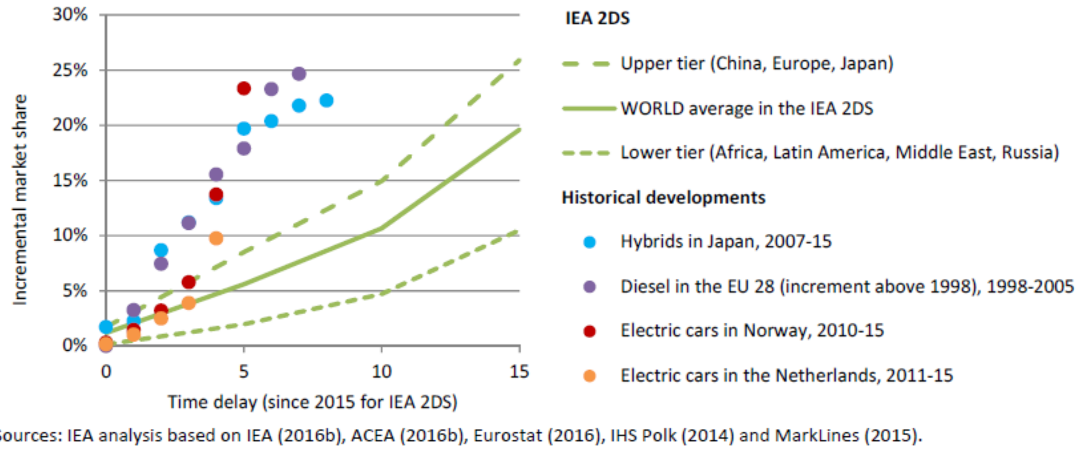


Figure 15: The market share required to fulfil the IEA 2DS targets in comparison with some historic developments in selected countries are pictured here. We can see that the incremental market share growth required to reach the targets, lies below the development of previous rapid changes in similar fields (IEA, 2016).

3.8.3 Electricity Storage

Electricity storage technologies have made a lot of progress in the last few years and have become much cheaper. This is changing the expectations and behaviour of many players in the market. The possibility to store electricity brings many opportunities about. Utilities can improve grid performance and reliability, as well as avoid investments into peaking generation capacity. End-consumers can use storage systems for local and decentralized production and the harmonization of supply and demand. Even though the systems are not fully matured yet and still expensive, the changes happen rapidly so that energy storage will become a key element in energy transition (Deloitte, 2015).

The most famous current attempt to commercialize batteries for end-consumers is Tesla with the Powerwall battery. With a capacity of almost 7 kWh it is meant for households. It was launched in the beginning of 2016 and a new version should be announced by Tesla towards the end of Summer 2016 (Tesla, 2016). Tesla is not the only vendor of home-batteries. Their opponents Stem and Code are also offering battery solutions for households.

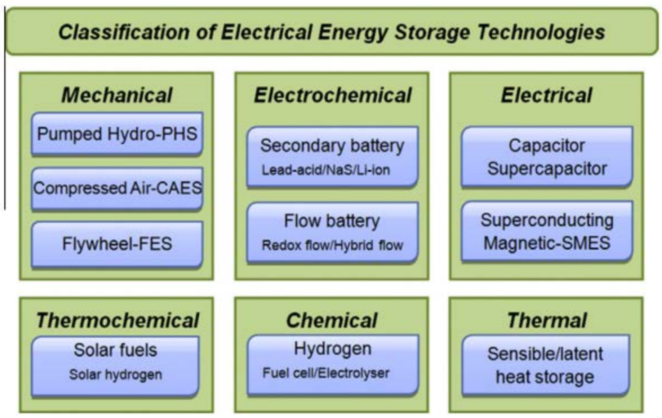


Figure 16: Classification of EES technologies by the form of stored energy (Luo, Wang, Dooner, & Clarke, 2015).

The electrochemical Lithium-ion batteries are the most used for smaller devices such as Phones, EVs and homes. This is thanks to its relatively high energy density. However, this is not the only way to store electricity. Other storage types such as mechanical, electrical, thermochemical, chemical and thermal exist (compare Figure 16Figure 1). Each of them has different characteristics and is used for purposes that fits its properties. The most spread large-scale storage technology is Pumped Hydro Storage (PHS). Especially in Europe, most feasible PHS projects are already realized. Only a limited number of suitable sites are left. That will not be enough to solve our energy problem and thus, PHS is not the solution. Storage sites of other storage technologies are already operating, even with quite high capacities. Unfortunately, most of them are research projects and they would not be economically feasible. Besides the problem to commercialize the technologies, the composition of required materials is also a big issue. A lot of the substances in batteries are poisonous or rare. A combination of different technologies helps to meet the criteria of most power systems but not the commercial aspects yet. Therefore, we still rely on major improvements and breakthroughs in R&D (Luo, Wang, Dooner, & Clarke, 2015).

3.8.4 Internet of Things

In the last few years, IoT has become a huge topic and an important source of new disruptive business models. The expression internet of things stands for connecting technical devices to the IoT. Those devices can then be controlled or used for data collection. Forbes (2014) defines the internet of things as follows: *"Simply put, this is the concept of basically connecting any device with an on and off switch to the Internet (and/or to each other). This includes everything from cellphones, coffee makers, washing machines, headphones, lamps, wearable devices and almost anything else you can think of. This also applies to components of machines, for example a jet engine of an airplane or the drill of an oil rig… The relationship will be between people-people, people-things, and things-things."*

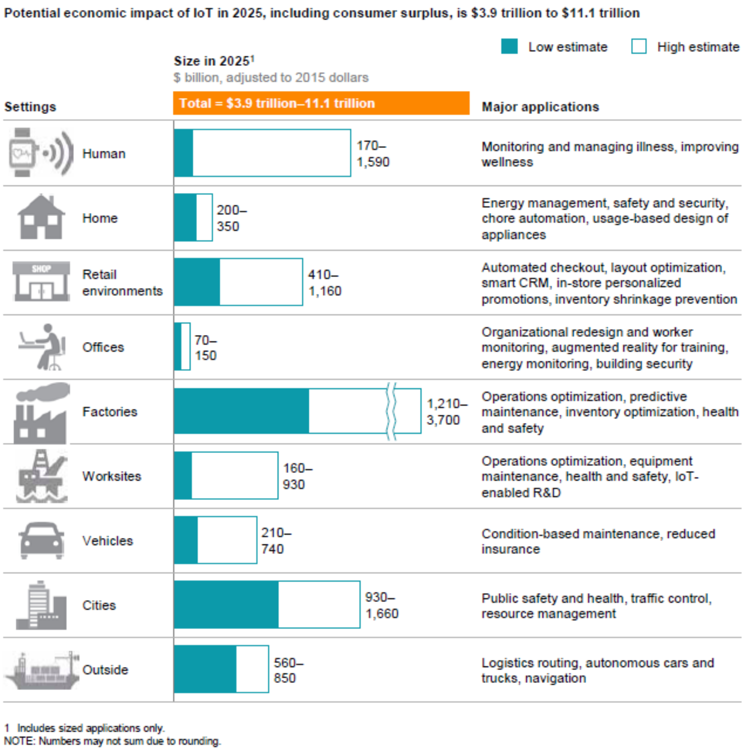


Figure 17: Estimate of the economic impact of IoT per Industry in 2025 (McKinsey Global Institute, 2015).

The potential of IoT is huge and there are no limits to the field it can be applied in. However, the economic value is not clear for everything but IoT definitively is strongly going to affect our future. Also in the energy industry IoT brings many new opportunities and drives innovation. Automatic DR is based on IoT, since it actively controls devices in industry or households based on measurement points and other input data. SEMIAH is nothing else than an IoT application. Additional installed devices turn conventional houses into smart buildings that can adjust their consumption behaviour. IoT can not only be implemented in households. It will be important for decentralized energy generation as well as for traditional power plants. The continuous and remote monitoring gives power generation the chance to increase their efficiency and lower maintenance and investment costs.

The economic potential of IoT is huge and estimated to $3.9 trillion to $11.1 trillion for all industries by 2025 (compare Figure 17). It will change basic principles of competition and allow to create totally new business models for user and supply companies (McKinsey Global Institute, 2015). E.g. energy suppliers will be able to provide new services to their customers. In liberalized electricity markets, this will be a key element for creating customer loyalty. End consumers might no longer only will chose their supplier based on price. Other components such as smart building services will gain importance. It can already be observed in the SEMIAH companies that energy suppliers and grid companies have started acquiring increasingly smaller service companies and startups to diversify their product portfolio to create new sources of income. Energy prices are low and the integration of markets drives competition.

3.8.5 Increasing Price volatility?

Even if it had been predicted otherwise, electricity prices have decreased over the last few years and the pressure on the profitability of power plants put on. Looking at Figure 18 the downwards trend in electricity prices can be seen easily. Even though there is quite a huge jump upwards from 2007 to 2008, afterwards prices have decreased steadily from year to year. Remarkable is especially the huge difference between 2013 and 2014 where the prices became significantly lower. A highly important question for all power market players of course is whether the negative trend will continue. Since whole Europe is pushing a completely liberalized and harmonized power market the obvious answer for that question would be yes. The market-opening would lead to more competition and that again to lower prices.

However, things are not that simple. Simultaneously the pressure forms the demand side is growing as well. More and more devices require electricity. For example, a world with only electric cars would increase the need for additional power sources. Demand per capita would be a lot higher than now at a single blow. Consequently, prices would have to increase. The two effects work in opposite direction, so that the total effect would be unclear. In addition, it is also opaque how the supply side is going to develop. All that results in a lot of uncertainty what makes it hard to speculate about the future price development. Another point that makes it even harder to submit a statement with hindsight to electricity prices is that the whole electricity industry finds itself at a crossroad.

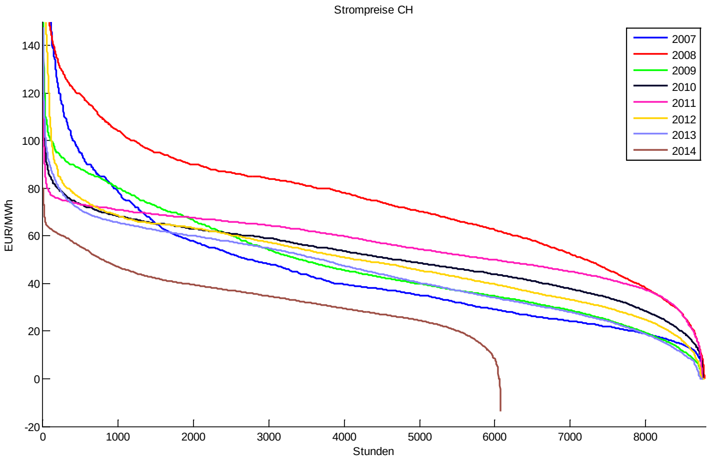


Figure 18: The price duration curve of Swiss electricity prices shows that prices have decreased a lot over the past few years in Switzerland.

Another conspicuity is that the electricity price curves, as shown in Figure 18, are relatively flat. Price-elasticity is quite small. Even though somebody submits an order to purchase power for many hours in a row, he does not have to pay much more per MWh than if he wants to purchase power only for a few hours. According to the Energy & Climate Division of the Institute for Applied Ecology in Berlin this is going to change in the future. Looking at Figure 19, we can see that price elasticity clearly is said to grow a lot until 2045. This could be an indication for more efficient markets thanks to the power market liberalization. Power Prices here are calculated based on the Power Flex model which the institute developed itself. The Power Flex Model evaluates the operation of power plants and the resulting revenues and power prices. The special feature of the model is that it considers flexibility of electricity demand and supply.

Regarding to flexibility this conclusion of the Power Flex Model promises flexibility to gain in value. As price elasticity will increase over time, end-consumers are interested to shift their electricity purchase from times of high prices to times with low prices. That again awards value to flexibility. Once flexibility has increased its price, it will be much easier to balance the demand and supply side of the power markets. With hindsight to the market opening, one possible statement for the prediction of the Institute for Applied Ecology could be that liberalization will support an efficient and well-playing market. Further insights regarding the value of price volatility will be provided in the SEMIAH simulation in Chapter 5.4.

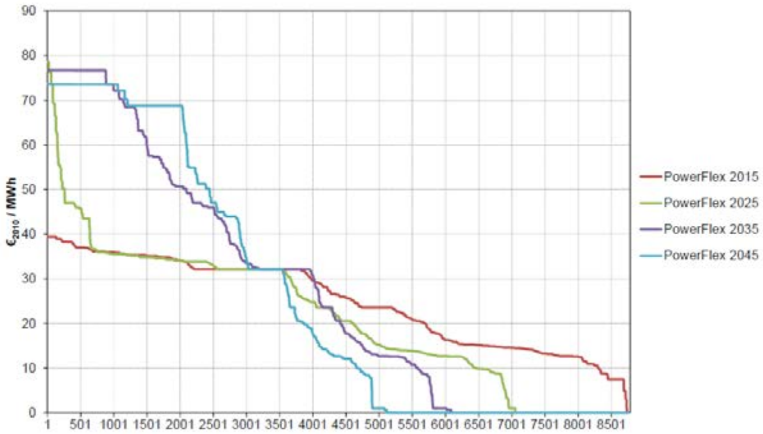


Figure 19: The PowerFlex from the Institute for Applied Ecology states that power prices will become much more elastic in the future. This would lead to an increase in prices for flexibility (Source: Institute for Applied Ecology, Berlin).

4 Future Market Frameworks and Business Cases

One objective of D9.2 is to derive feasible business models and assess potential market frameworks for the future. Before we will quantitatively asses the different opportunities in Chapter 5, a qualitative introduction into existing and newly derived models is provided. As a starting point, we are considering the future market framework USEF and its mechanisms. Next, we are summing up the three different data handling approaches by the smart grid coalition. The last two sections of this chapters will introduce business layers and market scenarios, derived by SEMIAH and building on USEF. The concepts will be further assessed in Chapter 6.

4.1 USEF a new framework: Market Design

In D 2.3 we have already been introducing USEF. USEF is a potential future market framework that focuses on the integration of decentralized electricity production and more volatile markets. The simulations that will try to estimate the value of flexibility are going to be based on the market design of USEF. Therefore, this chapter will explain the operating regimes and the market coordinating mechanism (MCM) of USEF. The USEF mechanisms show an example of how flexibility markets can be dealt with in the future. Even though, it is difficult to apply one market model for all countries, USEF provides a solid base for the implementation of flexibility markets. AS of now, USEF is one of the most elaborated and realizable market frameworks. For other more details about USEF please consolidate D2.3. The whole section is based on USEF (2015).

4.1.1 Operating Regimes

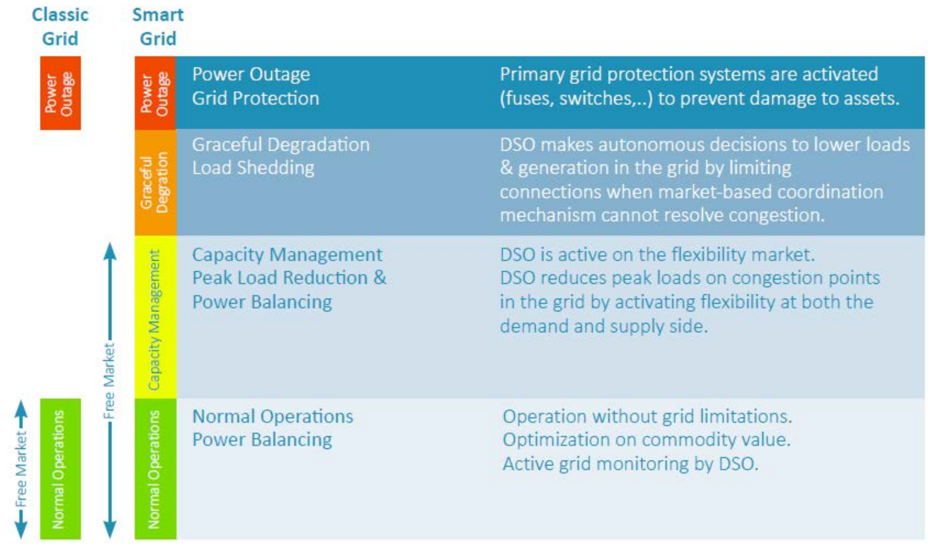


Figure 20: The USEF operating scheme is among four different operation phases from green to red. Depending on the market regimes, different levels of balancing mechanisms are used (USEF, 2015).

In USEF four different operating regimes are guaranteeing the grid stability. The green and yellow regimes are regulated by the MCM and therefore by the free market. Aggregators provide flexibility for DSOs and BRPs to avoid grid congestion. In case not enough flexibility is available, the system will go over to the orange operating regime. The DSO will have the right under the orange regime to overrule the market and limit connections to avoid a blackout.

To successfully manage the stability of the distribution grid, congestion points must be identified. The DSO will do so based on trends of energy flows in its grid. The congestion points will be published for the Aggregator so he has time to approach its customers and can provide enough energy that the DSO can manage the yellow regime.

4.1.2 MCM Phases

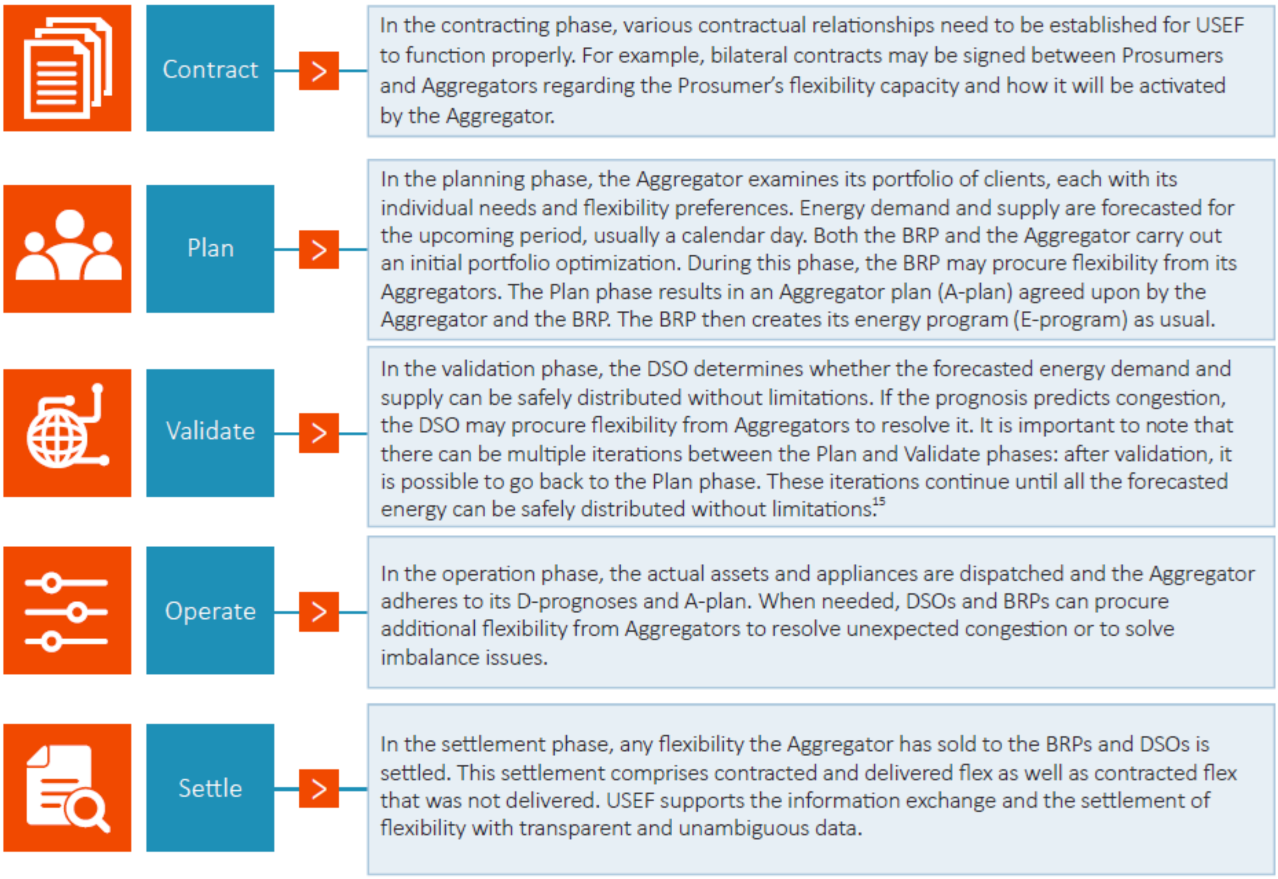


Figure 21: The different MCMs in the USEF framework (USEF, 2015).

The idea of the MCM is to optimize the utilisation of the grid capacity and to give the stakeholder the maximum amount of flexibility in organising their energy purchases before the actual delivery takes place. The process is iterative so that the time scale will vary from several months until just a few hours before delivery. The large timeframe gives the stakeholders the possibility to use all different markets such as forward market, day-ahead market and the intraday market. USEF suggests that the closing-time of the trading window should be defined by a national regulatory entity.

4.1.2.1 Contracting phase

The following contracts are foreseen to implement the USEF interaction model:

- Flexibility purchase contract between Aggregator and Prosumer to determine the conditions for DR and the settlement for the provided flexibility.
- Framework contract between supplier and Aggregator to determine the operating conditions for DR as defined in the flexibility purchase contract above.
- Flexibility service contract between Aggregator and BRP to determine the restrictions the Aggregator to offer its flexibility to the BRP, to define how it must be dealt with imbalances caused by DR and to define how the changes in the procurement for the supplier must be considered.
- Connection contract to define the load shedding in the orange phase of the DSO.

The following three contracts are optional:

- Long-term flexibility contracts between the DSO and the Aggregator to secure a certain level of flexibility over a long-term.
- Long-term flexibility contract between the Aggregator and the BRP.
- Contacts between Aggregators and ESCo and Prosumers. The contracts will be depending on the type of service the ESCo offers.

4.1.2.2 Planning phase

The aim of the planning phase is to find the economic optimum that meets all the demands of the Aggregator and the BRP. The outcome for the Aggregator is an A-plan that can be compared to the current E-programs of the BRP. In contrary to the E-program the A-plan does not have to be balanced.

In the planning phase, the Aggregator collects his prosumer's forecasts and optimizes its own portfolio including the value of flexibility. The optimization is based on its customer's needs. Hence, the Aggregator may optimize the households self-supply. The result of the whole process is the A-plan, which is proceeded to the BRP. In case forecasts change or the situation changes otherwise, the Aggregator will reoptimize his portfolio and send out an updated A-plan.

In a similar way like the Aggregator, the BRP also optimizes his portfolio of Producers, suppliers and Aggregators. The BRP negotiates with his Aggregators to exploit their flexibility in the market and maximise its value. One such as case could be that differences in day-ahead prices make it worth to shift supply or demand in time. The Aggregators would then provide their flexibilities and adjust their A-plans. Eventually, when the Aggregator's A-plans are in alliance with the BRP's portfolio the so-called E-program is created.

The DSO defines the congestion points during the planning phase. The process of defining the markers for congestion will not take place as the other mechanisms during the planning phase. They will only be defined a few times a year. If a congestion point becomes active, the regarding Aggregator can decide if he would like to offer and sell his flexibility to the DSO.

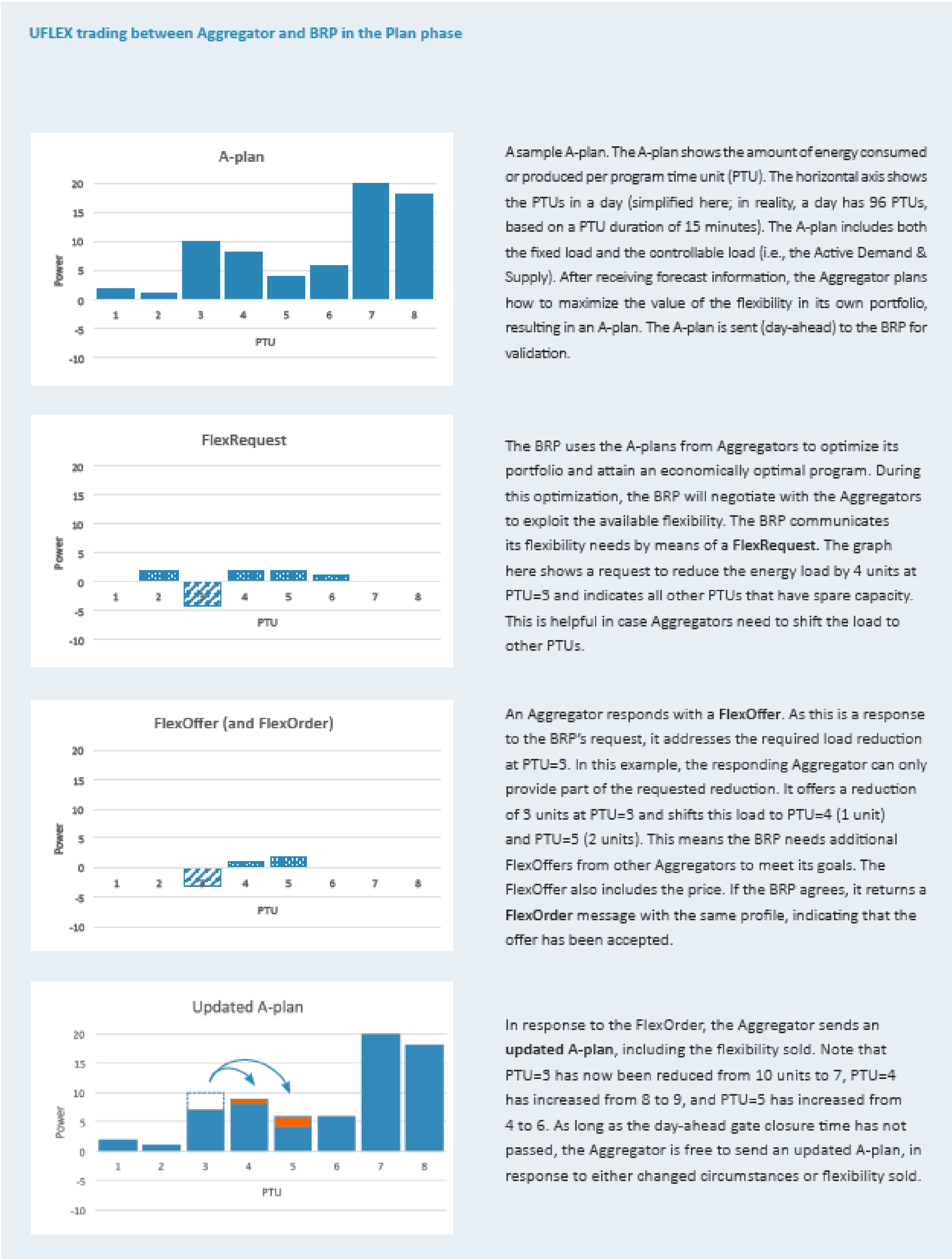


Figure 22: Trading of flexibility between the Aggregator, the BRP and the DSO according to USEF (USEF, 2015).

4.1.2.3 Validation Phase

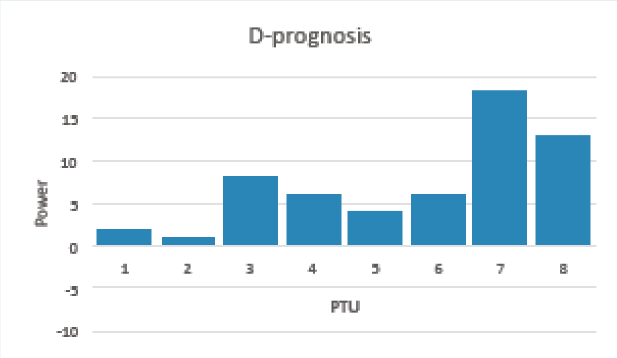
The Validation phase consists of two processes that are executed parallel: The Validate-D and the Validate-E. The two processes validate weather or no the D-prognosis created at the beginning of the validation phase and the draft E-program do not validate the DSO's and the TSO's grid constraints. The validation of the E-program is an already existing process and will not change under USEF.

In the beginning of the Validate-D, all Aggregators create a D-prognoses for each of their active congestion points based on the A-plan. All the D-prognoses are accumulated by the DSO and combined with the connections not served by an Aggregator. The DSO can then perform a grid safety analysis to check if USEF moves to the yellow regime and needs to procure flexibility on the market. If there is not enough flexibility available to avoid the expected congestion, the system moves to the orange regime.

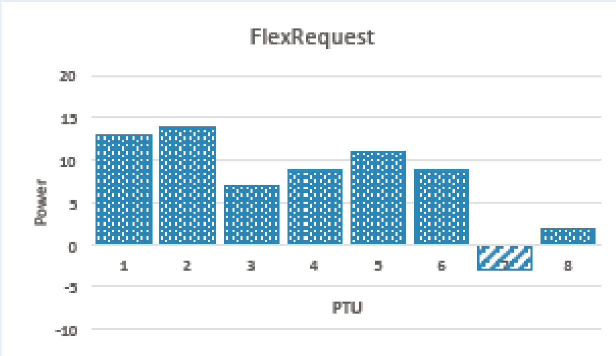
Since the DSO can procure flexibility, the validation phase and the planning phase must be iterative so the Aggregator can adjust his A-plan if necessary. To which extent the Aggregator can do that depends on his contract with the BRP. By the time the trading window closes, the Aggregator is responsible that all issues are resolve and the A-plans and D-prognoses are in alliance.

Eventually, the DSO must build a T-prognoses that will be sent to the TSO. Therefore, the DSO must combine the D-prognoses with all the forecasts for all connection points in his system that are not congestion points.

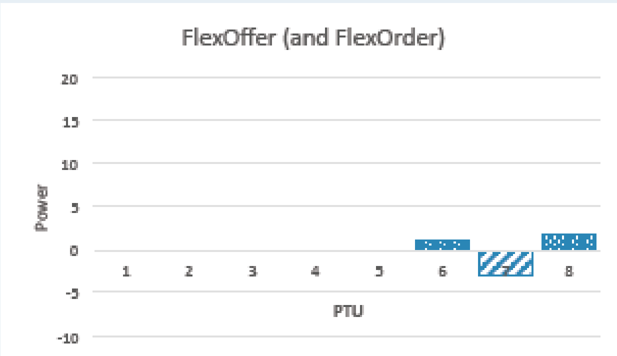
UFLEX trading between Aggregator and DSO in the Validate phase



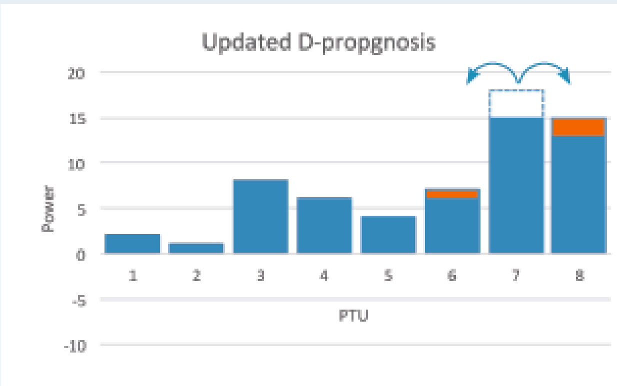
A sample D-prognosis. The D-prognosis shows the amount of energy consumed or produced per PTU at a given Congestion Point. Once it has the final A-plan at the end of the Plan phase, the Aggregator derives D-prognoses for each Congestion Point and sends them to each DSO. The DSO then states whether the D-prognosis is accepted. In the event of congestion, the DSO can use UFLEX to resolve the problem.



Assume grid capacity is limited. In this example, the DSO is faced with congestion at PTU=7. The DSO sends a FlexRequest to all Aggregators active at this Congestion Point indicating a need for load reduction at PTU=7. The message also indicates the available capacity at other PTUs.



An Aggregator responds with a FlexOffer including a price. As this is a response to the DSO's request, it addresses the required load reduction at PTU=7. In this example, the Aggregator is able to offer the requested load reduction in full. Nevertheless, other Aggregators may also make an offer, perhaps at better prices. Our Aggregator proposes to shift the load to PTUs 6 and 8. If the DSO agrees, it returns a FlexOrder message with the same profile, indicating that the offer has been accepted.



In response to the FlexOrder, the Aggregator sends an updated D-prognosis, including the flexibility sold. Since the new D-prognosis gives rise to a changed profile, USEF returns to the Plan phase, where the Aggregator reoptimizes its portfolio and, if needed, renegotiates with the BRP. Renegotiation is not always required; it is quite possible that the changed D-prognosis can be accommodated within the Aggregator's portfolio, leaving its A-plan untouched. The iterative loop over the Plan and Validate phases may continue until gate closure.

Figure 23: The validation phase of USEF is ensuring that the DSO's and the TSO's gird constraints are not violated (USEF, 2015).

4.1.2.4 Operation phase

During the operation phase the delivery of electricity takes places. In case there is no deviations from the planning, the whole grid stays in balance and everything will run smoothly. However, this is unlikely to be the case and deviations will occur due to changing weather conditions and the change in demand due to spontaneous events. Possible deviations will can affect market players in the following ways:

- The imbalance of a BRPs system
- Changes in the Aggregator's upfront agreed A-plan
- Local congestion in a DSO's grid

All players have also during the operation phase the possibility to purchase additional flexibility so the deviations can be balanced out.

The most important for the Aggregator is being able to follow his A-plan and D-prognosis. Until the operation starts he schedules his DR-assets in an optimal way. The schedules can be changed until operation starts. Continuous Measurement of the actual demand and supply in his portfolio, will allow the Aggregator to detect deviations to his planning. In the case of deviations, he can optimise his portfolio again. Therefore, he can either find a solution within the portfolio itself or changing the schedules for the devices.

The BRP wants to avoid imbalance costs which can arise from the TSO ancillary services or deviation from the BRP's E-program. To minimize those costs, he can buy additional flexibility from Aggregators.

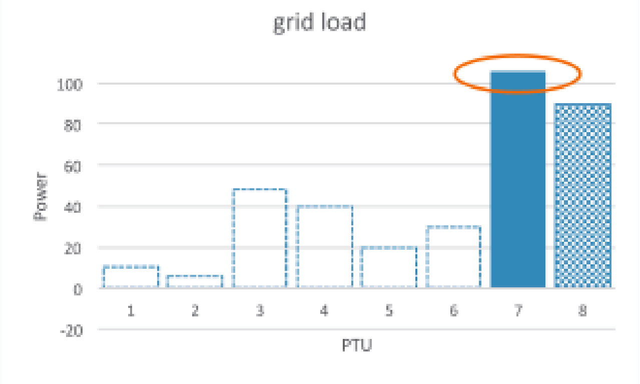
The same possibility exists for the DSO. He still can purchase more flexibility during the operation phase to avoid or resolve congestion issues. Since this will cause imbalance in the BRPs portfolio, it is likely that the Aggregator will add an imbalance risk fee to the flexibility price.

During the operation phase the grid load will continuously be watched by the DSO. In case there is not enough flexibility on the market, the system will switch to the orange regime.

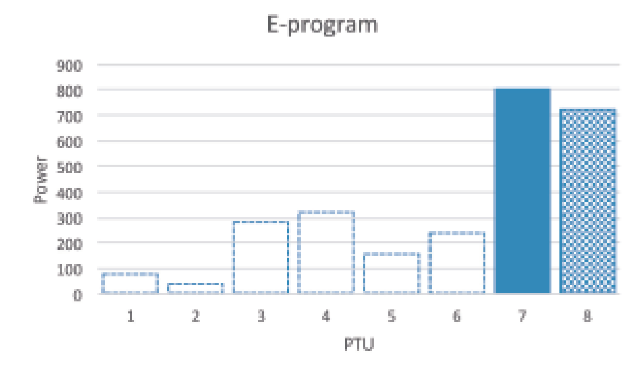
Simultaneously the TSO will watch the whole system balance as he is now and in case of any stability risks use the common ancillary services, second, primary and tertiary control reserves to avoid any outages. In addition, the TSO can also use the Aggregator's flexibility to restore system balance.

Use of UFLEX in the Operate phase

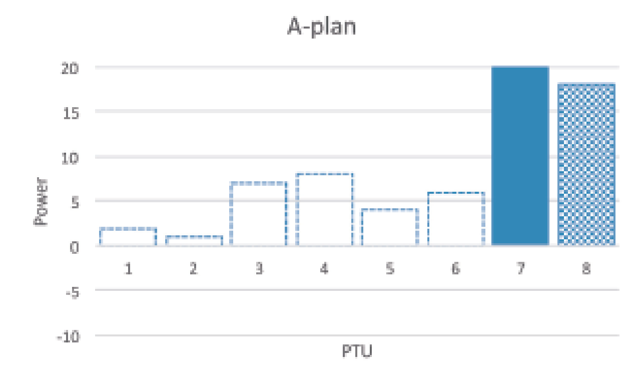
In this example, PTU=7 is in the Operate phase, while PTU=8 is still in the iterative loop over the Plan and Validate phases.



During the Operate phase, the DSO continuously monitors the status of the grid. If the actual load is higher than predicted, as is the case for PTU=7 in this example, additional or unpredicted congestion may occur. To resolve this congestion, the DSO can order UFLEX that was previously offered by Aggregators but has not yet been used. (Given the time limitations, it is too late to issue new FlexRequests for PTU=7.)
If the offered flexibility is not sufficient, the DSO will switch to the **Orange regime** and start stepwise limiting connections.



Likewise, the BRP will monitor its E-program. Deviations can arise from all sorts of sources, ranging from changing weather conditions to a football match running overtime. Any deviation will lead to imbalance in the BRP's profile, which it generally prefers to avoid due to penalties imposed by the TSO. The BRP might also deliberately deviate from its profile ("passive balancing"; see section 5.2) In all cases, the BRP can order UFLEX from Aggregators to help it maintain balance.



The Aggregator's task is to stick to its **A-plan** and **D-prognoses** per Congestion Point. Any deviations may require portfolio reoptimization, resulting in a new A-plan and D-prognoses and a new control strategy (set points) for the Active Demand & Supply assets. Portfolio reoptimization is also triggered by new UFLEX FlexOrders from BRPs and DSOs. The Aggregator's process in the Operate phase generally executes on the sub-PTU level, since deviations occurring in the current PTU (PTU=7, in this example) must be compensated for. Note that changes to the A-plan or D-prognoses may also create deviations in the next PTU (PTU=9 in this example), which will be resolved using the protocols of USEF's Plan and Validate phases.

Figure 24: In the operation phase of USEF the delivery of electricity takes place and imbalances are identified. Additional possibilities to purchase flexibility for all players (USEF, 2015).

4.1.2.5 Settlement phase

During the settlement phase BRP, DSO, Aggregator and supplier settle their energy and services provided during all the phases. BRP and DSO settle as well flexibility they have purchased from the Aggregator during the different phases. Aggregator and supplier do the same but the supplier may choose to include the flexibility settlement with the billing of energy delivered.

- **Settlement Aggregator-Prosumer**

  Being precise this transaction should not be a settlement. The reward or remuneration model for the Prosumer’s flexibility is up the Aggregator and not defined by USEF.

- **Settlement DSO-Aggregator**

  The settlement is based on the latest version of the validated D-prognoses.

- **Settlement BRP-Aggregator**

  In this phase, all the flexibility the BRP has purchased to optimize his portfolio is settled. Also the difference between the Aggregators forecast and realisation have to include since all changes to the initial schedule cause imbalances in the BRP’s portfolio.

- **Settlement DSO-Prosumer**
  Should the system switch to the orange regime the DSO has the possibility to cut load or generation on the level of the Prosumer. The reimbursement for his coercive measures are settled retrospectively between Prosumer and DSO. However, the settlement is not necessary to implement the USEF concept but recommended.

Figure 25: The settlement phase of USEF the trades between the individual parties are financially completed (USEF, 2015).

4.2 Three models defined by the Smart Grid Task Force

In January 2013, the Expert Group 3 of the European Smart Grid Task Force (EG3) published an annual Report that states three different models how data from smart metering should be handled and stored. The report was created by the Expert Group for Regulatory Recommendations. As described in the DOW it is part of WP 9.1 to comment on this paper and determine one of the models, which should be considered for the business cases in SEMIAH. In the following sections, there is a brief introduction into the three models so the work of the EG3 can be assed later. We can already pre-empt that the EG3 frameworks provided indeed valuable ideas. However, their suggestions focus only on the handling of smart grid data. The three EG 3 models do not give us much more guidance in what a future electricity markets could look like. This is one of the reasons why we have also introduced USEF as a point of orientation and a more holistic model.

4.2.1 Case 1: DSO as market facilitator

In the first model, the role of the market facilitator is assigned to the DSO(s). The DSO is operating a centralized or decentralized data hub in which he gathers all the operational and customer data for the market parties (see Figure 26). The data must be provided to all market participants in a non-discriminatory manner. Whether the data is enriched with additional information is a matter of the market players and it is up to them to create new services for the consumer. The owner of the personal data will always be the customer due to data privacy and security reasons. Therefore, the consumers would always have to approve when their information is transmitted to a third party. The responsibility of data metering is assigned to the DSO. Thus, complexity of the whole structure will be reduced.

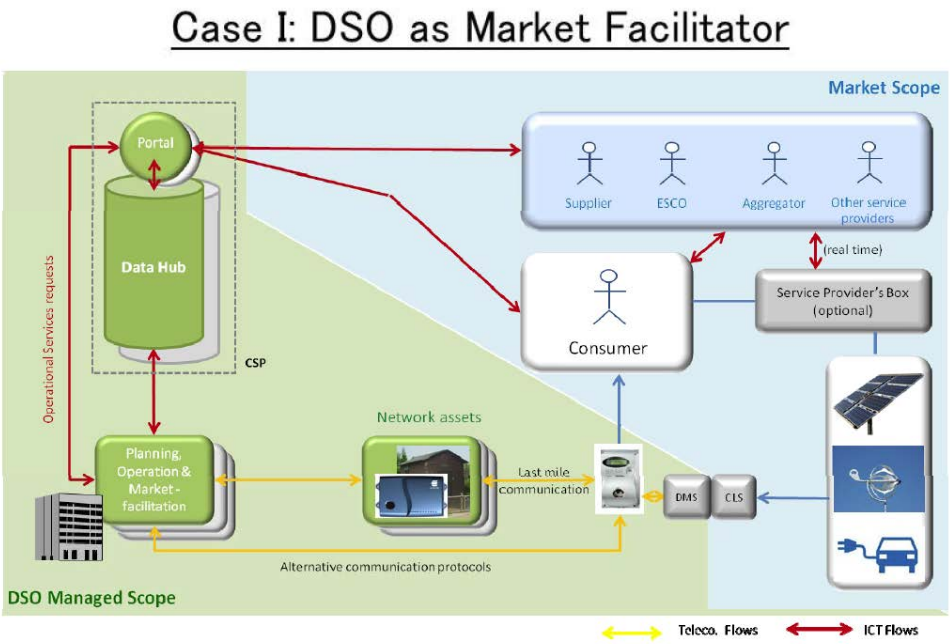


Figure 26: Model 1 – The DSO as a market facilitator (Smart Grid Taskforce, 2013).

Based on the paper the first model brings the following benefits and challenges:

Benefits

- High level of privacy, security and integrity
- The neutral role of the DSO(s) provides a encourages the development of new business models and competition
- The model guarantees transparency through its clear responsibilities. That characteristic keeps adjustment costs low and higher efficiency.
- Data produced by the DSO can be stored directly in their data hub. Therefore, additional transmission costs can be omitted and the approach is cost-effective.

Challenges

- Multiple data sources as the DSO only receives the Smart Metering data of his own customer. All kind of other information and from different DSOs are unknown to one specific DSO.
- All the Smart Metering task will be carried out by one single institution. This could result in a lack of investment to exploit the full potential of Smart Meter. That effect could be prevented by effective regulation.

This model for storing Smart Metering data is already implemented in the Netherlands. Belgium has decided to adopt such a system and in Portugal it is implemented for supplier Switching.

4.2.2 Case 2: Third party market facilitator

The approach described by the second model is based on a one independent platform that operates one or more data hubs (see Figure 27). It is a regulated agency with is subordinated to the government. The agency communicates with all stakeholders, stores the data and processes it. The platform ensures that only authorized parties receive and send data. One additional feature of the platform could be the responsibility of supplier Switching. Metering will not be one of the tasks the platform is performing. This will still be the job of organizations like DSOs and suppliers. The metering instance, whoever that might be, will send the metering data in a standardized format to facilitator. Especially in a market with many DSOs, suppliers and other service providers, this can be quite useful. One centralized institution gathers all the data measured and can then distribute the complete data set of a customer to an authorized stakeholder.

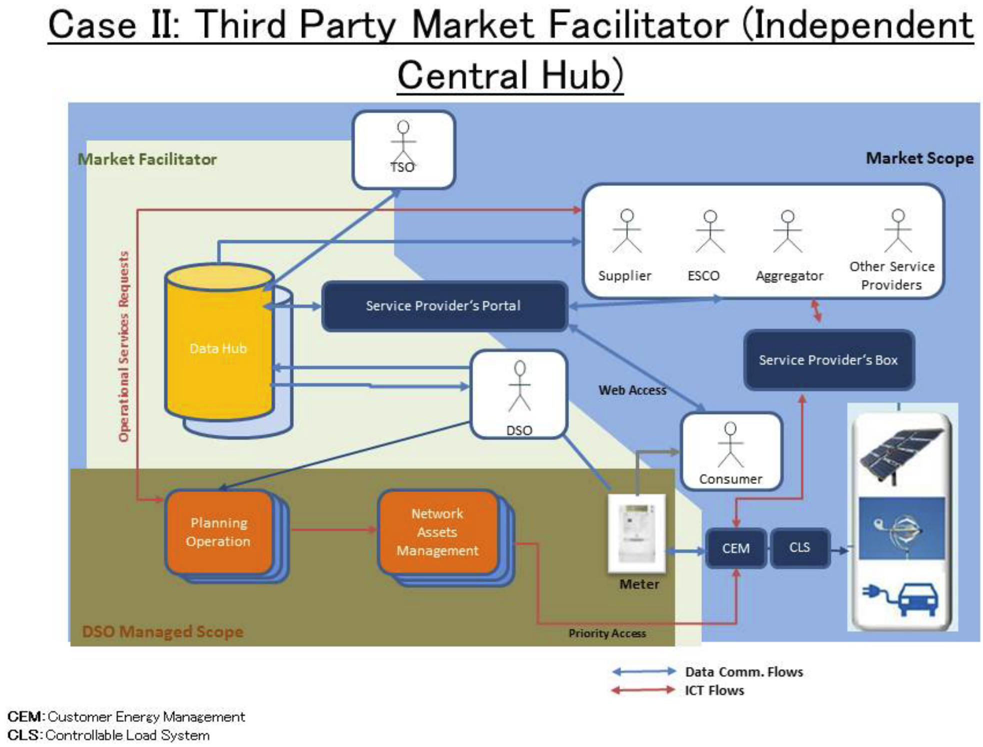


Figure 27: Model 2 – Third party as a market facilitator (Smart Grid Taskforce, 2013).

Based on the paper the first model brings the following benefits and challenges:

Benefit

- Independence and equal access for all players
- Economies of scales and effectiveness for smart grid deployment
- Regulatory control
- Facilitation of supplier Switching: only one platform stores the consumer information and can shift these data easily to the new supplier.
- A central data hub can result in cost savings for the deployment of a communication network and the data management

Challenges

- Regulation and a clear description of responsibilities is needed.

The following countries have implemented the second model: GB, Estonia, Denmark, Poland, Nordic Exchange Markets, Italy, Province of Ontario (Canada), State of Texas (USA), Ecuador and Australia. Ireland uses a de facto version of model two because only one single DSO oversees collecting and distributing smart metering data.

4.2.3 Data access-point manager

In the third model, a trusted and certified company takes over the role of a Data Access-Point Manager (DAM). These mangers will provide data access to any market player, consumers or prosumers that are legitimated to use certain data (see Figure 28). As opposed to the other two models the DAM does not collect or store any energy data. Thus, existing market structures would only have to be enhanced and not to be changed. In this model, any other party than the DAM can potentially metering the data. The data transmission privacy is ensured by advanced encryption methods.

By handling access to data and the remote control of required features, the DAM creates value added within the Smart Grid. The maintenance and application of access rights of any regulated and non-regulated market player is processed via an implemented communication network. As a result, new mechanisms for dealing with the information and features from a wide array of new and existing devices connected to the grid are required. Without the need to adjust the entire existing structures or system, the DAM must be able to connect, update, disconnect and localize those devices. Therefore, the DAM approach provides great flexibility to the handling of data while keeping the current market structure.

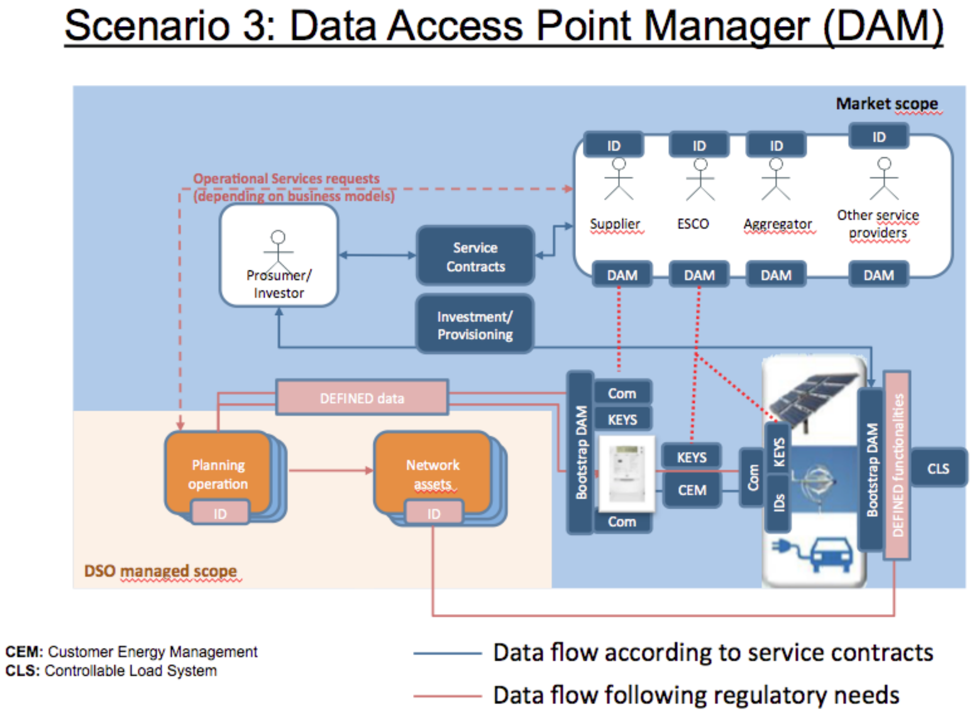


Figure 28: Model 3 – Data access point manager (Smart Grid Taskforce, 2013).

Based on the paper the third model brings the following benefits and challenges:

Benefits

- Fair, open and secure access to data and features of devices on the field level of different actors.
- Guarantees privacy and investment security based on its design.
- It facilitates the integration of devices and shortens the time to market span of new, innovative services and technologies.
- Consumer are free in deciding to participate in a demand-side program or investing resources in to retain energy costs low.
- Easing the Supply Switching processes.
- Privacy is an implicit part of the system designed. Except the owner of the data, nobody else than the owner of the data will be able to see the full range of data.

- Consumer have the possibility to decide what they want to show to which party.

Challenges

- The model needs a high level of standardization and certification rules.
- The energy market is national and local contrary to the internet. This means that the DAM needs to be integrated in existing regulatory environments that is in alliance with other local technical standardization.
- The successful introduction of the DAM model eventually depends on the new business models that are developed in the given framework.
- The DSO must trust the new DAM offering services. Additional control cost will arise and must be integrated in the operational expenses of the DSO.

Parts of the DAM model are implemented in Great Britain's Smart Energy Code Germany's BSI protection profile.

4.3 Business case layers

Once the flexibility of several thousand households can be accessed and aggregated, the question remains how can it be exploited on the market and create a real value added to all the parties involved. There needs to be realistic and economic feasible business scenarios otherwise the whole SEMIAH project will not be marketable. We need sophisticated business models that bring benefits to both sides: the end-consumer and the operator of SEMIAH. From current market trends and its own experience with DR, MIS together with the SEMIAH consortium has identified three different business layers: service layer, grid layer and a trading layer. The three business layers serve as a base for possible business cases and can be combined with each other. While it can be difficult to create a business case, based on only one business layer, it is also difficult to exploit flexibility on all three layers at the same time. The reason for that is the limitation of flexibility, the more flexibility is exploited one layer the less is available on the others. The layers reflect to some extent a trade-off.

Based on the business layers, the market scenarios and the simulation results in chapter 5, we will then define some specific business models. Those models should be profitable and possible to implement in today's power markets or the near future.

4.3.1 Service layer

Through the ability of shifting the prosumer's demand, many new services for the prosumer itself can be created. Those services can be offered by a SEMIAH operator e.g. an electricity supplier to its customers. Hence, the operator can profit from a higher customer loyalty and increase its competitiveness. Those kinds of services will be most efficient in a competitive market environment, which is given for liberalized electricity markets. Of course, it is not compelling to offer new DR services to the customers, but it is an advantage compared to other power utilities.

We divide between, two main types of services that can be offered to a supplier's customer. The first one is only suitable for prosumers and not for consumer only households. The second approach is based on remote control and monitoring and does not depend if the client can produce electricity.

4.3.1.1 Self-sufficiency

The first service prosumer can profit from DR is Self-sufficiency. This means that prosumer try to become as independent from the grid as possible. The simplest approach to do so is synchronising a prosumer's electricity demand and consumption. Hence, the prosumer needs some type of generation unit such as a rooftop solar. The devices can then be turned on when the sun is shining and turned off when it is too cloudy or night. Of course, this will not always be possible and the devices will also be on during times with no sun. In case, the prosumer has a battery he can than fulfil its demand with that, otherwise he must purchase electricity from the grid. Thanks to the harmonization of demand and supply, the maximal amount of produced energy can be consumed and thus the energy bill reduced.

Not only the amount of energy consumed drives the prosumers electricity bill (depending on the type of contract between supplier and prosumer), also capacity is often one component. The higher the maximum peak-load during a certain period, the higher the grid fees. Certain contracting models even depend on the number of peaks over a defined period. If consumption and production can be optimized to minimize the number of peaks or to reduce the maximum load, the power tariff will also turn out lower and the prosumer saves money.

In addition to the optimal solution for the individual, aggregated effects of load-shifting play an important role for DR. While it is optimal to shift consumption for one prosumer, it can be unfavourable on an aggregated level to a DSO or an energy supplier. In an extreme case, that means that by shaving one peak another one is created. In addition, it must be considered that avoiding grid costs for some consumers mean that the income for DSO will decrease. Depending on how significant those losses are, the DSO will increase the grid charges what makes the people not optimising their load profile worse off. Such a situation can become even worse. Then the higher the grid fees are, the higher is the incentive to avoid grid costs. The capacity cost must be increased again since even less people will be paying. Eventually the remaining end consumers will pay an overproportioned high share of the investment and maintenance costs of the grid.

4.3.1.2 Remote Control & Monitoring

Thanks to the equipment and technology in place, several other services can be provided by the DR technology owning company, without having high additional investment costs. The SEMIAH backend system continuously collects and stores anonymised consumption and production data as well as temperature data points of boilers. The data can be made available for the prosumer on his smartphone or computer via an app or another online interface. This can serve for his own interest and as a possibility to check whether everything is fine.

Besides monitoring, it is also possible for the prosumer to control certain devices remotely. As an example, one could think of a prosumer on vacation that would start his heating just before he comes home so the house has the desired temperature once the prosumer is back. Another possibility is to turn off the light once the prosumer left the house but forgot. In case the prosumer’s household is used for active DR, he can set comfort levels and blocking times for his devices convenient via his tablet or smartphone. Comfort settings ensure that DR will not have an impact on the prosumers well-being and do not disturb him.

Remote Control is not a service only the prosumer can profit from. Also, operator of the SEMIAH system can benefit from such the new opportunities. In case of a technical problem with one of the controlled units in the households, the operator can solve the problem remotely. Only if this is not possible, he can for instance switch off the device (to avoid any dangerous situation) and send an employee to fix the issue on-site. Service contracts are not needed anymore and maintenance costs can be minimized. Predictive maintenance even can lower investment costs and prevent failures entirely. Thus, the operator becomes more efficient and can avoid unnecessary expenses.

4.3.2 Grid layer

The aggregated flexibility of households can be used to smooth the grid load over time. This does not the decrease the energy consumed but lowers the need for capacity. The grid is utilised more efficiently and even new possibilities to stabilize the grid are provided. Flexibility is used to lower investment and operation costs. Those new opportunities address mostly DSOs. Depending on the market framework, also Aggregators could profit from the grid layer.

4.3.2.1 Optimal grid utilisation

The electricity grid is built for the peak hours. Even though the maximal grid capacity is reached only a few hours during the year, exactly those hours determine the investment need. Our grids must guarantee stability at any time. Hence, peak-load is one of the main drivers for grid investments. If we succeed in reducing peaks, DSOs will be able to save or to postpone grid investments. Mainly two possibilities exist to get rid of peaks: peak shaving and peak shifting. The initial one means that we can cut the peaks without having to consume in another period. Thus, we save energy. Such an approach mostly will succeed when process can be made more efficient and technology is more advanced so that devices consume less electricity. This is something we cannot influence by DR. Only if energy consuming processes turn out to be redundant, such as heating during certain periods, peak-shaving is relevant for SEMIAH.

More important for a DR technology is peak-shifting. This means that an energy consumption is shifted to a point in time when the grid is less utilised. The reduction of the highest peaks will lead to a smoothing of the load profile. Thanks to the smoother load profile, the grid will ideally be able to handle the same amount of energy using a lower capacity. Investments can be avoided or at least be postponed. Thanks to the time value of money concept, we know that even postponing investments already creates additional value for the DSO.

Another effect is that through the smoothing of the load profile, TSO grid charges can decrease. Most commonly they contain an energy and a capacity component. Since the grid fees are passed on to the end consumers, their costs will decrease. DSO become more efficient. Since they are highly regulated and are not allowed to maximise profits, increasing efficiency is one of their main objectives. DSO can also actively optimize their load profile against the TSO grid charges, which means minimising global peaks. Whether to minimize global peaks or to minimize local peaks is often a trade-off and can lead to contrary results.

4.3.2.2 Ancillary services on a distribution level

Until now the security of supply is mostly guaranteed on the transmission level and through penalties for BRP. We call it a top-down approach. In future market frameworks, as described in USEF, it is possible that the grid stability is based on a bottom-up approach. The flexibility of households and other plants and load devices are then used to balancing the distribution grid. If consumption meets production on a distribution level, it is also more likely to happen on a transmission level.

The DSO would have the possibilities to activate the flexibility from its customer or to purchase the flexibility from a third party. Which option will be chosen depends on the market framework and thus on the regulator. It is likely that the first mentioned approach would create market power issues and therefore the second option is more realistic. However, the principle will not change. Households will shift their consumption from a period of undersupply to a period of oversupply. In an ideal world, the grid always would be balanced and the ancillary services on the transmission level would become redundant or loose significance. The new approach would not replace current ancillary services. Moreover, it can be seen as a complementary service that increases security of supply and makes the integration of renewables into the grid possible.

4.3.3 Trading layer

The trading layer is more holistic than the other business layers. Flexibility is seen as a product that can be sold on different platforms for different purposes. An offer will be submitted on all those markets and sold to the highest bidding party. In other words, the flexibility will be sold to the bidder that values it the most. The main markets that will be addressed for the exploitation of flexibility are the Day-ahead, the Intraday and the Ancillary service market.

4.3.3.1 Wholesale markets

With wholesale markets, we mean automatized markets like power exchanges such as Nord Pool and EPEX. On those markets, pricing-mechanisms and bidding processes are transparent so that a connected system can use available data for forecasts, analysis and bidding. If a DR participant wants to sell energy, he will submit a negative bid. That means in case his bid will be activated, he must turn off certain load devices so that more electricity is available. This has the same effect as producing electricity.

OTC markets are not very suitable since bids are based on bilateral agreements. Those are agreed via long term contracts or phone calls. Thus, the system cannot incorporate the OTC opportunities into the optimization problem. The only way to consider them for DR response is manually by the trader. Before the trader submits a bid, he will compare the optimization results and therefore the suggestions from the system with his OTC opportunities. Another option could be that the trader types all his OTC offers into the system, so the optimization can consider them like any other bid.

4.3.3.2 Ancillary services

Currently ancillary services are offered by the TSO and help to balance the grid to eventually prevent black-outs or grid instability. The ancillary services on a DSO level as explained in the previous chapter do not exist yet. Thus, now a DR system on the trading layer would only consider the different ancillary service products on a TSO level. Those products are typically separated into three different levels: Primary control reserves, secondary control reserves and tertiary control reserves (compare Chapter 3.3). The classification and the offered services vary from country to country. If the regulatory framework in a country allows for the participation of prosumers on the ancillary services, usually tertiary control reserves is most suitable segment for DR. In some countries, even secondary control reserves could be considered for bidding by DR units. However, it should be said that the higher prioritized the product is on the ancillary service market the more difficult it is to participate for DR. The prequalification requirements increase a lot, the closer the ancillary services are at real-time. Hence, it may be only possible from a technical point of view that households contribute to the tertiary ancillary services market.

If a demand and response unit would like to participate in the ancillary service market the principle is the same as on the wholesale markets. To provide positive control reserves, load devices must be turned off and for negative control reserves the devices must be turned on. Generally, the negative control reserves are easier to provide for the demand side than positive ones. For negative power bands, devices just need to be turned on, what usually is less of a problem than turning them off when in use. This depends on the type of demand though.

4.3.3.3 Buyer union

Until now in most of Europe end-consumers do not profit from low electricity prices. In the last few years, prices have been sinking on the wholesale market. On the contrary end-user tariffs have stayed unchanged or even increased. To let end-consumers profit from decreasing wholesale market prices, so-called buyer unions could be formed. The unions could follow a non-profit approach so that households could nearly buy their electricity to the wholesale market price. Only a small surcharge would be added for the overhead cost to run such a buyer union.

Buyer unions only make sense in liberalized electricity markets where prosumers can choose their supplier. Buyer union would then be in direct competition with suppliers. Since buyer unions only focus on electricity trading and do not own any power plants or other heavy assets, they will be very flexible. Further they will try to keep their overhead as small as possible to minimize fix costs.

However, market coupled end consumer energy tariffs and a trend toward self-sufficient neighbourhoods may not allow for buyer unions. Energy suppliers all over Europe have started to offer tariffs that are based on the wholesale market price. Hence, end consumer can already profit from decreasing prices if the surcharge from the supplier is not too high. In addition, recently research projects have been started that have the idea of independent neighbourhoods (Smart Energi Hvaler, 2017). In the most distinctive form, they would become independent and neighbours even can trade directly electricity with each other. In such a future scenario, buyer unions do not make sense.

4.4 Market scenarios for active DR

Based on USEF and with prospects to the simulation, we have defined two different market frameworks that show potential use of the SEMIAH technology or a similar DR system for households. The two scenarios allow us to systematically assess the potential of the business layers explained in the previous section. While the first scenario is only assessed in D9.2 the second market scenario was partly examined in the Master Thesis by Funk & Wood (2017).

4.4.1 Scenario 1 - Current Market Model with SEMIAH technology

Scenario 1 is based on a market framework that reflects the current circumstances. The idea is that the SEMIAH technology could be implemented by an Aggregator as the circumstances are now in any of the member countries. Certainly, there are regulatory differences between the countries and the market model varies but the big picture stays the same. The Aggregator would use active DR to exploit the household flexibility. The objectives thereby are minimizing the power procurement costs, minimizing the balancing energy and maximise the profits from the ancillary service markets. To minimize the procurement costs, the Aggregator is exploiting Day-ahead and Intraday products. The three objectives can be contrary but always the most profitable option will be chosen by the optimization.

Figure 29: The Aggregator exploits the prosumer’s flexibility within a market framework as it is currently common in Europe.

The contractual situation between the prosumers and Aggregator is not defined. It can be that the Aggregator offers services to them such as remote control or consumption insights. It also possible that the Aggregator let the households profit from better the value generated by the flexibility. In the case that the Aggregator is the supplier at the same time, he could also provide the households better tariffs if they participate. Which option would be chosen depends to a lot on the value of flexibility generated and the competition within the market he is acting.

4.4.2 Scenario 2- USEF market model on DSO flexibility markets

Scenario 2 is based on the USEF market design described in Chapter 4.1. The market model is the same as in scenario 1 but an additional market for flexibility is established. The Aggregator can now trade flexibility with other third parties such as BRPs and DSOs too. At the same time flexibility is still exploited on power exchanges and the ancillary service markets. DSOs can purchase flexibility to balance their distribution grid and to optimise their investment costs by load shifting. Congestion is avoided whenever needed the security of supply increases. Balancing power is no longer only used to minimize the Aggregators own balance power, it can also be purchased by other BRPs to avoid balancing costs. The flexibility will be used for the party bidding the most and therefore where it is needed the most. Due to the higher number of potential buyers, the value of flexibility is supposed to rise. While the supply side for flexibility stays the same, the demand side increases. Thus, market model 2 is supposed to be more lucrative for a technology like the SEMIAH one.

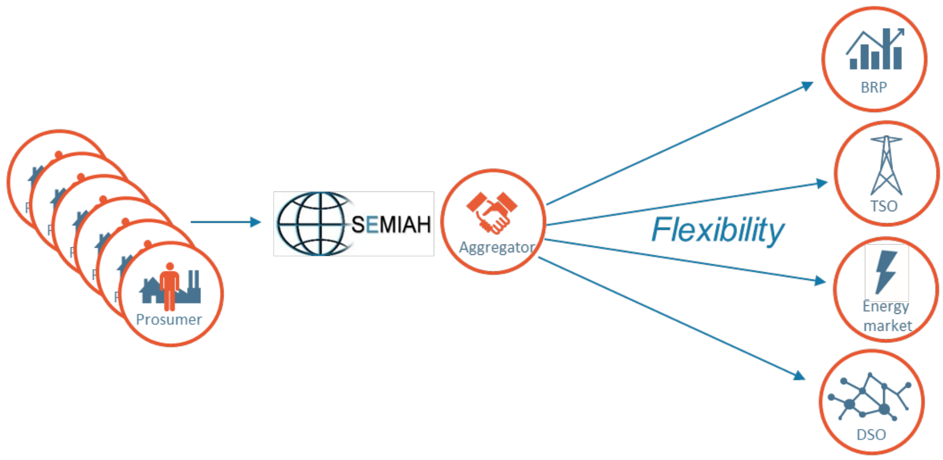


Figure 30: The Aggregator exploits the prosumer's flexibility on the traditional power market but also on an additional market for flexibility.

The contractual situation between the prosumers and the Aggregator is the same as in scenario one. There are several options on how the prosumers are motivated to participate in active DR depending on competition and the value of flexibility. It should be noted that at this point, we do not assign the role of the Aggregator to an existing or new entity. The role could be taken over by energy supplier or by new market players.

5 Simulation - The value of flexibility

The theoretical frameworks and business layers look good on paper. However, the economic feasibility is still questionable. In this chapter, we are now going to quantitatively estimate the value of the SEMIAH technology given the data from the SEMIAH pilots and other required market data. The simulation results are then used to assess the different business layers and market models defined in the previous chapter. From our findings, we are going present different specific business cases and assessment of their feasibility and marketability in the following chapter.

As mentioned above, a large extend of the market scenario 2 was evaluated in the Master Thesis of Funk & Wood (2017). The most important findings will be presented in the consecutive chapter. The details of methodology and further analysis will not be shared in D9.2.

5.1 Data

The following section describes the data that underlies the subsequent simulation. This includes household total load data, power exchange prices and tertiary control reserve prices, which is from now on referred to as reserve option market (ROM). The solar radiation data used to calculate the rooftop PV production is not included in this section.

5.2 Household data

The household data for boilers and residual load is taken from the pilots in Switzerland and Norway. Based on the configuration of the pilot and the quality of the recorded data, we were not able to use all connected houses. In Norway, there was hardly any households with heating installations included in the pilot (<4). In Switzerland, more houses with heating were included but the setup did not provide all the required data to do a simulation. For the houses with heating installations either only the global consumption was measured but not the boiler and heating consumption, or only the consumption of boiler and heating was measured but not the global consumption. Hence, we had to focus on hot-water boiler households since essential data for heating installations was not available.

To benefit most from the SEMIAH pilot data, we picked a period for our data which allowed us to maximise both, number of households and length of the time series available. Thus, we ended up with the period from the 14 Nov 2016 to the 9 Jan 2017. The same was already identified from Funk & Wood (2017). This gave us the possibility to use 22 houses in Norway and 14 houses in Switzerland. The simulation is based on the data sample period from the SEMIAH pilot, which serves as representative data. From that on, we extrapolated our findings to the whole year.

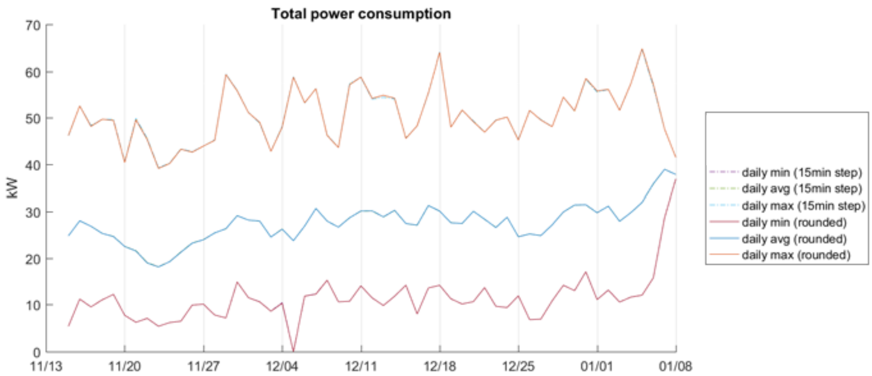


Figure 31: Aggregated power consumption of the 14 Swiss households. Please note that the lines which are not visible are behind the visible ones. Thus, there is not a large difference between rounded and 15 min time steps.

Figure 31 and Figure 32 show the aggregated total consumption of all the 36 considered households in Switzerland and in Norway. On average both aggregated consumption patterns are relatively stable with a slight upwards trend. In Switzerland, the aggregated average load during November, December and January fluctuates around 50 kW. The highest peak based on 15 steps was at 19:15 on January 7, 2017 and is 65 kW. The Norwegian total load is generally higher since it also aggregates more households. The peak for the aggregated load is at 18:30 on January 5, 2017 and equals 96 kW. It is interesting to note that both overall peaks were registered on the same day. Most likely, caused by low temperature.

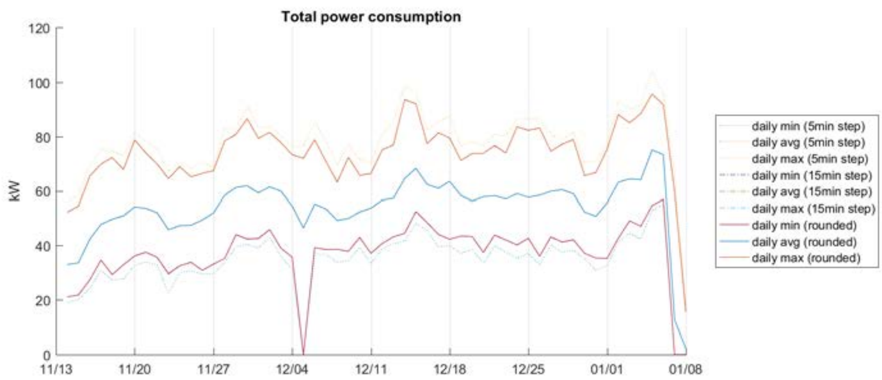


Figure 32: Aggregated power consumption of the 24 Norwegian households. Please note that the lines which are not visible are behind the visible ones. Thus, there is not a large difference between rounded and 15 min time steps.

We are not going to provide an analysis of the individual load and consumption patterns of the households and boilers here. More details and findings on that subject can be found in D7.2 and in from Funk & Wood (2017).

5.2.1 Power exchange prices

Over the last few years, we have seen decreasing electricity prices in most of Europe. From a local high in February 2012 of 55 EUR/MWh, German prices have gone down to 22 EUR/MWh in February 2016 (monthly average). However, towards the end of 2016 power prices climbed up and almost reached the yearly high of 2015 again (compare Figure 33). In the beginning of 2017 prices have had very high peaks but they have been decreasing ever since (EPEX, 2017). The future is uncertain. Additional capacity in the short term from renewable sources could increase the price pressure on the power exchange. In addition, we are likely to see further progress in efficiency. On the other hand, demand is likely to increase due to the continuous electrification (e.g. electric cars) and the supply side is shortened by the exit of nuclear energy and eventually also coal. Both would lead to increasing prices. Overall, we have two contradicting effects and it is difficult to say which one will gain the upper hand. However, in a long-term perspective it seems reasonable that prices will increase again.

Figure 33: German Day-ahead prices for 1 hour bids a monthly average basis from 2012 to 2016 (EPEX, 2017).

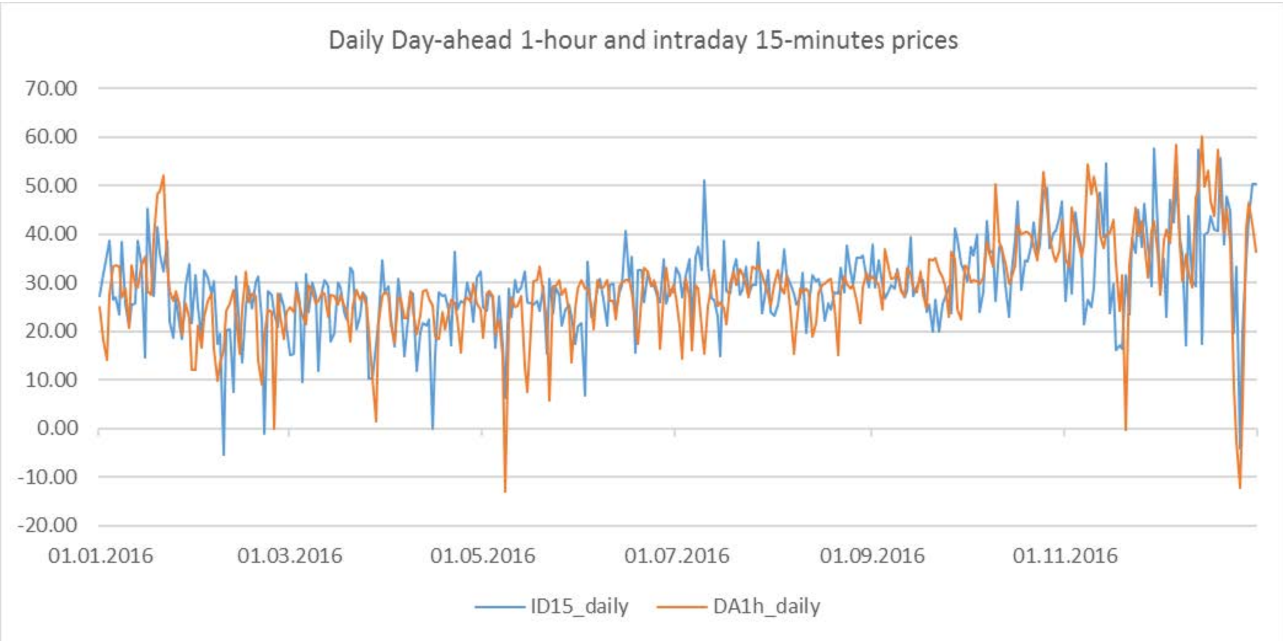


Figure 34: 1-hour Day-ahead prices and 15-minutes intraday prices in Germany from EPEX during 2016 used in the SEMIAH simulation (EPEX, 2017).

For the simulation, we considered the German day-ahead one-hour prices as well as the intraday 15-minute prices from EPEX in 2016 as shown in Figure 34. We decided to use the German prices since the intraday market is much more liquid and offers 15-minute products. The two prices are naturally moving together since they are based on the same product. They only differ in time of sale and delivery time. One would expect that the intraday prices would have a little premium for its closeness to the actual delivery time of power. Table 8, we can see that this is not the case. Mean and median are close and without any further statistical analysis, it is not possible to state any significant differences. Interesting is that volatility in form of the standard deviation is higher for the day-ahead prices (9.10 vs. 9.67). It does make sense that the shorter the time interval of a product is, the lower the price fluctuates from one time-step to another becomes. One should keep in mind that we are not only comparing a 15-minute product with one-hour product (difference in delivery time), we also compare an intraday product and day-ahead product (difference in time of sale). Thus, the difference in standard deviation also be linked in the longer time interval before the two points of decision. More uncertainty can lead to a greater variation in demand or supply prediction. Kurtosis and Skewness are both not very extreme so that we are dealing with slightly left-leaning distributions, which are relatively close to a normal distribution.

ID15_daily		*DA1h_daily*	
Mean	29.07	Mean	28.98
Standard error	0.48	Standard error	0.51
Median	28.55	Median	28.54
Modus	29.63	Modus	N/A
Standard deviation	9.10	Standard deviation	9.67
Sample variance	82.85	Sample Variance	93.43
Kurtosis	1.61	Kurtosis	2.56
Skewness	-0.04	Skewness	-0.20
Range	62.96	Range	72.95
Minimum	-5.37	Minimum	-12.89
Maximum	57.59	Maximum	60.06
Sum	10639	Sum	10578.65
Count	366	Count	365.00

Table 9: Descriptive statistics of the intraday and day-ahead prices in 2016.

5.2.2 Tertiary Reserve Control Power

In our simulation, we consider the Swiss ROM prices for positive and negative power bands. The ROM bids are handled as all the other ancillary service products by Swissgrid. While negative ROM is needed to balance the grid in a situation of excess supply (consume more power), positive ROM is required in a situation of a shortage of supply (feed in more power), as stated in Chapter 3.3. Naively, one would expect that positive reserve capacity is more expensive than negative because it is easier to consume more power than to produce more power. However, in 2016 this was not the case. Most of the time the negative control power bands were more expensive, what is good news for demand side participants.

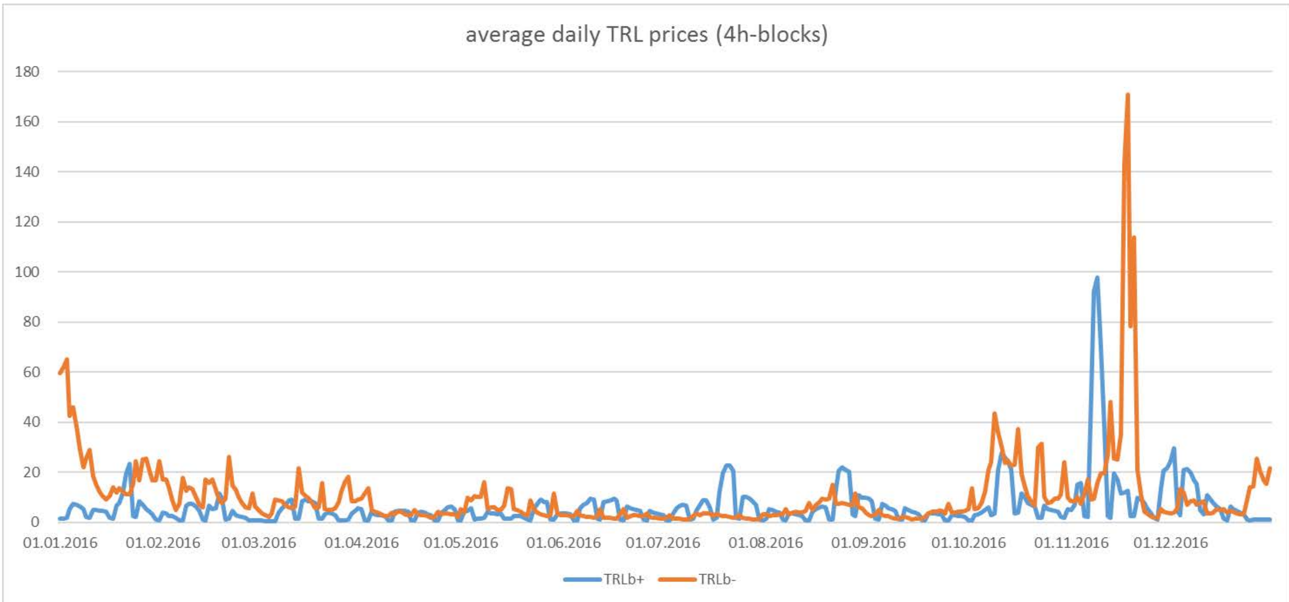


Figure 35: Daily average prices for ROM in Switzerland for positive and negative power bands in 2016 (Swissgrid, 2017).

The reason for the relatively high negative prices compared to the positive is that insufficient demand side units are available at the time of an activation call. Demand side units could often just consume more power without much effort. However, some demand side units cannot be just turned on. E.g. a cooling house might need to keep its temperature within a certain range due to the characteristics of some products. In that case, supply side units need to provide less energy. For supply side units, it is a necessity to have a high level of power production at the time the call comes in. Otherwise they are not able to cut the generation by the required amount and to lower the total load in the grid. Consequently, in cases of low negative demand side fallibility and difficulties for supply side units to cut power generation, negative ROM can become expensive.

Over all, the ROM prices in Switzerland are rather low. With a median of 3.94 CHF/MWh for positive and 5.47 CHF/MWh, it almost seems that it is only profitable to provide ROM when being activated. The power band provision itself is not enough. Over the year there were a few times, where ROM prices had high peaks, mostly during winter. From the kurtosis and skewness, we can see that the data is strongly concentrated around the median and highly left-leaning. The maximum of negative control power bands exceeds the maximum of positive ones by far (97.91 vs. 170.91). How much DR can benefit from ROM will be shown with the simulation (compare Table 9).

Positive ROM		*Negative ROM*	
Mean	6.26	Mean	10.29
Standard error	0.50	Standard error	0.83
Median	3.94	Median	5.47
Modus	N/A	Modus	N/A
Standard deviation	9.62	Standard deviation	15.89
Sample variance	92.57	Sample Variance	252.51
Kurtosis	45.33	Kurtosis	46.91
Skewness	5.80	Skewness	5.90
Range	97.58	Range	169.97
Minimum	0.33	Minimum	0.94
Maximum	97.91	Maximum	170.91
Sum	2290.69	Sum	3766.65
Count	366	Count	366

Table 10: Descriptive statistics of the positive and negative ROM products in 2016.

5.3 Key Performance Indicators

The performance of the optimisation is usually measured by a certain number of indicators, so called Key Performance Indicators (KPI). They are tools to verify the improvement of a scenario when running and comparing optimisations. In D9.1, we have identified all kind of possible KPIs in relation to DR and flexibility. Below you find the KPIs that were used to analyse the optimisation. Some of them are used in the text body of the document, other are shown in the Annex B where the results are listed.

Consumption

Total electrical consumption	Total consumption of electricity by all connected units.	MWh
Electrical consumption. appliances	Total consumption of electricity by all appliances.	MWh

Flexibility

Historical flexibility revenue	Revenue earned from flexibility in one year per installation	EUR/inst/a

Ancillary services revenue	Revenue earned from ancillary services in one year per installation.	EUR/inst/a

Economics

Balance energy costs	The amount of balance energy thanks to optimizing consumption and production within the pool.	EUR

Table 11: KPIs used in the analysis of the simulation.

5.4 Methodology

In this chapter, we explain the procedure of the market simulation for the SEMIAH technology. Firstly, we describe how the DR household were modelled and how virtual data was created to simulate many households. Secondly, it is explained how the data was aggregated and disaggregated so that it can be handled by the optimisation. To do so, the households will be divided into subgroups. Thirdly, the optimisation is discussed to show its different steps and assumptions.

5.4.1 Household model and virtual data

The basis of the whole simulation are households. The households can be normal consumers or prosumers that have installed SEMIAH technology. Hence, not every household will be equipped with the same devices and consequently not be able to provide the same amount of flexibility. The standard household consists of a controllable hot water boiler and non-controllable devices. The load is therefore divided into boiler load and residual load. For prosumers, households can additionally be equipped with a battery and a rooftop PV (compare Figure 36). Whether a household has a rooftop solar is determined randomly. In the case that a rooftop PV is assigned a battery might be assigned. If there is no PV installation, the house will also not have a battery.

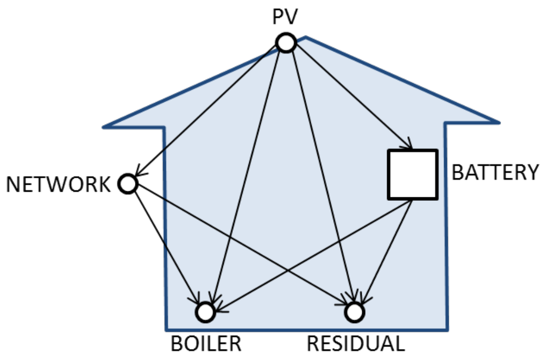


Figure 36:The prosumer household model which we used for the Simulation. The SEMIAH DR technology can control battery and boiler behaviour while rooftop PV and residual load are fixed. The house is connected to the network, which feeds the demand of the household not meet by rooftop solar.

5.4.1.1 Boiler and residual load

The boiler load data from each household is controllable and therefore will be optimised. Total energy consumed over one day is kept constant to guarantee that the energy inflow into the boiler does not differ over one day. Energy equality over one day and boiler load constraints will guarantee that the temperature does not drop under the comfort settings of the consumer. The approach is indirect and cannot refer to absolute temperature values. The boiler load constraints are determined by Misurio's developed sieve approach. A detailed description of the boiler load constraints can be found in Funk & Wood (2017).

From the SEMIAH pilot, we have data from 22 Norwegian and 14 Swiss households for boiler consumption and residual load. For the simulation, we need several thousand households. Consequently, we had to generate virtual data that is similar to the real data and allows us to simulate a large aggregation of those houses.

As a first step, we had to filter the residual load data. The filter dismissed outlier days, which was based on the following criteria:

- The data points of energy consumed per day must remain within boxplot whiskers I.e. they are defined as outliers, if they are greater than q3 + w × (q3 – q1) or less than q1 – w × (q3 – q1). The variables q1 and q3 are the 25th and 75th percentiles of the sample data, respectively. W is defined as the interquartile range.
- No more than 20% of the data points per day is not-a-number (NaN) or negative (residual load only).
- The energy consumed per day must be at least 1kWh

While the residual load situation for the Norwegian households during the observation period looks fine, two Swiss households do not have any valid days after the filter as can be seen in Figure 37. Hence, we had to dismiss two households when it comes to residual load and we remained with 34 (22 Norwegian households & 12 Swiss ones).

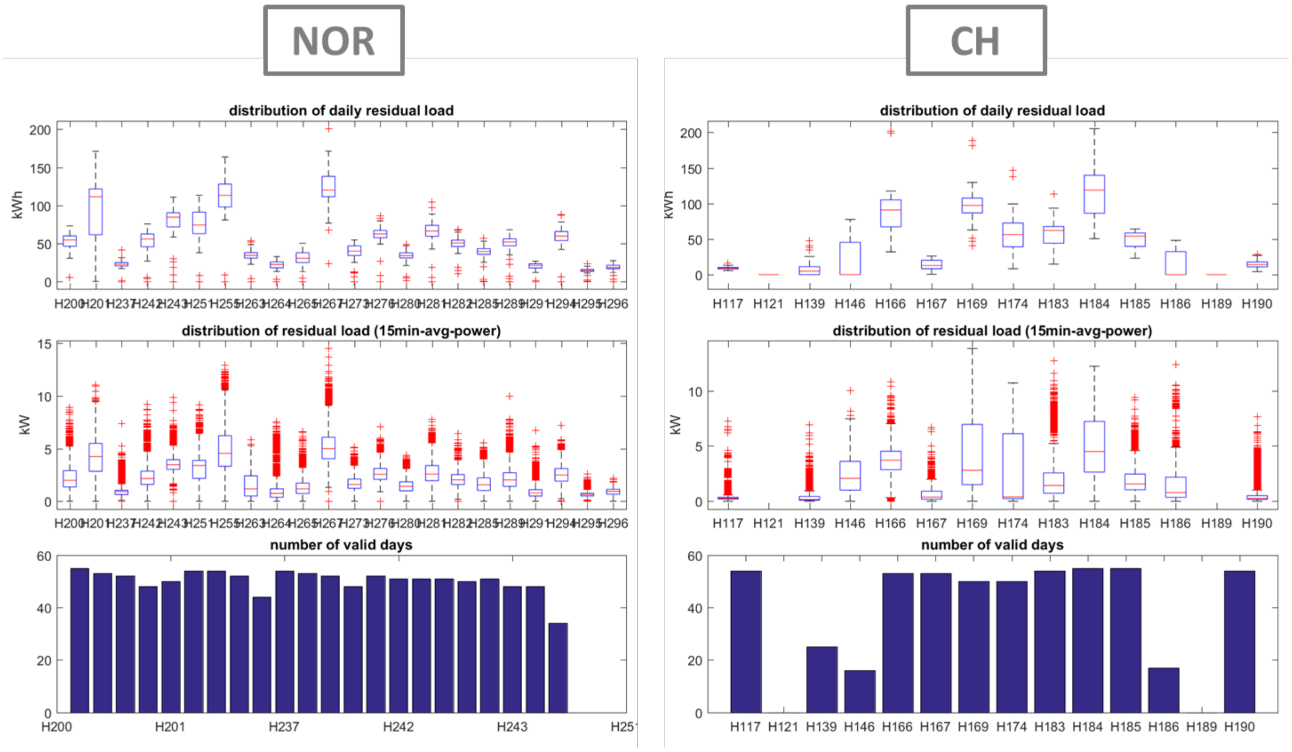


Figure 37: The boxplots for residual and boiler load for Norway and Switzerland respectively are shown above. The bottom two plots show the number of valid days out of the data sample for each household according to on the criteria described above.

For each household, we will then simulate two representative days for nine defined types of representative days (Weekday/Saturday/Sunday x Winter/Summer/Transfer). To create a virtual residual load curve for a new household, we pick one among the 34 available households and a random day. On each time step of the day, we apply an additional random factor between 80% - 120% which is independent identically distributed (i.i.d) over our sample period. In addition, we multiply the residual load by a scalability/seasonality factor, which corrects for the time of the year and weekday effects. The factor is based on the load data of the Engene transformer over the last few years and uses a certain day as a reference point. Every other day of the year is then adjusted based on the typical grid load in Engene (residential area in Norway). The process is repeated for each representative day, until we have the desired amount of household for the optimisation. Our new set of households will on average represent the typical SEMIAH household.

In a second step, we estimate the probabilities that a boiler switches on during at a certain time of the day depending on the time the boiler was off. Additionally, we also calculated the probable time, the boiler will stay on, again based on time-of-day and the amount of time the boiler was off. Figure 38 shows the different distributions and probabilities of when and for how long a boiler will switch on for the Norwegian household 200. There is a pattern that the boiler often switches on, shortly after just switching off around 8:00 and 19:00. At the same time, we can see as well, boilers mostly switch on after they have been off for 4 to 6 hours. This is most likely reflecting the natural re-heating interval without any human disturbance to keep the boiler at its set temperature. Thus, we receive switch-ON probabilities that are the highest around 8:00 and 19:00 after the boiler has been off between 4 to 6 hours. Nominal boiler power is determined based SEMIAH boilers from the pilot. As an appropriate value, we found 2.5 kW, which is applied to each household uniformly.

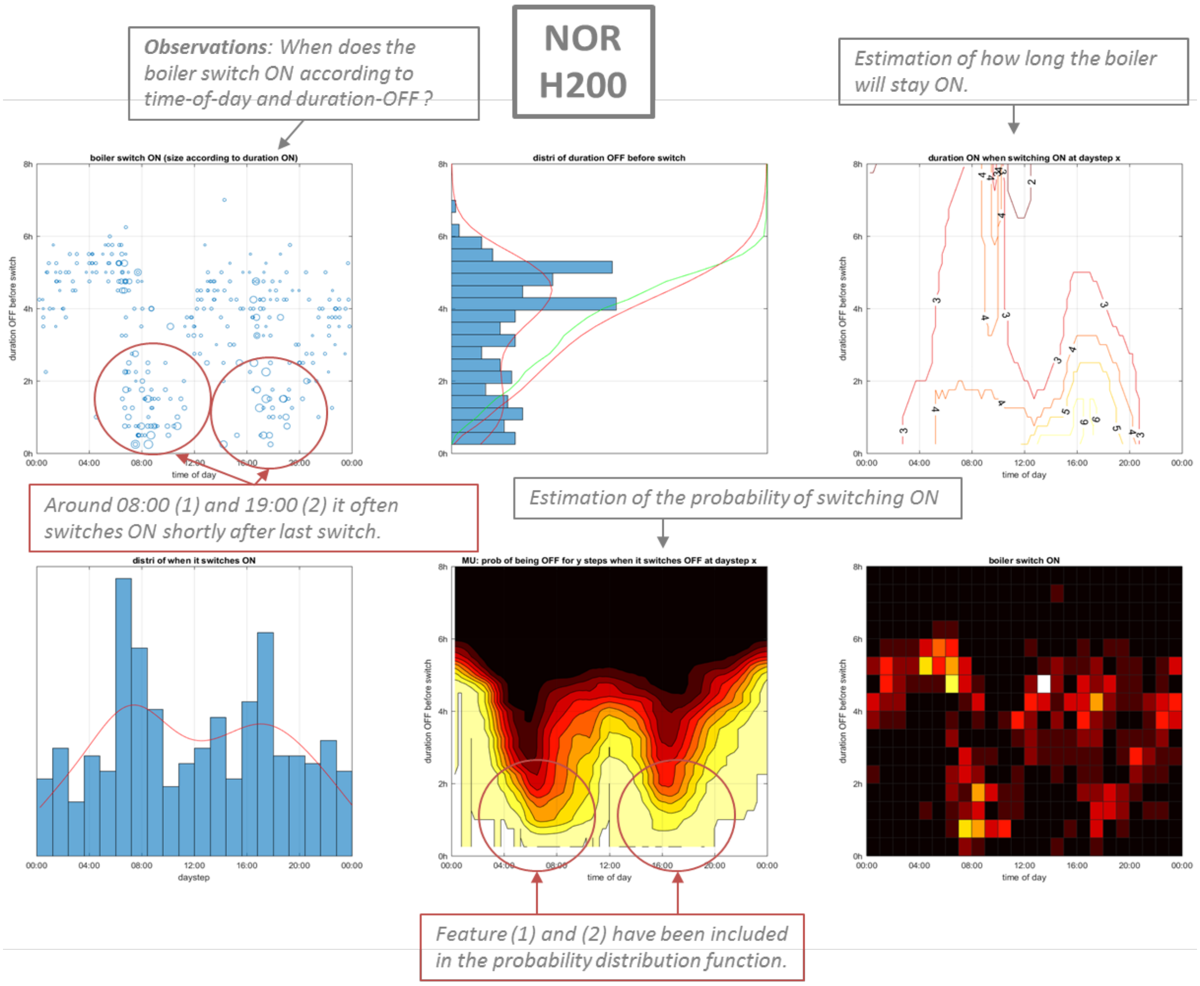


Figure 38: An assessment of boiler turning on and duration probability is shown in the Figure above. The top left graph shows a distribution of when the boiler switches on after it has been off. The size of the circle reflects the duration the boiler stayed on. We see a cumulation around 8:00 and 19:00 of switching on after only being off a short time. The top centre graph shows the distribution of the off-duration of the boiler. The green line reflects the integral of the blue bars (distribution function). The top right graph shows the number of time steps the boiler stays on when he has switched on after being off for some time. The left bottom graph shows the distribution of when boiler switches on. The bottom centre graph shows a heat map of the probability that boilers are off for a certain duration at a specific time, while black shows a probability of one and white reflects the probability of zero. The observations found in the first graph is nicely reflected in the heat map. The bottom right graph shows the same as the first graph (when do boilers switch on after being off for some time) with the difference that the graph is divided into a grid. Each square shows the density of the boilers switching on. The brighter the square the more the more time the boiler was switch on.

With all the estimated parameters, it is possible to generate virtual boiler and residual load data based on the SEMIAH households. To do so, we first pick one boiler among the 36 (22 Norway & 14 Switzerland) installations in our set of SEMIAH data and create virtual boiler load data based on its distribution function. As an example, serves Figure 39. It shows the boiler load observations compared to a virtually created set of boiler load data for the Norwegian household 200. The data is very similar in its characteristics but still gives us two different data sets for the optimisation.

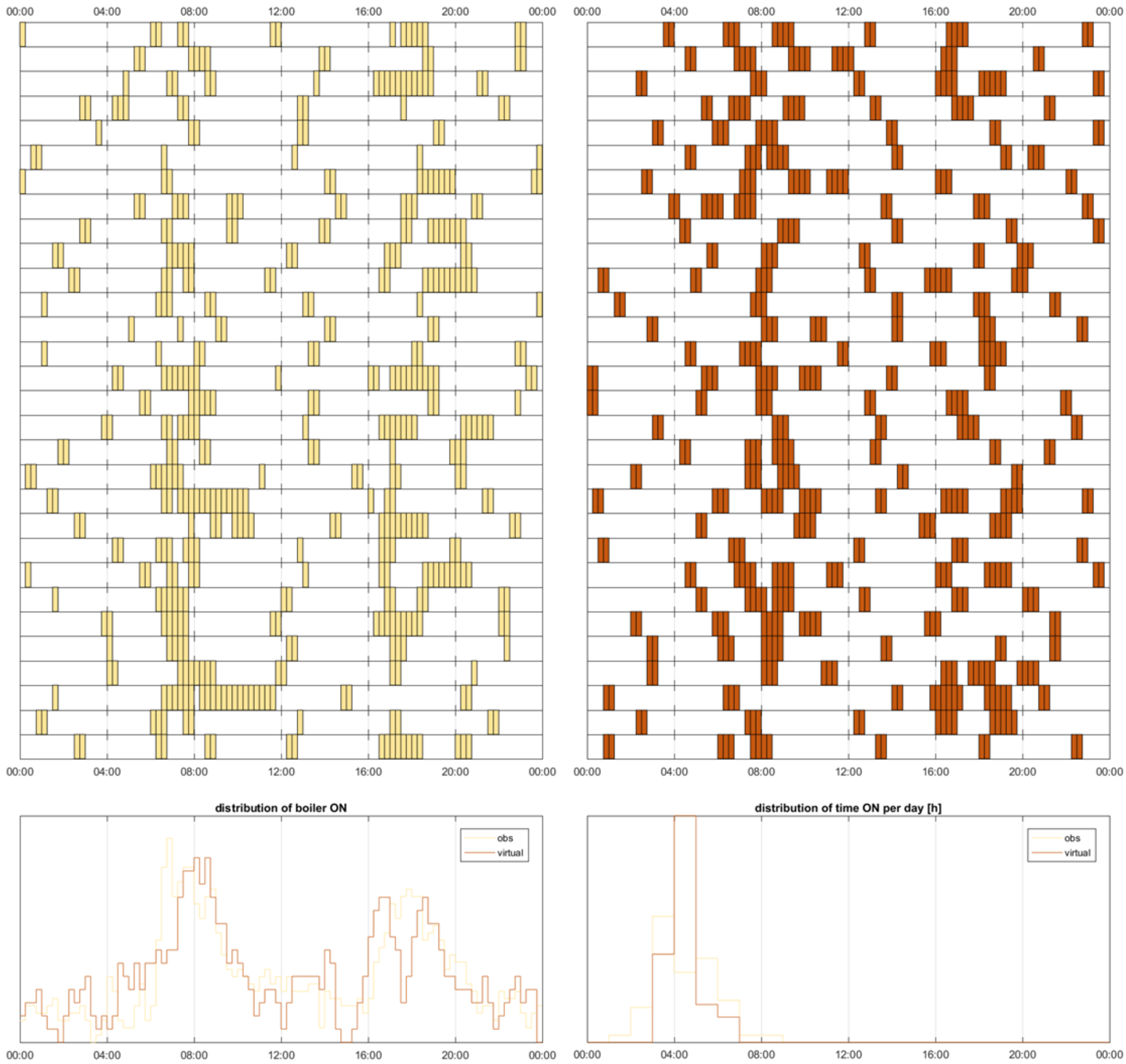


Figure 39: Comparison of the observed and virtual boiler load data for household number 200 is shown. The yellow plot above shows the boiler ON/OFF observations of household number 200 per day. The red plot shows the virtual boiler ON/OF data per day generated based on household 200. The two bottom graphs show the distribution for the boiler to switch ON and the duration-ON time for observations and virtual data

5.4.1.2 Rooftop PV

As stated above, rooftop PV is only an optional feature for the simulation household model. PV turns a normal consumer into a prosumer and offers him new possibilities when it comes to increase self-sufficiency. The household has the possibility to either consume the PV power directly or store it in its own battery. In addition, the power can also be feed into the grid to satisfy other households immediate demand. The model does not allow to use the PV produced power to fill someone else's battery. In the simulation model, a random uniformly distributed probability between 10% and 50% is assigned to a subgroup *i* of households. Based on this probability, for each household *j* of the group, it is determined if a PV installation is assigned. When a household gets assigned rooftop PV, its area A_j must then be estimated. This is done randomly by a normal distribution with a mean of

80 m^2 and a standard deviation of 40 m^2. The PV area is limited between 10 and 150 m^2. Eventually the PV production for each year was calculated for each household (assigned rooftop PV) by the following formula:

$$P_{i,j,t}^{PV} = \alpha_j \times \eta_j \times \left(f\left[(Gh_{i,t} - Dh_{i,t}), O_j, I_j\right] + Dh_{i,t}\right) \times A_j$$

The production of electricity from rooftop PV depends to a large extend on the solar radiation at a specific location. To account for a difference in solar production, we defined a list of seven different locations in Germany where solar radiation is measured (Deutscher Wetterdienst, 2016).[9] For each group of households one location is randomly picked so that real measurement values for solar irradiance can be used. Solar cells produce electricity using the visible light. Ultraviolet and infrared wavelengths are unused. Thus, direct solar irradiance considered for PV production is direct global irradiance Gh_j minus diffused irradiance Dh_j. The function f converts the direct irradiance on a horizontal plane surface into an inclined and directed plane with installation specific inclination I_j and azimuth angle O_j.[10] After adding again the diffused irradiance $Dh_{i,t}$ to the inclined, directed variance, radiation is multiplied by the installation specific efficiency η_i, perturbance α_i and the area of the solar panel.[11]

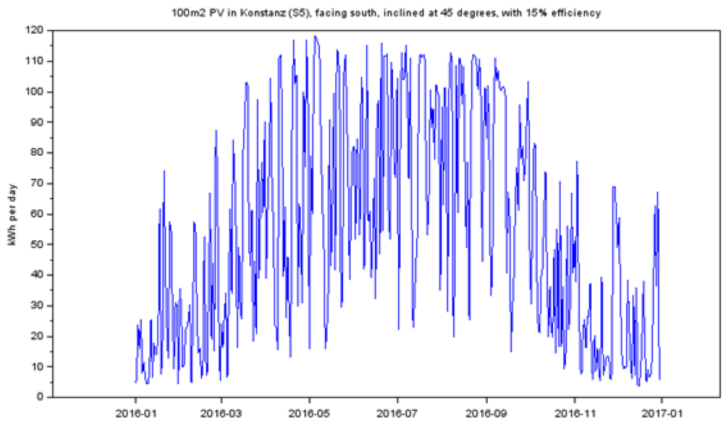


Figure 40: Yearly production of one household with 100m[2] of rooftop PV in Konstanz (Germany), facing south, inclined at 45° with an efficiency of 15%.

An example of the virtually generated PV production is Figure 40. The PV installation produced approximately 25 MWh during 2016 with 15 KWp. Since the produced power is based on real radiation data from 2016, we can observe a clear seasonal pattern which peaks in the summer and has its low during the winter.

5.4.1.3 Batteries

In addition to PVs the simulation houses can also have a Battery. They can only be assigned to households that have a PV installation. The probability for each household to have a battery is determined per subgroup (same subgroups as mentioned for PV) and is distributed uniformly between 0% and 50%. The capacity (kWh) is the product of the two parameters z_j and $A_j/10$. z_j is

---

[9] North-West-Norderney, South-West-Trier-Petrisberg, East-Görlitz, Center-Braunschweig, South-Konstanz, North-East-Rostock-Warnemünde, South-East-Nürnberg

[10] Solar panel orientation (azimuth angle (North = 0, East = 90° etc.)): installation specific normal random distributed parameter in [90 °, 270 °] with a mean at South = 180° and a standard deviation at 30°.
Solar panel inclination: installation specific parameter, which is fix for the whole year (no moving panel), uniform random in [20°,80°].

[11] Perturbance α_i is a i.i.d. factor that is uniformly distributed between 80% and 120%. Efficiency η_i is an instalation specific parameter uniform random between 10% and 20%.

a uniform random parameter between 0.8 and 1.2, while $A_j/10$ reflects a tenth of the households PV installation area. Through its specification, the capacity approximates the peak production of the PV installation. The battery power is retrieved indirectly, assuming that battery capacity divided by the battery power gives us a uniformly random distributed discharge time between 2 and 4 hours.[12] The efficiency of the battery is also uniformly distributed between 80% and 90%. The value is based on experiences from MIS reference projects. We define that the batteries are only used for PV power storage. Import and export of grid power is excluded so that there is no room for speculation. Batteries can be used for reserve control markets though. Losses are not taken into consideration.

5.4.2 Aggregation and disaggregation

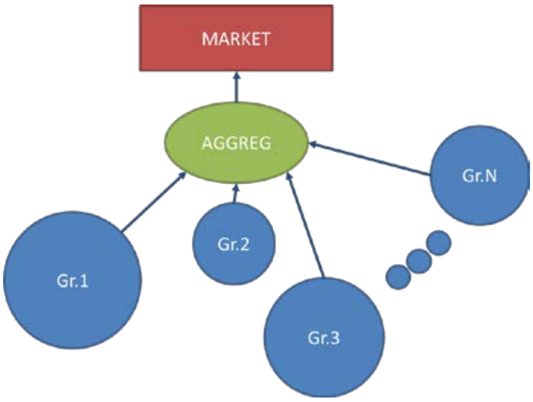
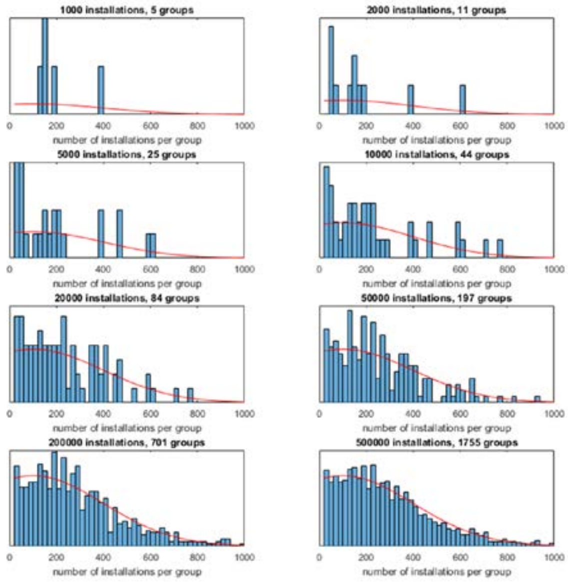


Figure 41: Scheme for the Aggregator's optimisation of the different subgroups against flexibility markets.

The optimisation of all the SEMIAH simulation is based on a very large number of households (up to 500'000). An optimisation of each individual house directly at the market, would take too long and is not feasible. Consequently, another approach is needed that simplifies the whole process and allows a realistic aggregation and disaggregation of the houses. Hence, we aggregated the households to subgroups, which are considered as the elements that are optimised by the Aggregator. After the optimisation, the results will then be disaggregated again so that each individual household receives a schedule that it must follow without insulting the comfort settings.



[12] This estimation of the battery power is based on real-world parctical values from Winsun AG in Switzerland.

Figure 42: Distribution of the group sizes for the different optimisation sample sizes.

Each subgroup is defined by parameters and consists between 20 and 1’000 households. PV, boiler residual load and battery of each house are summed up into one single, large element. In addition, to the aggregation of the individual load profiles, an additional residual load component is added. This component includes industry, households and service industry. Figure 43 shows the controllable households consisting of PV, boiler, battery and residual load and the uncontrollable residual load. For the optimisation, we set an overall peak for the whole group which is based on the virtual peak. The optimised load of each group is not allowed to exceed the virtual peak. With this constraint, we prevent additional newly created peaks. The size of each subgroup is following a standard distribution with a mean at 100 and a standard deviation of 300 while the values are limited between 20 and 1000. For each optimisation size sample, the distribution is redone (compare Figure 42).

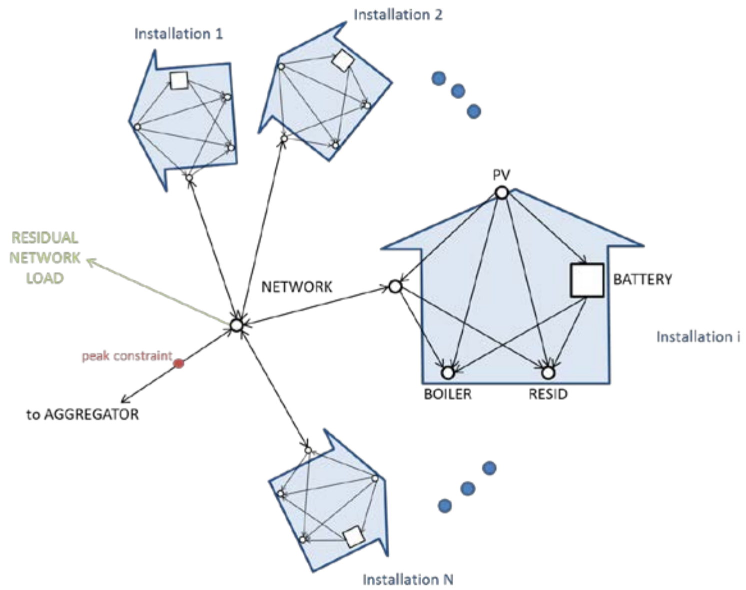


Figure 43: The aggregation of households and additional residual load to a subgroup is the key to an efficient optimisation. Each subgroup consists between 20 and 1000 individual household that are aggregated to one large element. In addition, a residual load element is added to each group that reflects uncontrollable households, industry and service industry.

To aggregate battery power, we cannot just aggregate the individual nominal power like for PV, since some batteries might be full and some are empty. The actual battery power typically depends on the actual State of Charge (SoC). Batteries charges slower when SoC is rather high or discharger slower when it is rather low. Thus, the battery power in our model is lower when they have a SoC smaller than 20% or larger than 80%.

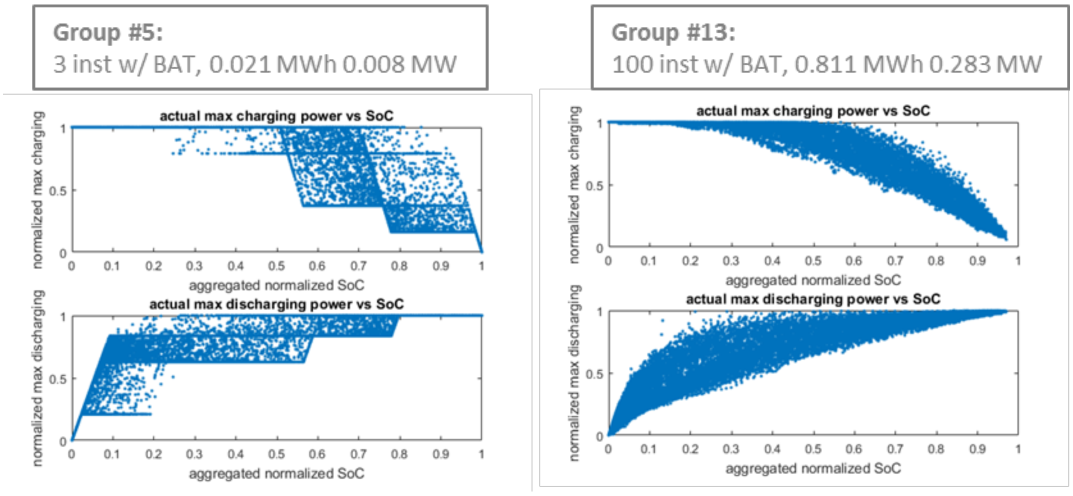


Figure 44: Battery charging and discharging times depend on SoC. Charging batteries takes longer with a high SoC. Discharging takes longer as well when the SoC is low. This relation is shown in the graphs above.

As stated above, solar power can be used to fulfil the immediate demand of other households. This is only possible for houses that are in the same group though. Consequently, the battery for certain groups is only useful (except for ROM) if the groups residual demand is smaller than the solar power produced by the same group. If this is not the case, all the solar energy is utilised to feed the group-internal electricity demand. In the 500’000-household simulation, 37% of the solar energy is consumed by the households directly and therefore their batteries are useless except for ROM.

As a next step, we know model the groups residual demand, reflecting the demand side not used for the SEMIAH technology. The proportion between controllable households and residual load is normally distributed with a mean of 15% and a sigma at 10%. The shares between households, industry and service industry is determined by the following procedure:

1. Randomly decide if the residual load of the group is only households with a probability of 50%. If yes, we can apply the standard load pattern for households see below.
2. If no, decide about the share of households using a normal distribution centred at 0.5 and with a sigma of 0.5/3.
3. The rest is split randomly (uniform distribution) between industry and service industry.

Once the shares of the three sectors are retrieved, we apply standard load profiles for the three sectors from Stadtwerke Unna (2017). On top of the standard profile, we applied seasonal and weekday patterns from internal Projects at MIS. The outcome is visible in Figure 45 to Figure 47.

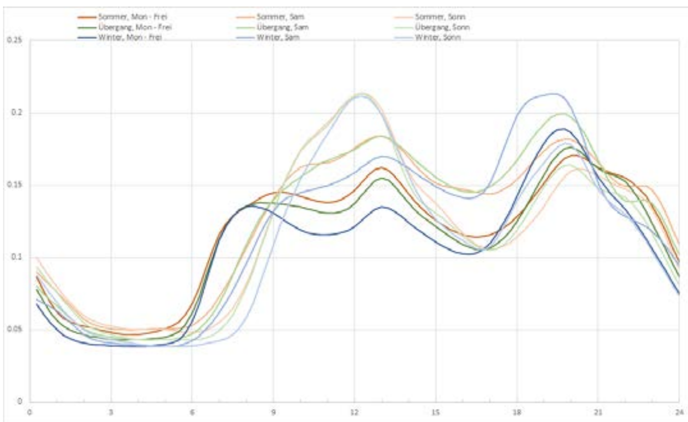


Figure 45: Standard load profiles for households from Stadtwerke Unna (2017) depending on season and weekday patterns based on other Misurio projects.

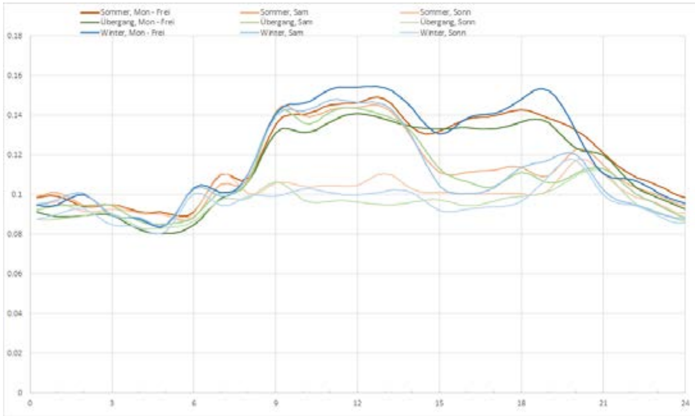


Figure 46: Load profiles for industry from Stadtwerke Unna (2017) depending on season and weekday patterns based on other Misurio projects.

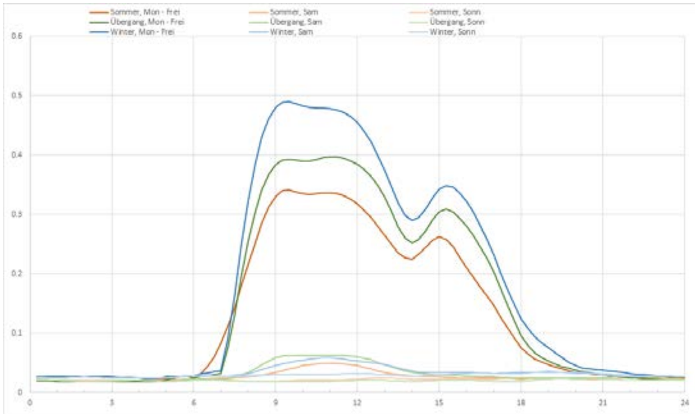


Figure 47: Load profiles for service industry from Stadtwerke Unna (2017) depending on season and weekday patterns based on other Misurio projects.

From the derived load patterns, we see that we divided the load patterns into a summer, a transformation and a winter period, as well as into weekdays, Saturdays and Sundays. This gives us nine different load type for each industry. The household profiles typically have two peaks over one day, one in the morning and one in the evening. On Saturdays, the load profile even has three local peaks which can be explained by some people still getting up for work early, while a large share of the population has the possibility to sleep in. Please note that the load profiles are in relative and not in absolute measures. Hence, consumption during winter months does not have lower peaks, even though on the Figures above it looks like.

The industry sector has a relatively flat pattern, that reaches its maximum between 9:00 and 19:00. The reason for the flat pattern is that we assume a continuous production. On Sundays, the pattern is almost flat for the whole day. There is hardly any seasonal effects. This could of course change if one would compare different industries. For simplicity reasons, we will not do that here.

The service industry sector only has consumption during working hours, defined from 8:00 to 18:00 during weekdays. During the weekends, consumption is almost zero.

5.4.3 Optimisation

As already explained in the previous section, the optimisation will exploit the flexibility of boilers, PVs and batteries on a group level at different markets. In this work, we will consider Day-ahead markets, intraday markets and ROM (4-hour blocks positive and negative). We will also show an example on how power balancing could be optimised. Grid fees and taxes and not directly modelled since they mainly are based on capacity (peaks). There is often an energy component but since we are only shifting load and defining consumption fixed over a day, the SEMIAH technology will not be able to optimise those costs.

Based on the available data and parameters, we figured that the best feasible approach will be a multi-stage optimisation. Therefore, the day-ahead and intraday prices were lined up in a single 15-minute step time-series. They will be assessed by three different price scenarios and three different price variances (spread scenarios) scenarios. In combination with the different levels of household aggregation (1000, 2000, 5000, 10'000, 20'000, 50'000, 200'000 and 500'000 households), we would end up with 72 optimisations (3 price levels x 3 price spreads x 8 aggregation levels), Due to the fact that the 500'000-household simulation is very time-consuming, we only asses the three mid-spread price scenarios. Thus, we have 66 scenarios and some additional ones to assess further characteristics of DR markets. Even though, it was initially defined to do only 27 simulations, we have decided to include additional aggregation levels. The reason for including more levels than planned are scaling effects. While in the lower range of aggregation (1'000 – 50'000) more positive effects from aggregating result (results improve faster than the increasing number of households), in the upper aggregation levels, scaling effects become more linear. This will be visible when we come to the result part. Once we have all outcomes, we can compare the two different market frameworks developed in Chapter 4.6 to the ones from the Smart Grid Task Force, EG3 First Year Report.

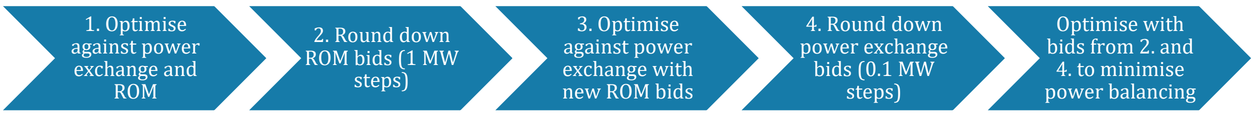


Figure 48: The multi-stage optimisation procedure for the SEMIAH simulation.

To include the effects of all different markets, we first start with an Aggregator optimisation against the power exchange and the tertiary reserve option market. Secondly, we round down the ROM capacity to 1 MW steps. The minimum threshold is 5 MW based on the Swiss ancillary market conditions. In case that the 5 MW is not reached, the Aggregator will not offer any ROM at all. Thirdly, we rerun the optimisation with the new ROM offers so that the power exchange prices are optimised again. Fourthly, we round down power exchange bids to 0.1 MW to assure feasible results. Lastly, we rerun the optimisation again with the ROM bids from step two and the power exchange bids from step four to minimise the power balancing (compare Figure 48). The aggregated results will then be used for further analysis. In the real world, the optimisation results are disaggregated again and send as schedules to the individual households and executed if feasible and not-conflicting with the comfort settings. In the SEMIAH simulation, we will demonstrate that on an example but not do it for all the households, since it will not allow us to gives us any further insights into the results.

The optimisation will first be executed over for 18 selected days, 2 days for each of the nine representative days (Weekday/Saturday/Sunday x Winter/Summer/Transfer).[13] The days have been selected so that we have all kind of typical load patterns in the simulated data reflected. From the selected days, the results are extrapolated to one year based on season and weekday typical load pattern factors. For one specific, selected group, the optimisation is run for the whole year.

5.4.3.1 Price sensitivity

To assess the price sensitivity of our results, we are going to run three different price and variance (spread) scenarios for our optimisation. The power exchange prices are lined up in one single time series in a 15-minute interval. The three price scenarios are simple and include a low, normal and high price scenario. In other words, the prices are multiplied by a factor α of 50%, 100% and 200%.

[13] The possible combinations for representative days are weekday summer, weekday summer, sat summer, sat summer, sun summer, sun summer, weekday trans, weekday trans, sat trans, sat trans, sun trans, trans, weekday winter, weekday winter, sat winter, sat winter, sun winter, sun winter.

$$P_t^{new} = P_t \times \alpha$$

The price spread is slightly more complicated. Based on the price scenario prices, we extracted the variance of the 15-minute prices and added them to the 1 hour day-ahead prices. If we did not restrict ourselves to the inter-hour variance, we would create arbitrage possibilities. The different spread scenarios include the same factor α as before but now applied on the spread instead on the price directly.

$$P_{h,d}^{new} = P_d^{avg} \times \alpha \times \left(P_{h,d} - P_d^{avg}\right)$$

The results can be seen in Figure 49 for the first ten time steps of our price time series. From the descriptive statistics, we can see that the average for one price scenario stays the same but the variance differs. Holding the price spread constant, the mean and variance double from the first to the second scenario, as well from the second to the third.

start	P11	P12	P13	P21	P22	P23	P31	P32	P33
-	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh
2016-01-01 00:00:00	11.43	10.38	8.29	22.85	20.76	16.57	45.71	41.52	33.14
2016-01-01 00:15:00	11.86	11.26	10.04	23.73	22.51	20.07	47.46	45.02	40.14
2016-01-01 00:30:00	12.71	12.95	13.43	25.42	25.90	26.85	50.85	51.80	53.70
2016-01-01 00:45:00	12.80	13.13	13.78	25.60	26.25	27.55	51.20	52.50	55.10
2016-01-01 01:00:00	13.94	15.41	18.35	27.88	30.82	36.69	55.77	61.64	73.38
2016-01-01 01:15:00	11.05	9.62	6.77	22.09	19.24	13.53	44.19	38.48	27.06
2016-01-01 01:30:00	11.60	10.73	9.00	23.21	21.47	17.99	46.42	42.94	35.98
2016-01-01 01:45:00	10.75	9.02	5.57	21.49	18.04	11.13	42.99	36.08	22.26
2016-01-01 02:00:00	12.91	13.35	14.23	25.82	26.70	28.45	51.65	53.40	56.90
2016-01-01 02:15:00	13.35	14.23	16.00	26.71	28.47	31.99	53.42	56.94	63.98

from 2016-01-01 00:00:00 to 2016-12-31 23:45:00

	P11	**P12**	**P13**	**P21**	**P22**	**P23**	**P31**	**P32**	**P33**
	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh
min	-53.58	-100.72	-194.99	-107.17	-201.44	-389.99	-214.33	-402.88	-779.98
max	42.34	58.35	96.80	84.68	116.70	193.59	169.37	233.40	387.19
avg	**14.49**	**14.49**	**14.49**	**28.98**	**28.98**	**28.98**	**57.95**	**57.95**	**57.95**
median	14.27	14.23	14.06	28.53	28.46	28.11	57.06	56.92	56.23
valid	100%	100%	100%	100%	100%	100%	100%	100%	100%

Figure 49: The nine different combinations of price and spread scenarios including the descriptive statistics.

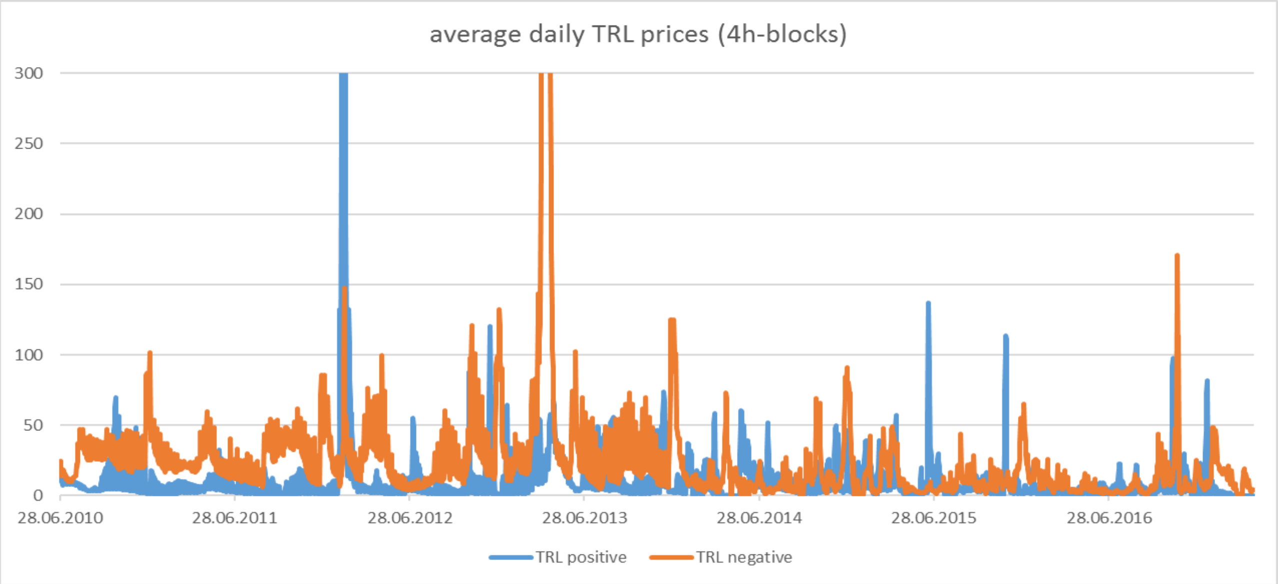


Figure 50: Daily average of ROM 4h-blocks for negative and positive control power from 2010 until 2017. The prices have been decreasing slowly. The two highest peaks are not shown entirely (Swissgrid, 2017).

For ROM prices, we decided not to apply the scenarios as initially planned. The reason for that is simple. The tertiary reserve option market is slowly dying out. Prices of ROM in Switzerland have been decreasing since 2010 (compare Figure 50). The instant power balancing is more and more taken over by the role of the intraday markets. Gate-closure times are coming close to real-time what gives power consumers smaller forecasts errors. Within Germany the closure times will decrease from 30 minutes to 5 minutes in Q2 2017. Hence, much more precise orders can be done since weather and market conditions for the next five minutes are relatively predictable. Thanks to this and the continues launch of new products, the volume on the intraday market is continuously increasing since its start in 2010 (EPEX, 2017). In addition, the number of participants at ROM has been increased during the last few years, what puts more pressure on the market prices.

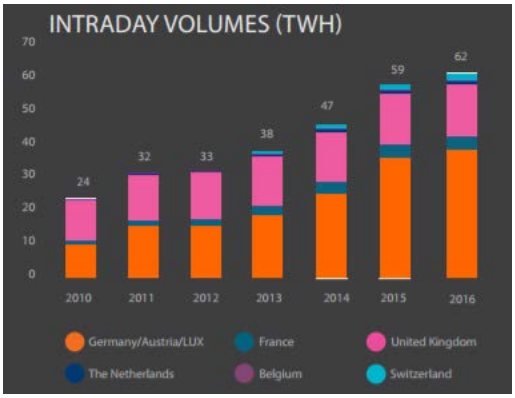


Figure 51: Intraday volumes at EPEX over time in Germany, Austria, Luxembourg, France and Switzerland (EPEX, 2017).

In addition, to the increasing irrelevance of ROM, adding even more scenarios to the simulation would dilute the results. A clear analysis of the outcome and an isolation of individual effects would have been much more difficult. Adding the same price scenarios to our optimisation as for power exchange prices would have multiplied the number of optimisation by a factor of 9. Thus, the variation of the price and spread power exchange scenarios on its own gives us much more value than the additional integration of ROM sensitivity.

5.4.3.2 Other optimisation settings

One important setting for the batteries are not allowed to get feed by the grid. Thus, we do not use the for speculation on power exchange prices. Batteries can however be used for keeping power band for ROM. They can reserve a certain power band to be called if needed by the TSO together with the flexibility of boilers. To assure that the households are always able to offer the tertiary reserve power offered in a case of activation, we always hold back 120% of the amount in the accepted bid. One ROM bid can consist of the flexibility from several groups and is not bound to one. Please note that the peak constraint for each group is not affected by the ROM capacity.

5.5 Results

As described above, we run 66 different prices, spread and aggregation scenarios after simulating the load data. Including the three optimisation steps, we are left with 198 results, which will be explained in the following sections. The exploitation of flexibility will be analysed together with its cost side (CAPEX and OPEX) in chapter 10 as a final analysis.

5.5.1.1 Representative days optimisation

The optimisation described in the previous sections are all executed for each of the representative days individually and then summarized. Thus, we get total load and procurement cost for each scenario, which we extrapolate to one full year. As an example, we look at the aggregated results for the mid-price, mid-spread scenario, which are presented in Table 10. We start by looking at the base case. The base case is the simulated load profiles for all households, multiplied by the electricity price. This is the costs that appear when an Aggregator would buy the electricity from the power exchange without any interference into the end consumer's consumption behaviour. Following, we have applied the five-stage optimisation approach described in the last chapter. The aggregated outcome for the different markets is presented from column *Total* to *PB short*. Power exchange shows the purchasing costs for the total load of all integrated households and the residual load based on the optimised boiler consumption.

Number of houses	Base Case	Total costs	ROM up	ROM down	Power Exchange	PB long	PB short	PB long	PB short
	[EUR]	[EUR]						[MWh]	
1000	277'942	276'789	-	-	276'425	-	364	3.597	3.637
2000	523'008	520'255	-	-	519'975	-	280	2.392	2.804
5000	1'446'948	1'439'564	-	-	1'439'318	-	246	1.944	2.464
10000	2'710'032	2'695'349	-	-	2'695'151	-	198	1.611	1.977
20000	5'805'373	5'775'555	-	-	5'775'388	-	167	1.217	1.667
50000	6'713'533	16'632'176	-	- 7'534	16'639'551	-	159	0.833	1.593
200000	63'855'593	63'531'834	- 277	- 32'832	63'564'782	-	161	0.660	1.611
500000	160'699'150	159'890'996	- 1'045	- 80'373	159'972'278	-	136	0.579	1.361

Table 12: Optimisation results for the mid-mid (price-spread) scenario for the 18 representative days compared to the base case.

The *ROM up/down* shows the profits that are made on the ROM markets for the power provision for positive and negative power bands (lot size of at least 5 MW). The columns *PB long/short* shows the costs for power balancing based on the volumes of balancing power purchased, shown in the last two columns. The *Total Costs* are the sum of the five outlined costs and profit points. The difference between the *Base Case* and the *Total Costs*, represent the value added from the SEMIAH DR technology. The same calculations and procedure have been applied for all the other price and spread scenarios.[14]

The scenarios given in Table 10 are based on the real prices in 2016. They can be considered as status quo scenario. We see that the power balancing costs are small in comparison to the rest of the costs and thus are not the most important. The reason for that is partly to the setup of the optimisation. Interesting to note are the revenues from ROM. Only for 50'000 and more households, it is possible to bid into the ancillary service market. Not in one scenario with an aggregation below 50'000 households, a participation on ROM is possible. The reason for this is that we only control boilers. Boilers consume electricity only for a very short amount of time but several times a day. Hence, we require a huge aggregation of households so that it is difficult to offer continuous power bands over several hours or even the whole day. Even though, we have integrated batteries, we still need a very high level of aggregation to bid into ROM. The share of houses with batteries installed is not very high though. The performance at the ROM could be improved in different ways. Firstly, we could integrate larger batteries. Secondly, we can increase the number of batteries. Thirdly, we can integrate more DR devices such as heat pumps. Those or other heating systems are likely to improve the situation. As a consequence of the ability to participate at the ROM with 50'000 or more households, we expect a jump from 20'000 to 50'000 households for the value added of flexibility.

To assess the value added of the SEMIAH technology, we look at the differences between the base case and the Total costs from the optimisation results. Since absolute terms are difficult to interpret and do not allow us to compare different aggregation levels, we look at the value added per installation per day as shown in Table 11. The lowest numbers are marked in green colours, while the highest numbers are highlighted in red colours. As a first result, we can easily see that the largest increase in value comes from the high spread scenario, i.e. price volatility. A higher general price level also leads to better results but does not have the same effects as the spread. The level of aggregation has the lowest impact on the value added. This is apparent from the low variation within

[14] A detailed summery of all results can be found in Annex B.

a single price scenario. When adding more controllable DR devices to the system, the ranking of impact may change.

level	low	low	low	mid	mid	mid	high	high	high
spread	low	mid	high	low	mid	high	low	mid	high
#inst									
1’000	0.00	0.02	0.06	0.02	0.06	0.15	0.06	0.15	0.32
2’000	0.01	0.03	0.08	0.04	0.08	0.16	0.08	0.16	0.33
5’000	0.02	0.04	0.08	0.04	0.08	0.17	0.08	0.17	0.33
10’000	0.02	0.04	0.08	0.04	0.08	0.16	0.08	0.16	0.33
20’000	0.02	0.04	0.08	0.04	0.08	0.17	0.08	0.17	0.33
50’000	0.03	0.05	0.09	0.05	0.09	0.17	0.09	0.17	0.34
200’000	0.03	0.05	0.09	0.05	0.09	0.17	0.09	0.17	0.33
500’000		0.05			0.09			0.17	

Table 13: Value added of the SEMIAH DR technology per installation and per day. From the three factors, price volatility, price level and aggregation level, the price volatility has by far the biggest impact on the value added (in EUR).

We can again clearly see in Figure 52 that the future development of the power market prices is of great importance for the profitability of DR systems which exploit flexibility on the markets and not necessarily by the aggregation of households. In the graph, the aggregation effects are reflected by the individual curves themselves. The steeper the slope the stronger the effects. The slopes mostly flat though. The aggregation effects are mostly appearing on the lower aggregation levels, between 1000 and 5000 households, as visible. For a larger number of aggregated households, the value added per installation per day stays almost linear. Only when going from 20’000 to 50’000 houses, we can see a little jump because the Aggregator can participate on the ROM market. That is in order with what we expected above. The effects of price volatility and level are reflected by the distance of the different curves.

Overall we can see that the revenue possibilities from boiler based flexibility is relatively low and the attractivity for price optimisation is limited. No matter what the cost side will look like, we will deal with small margins. The low-price scenario offers at its maximum (high spread) 9 EUR cents per day per installation and only if we have a high price volatility. Even the best scenario gives us at maximum 33 EUR cents of savings. From plotting the data, we see that aggregation effects only appear in the lower regions of aggregations and when the thresholds of ROM provision is exceeded.

From looking at the results of the representative days, we can already see that margins are rather small no matter what the costs side will look like. Price level and volatility are of great importance for the value of flexibility. However, the full extent of the simulation and optimisation will only be clear after extrapolating the data to one full year and addressing the cost side.

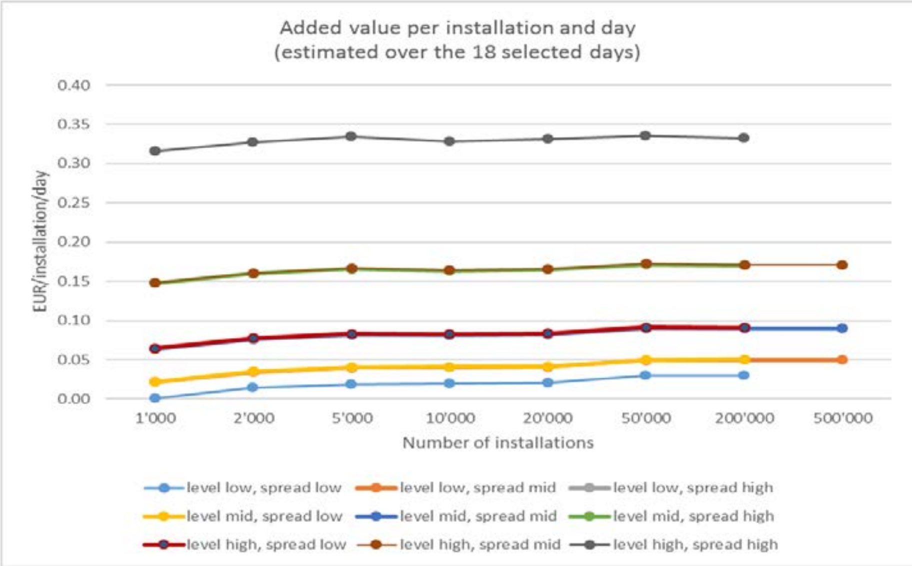


Figure 52: The added value of flexibility per installation per day show only small differences in aggregation levels but large differences in prices levels and spread development. The slope of the curves reflects the effects of the different aggregation levels, while the distance between the individual curves stands for the effects of price level and price volatility.

5.5.1.2 Extrapolation for one year

The benefits from the SEMIAH technology can easier be seen when looking at one full year than only a few representative days. Hence, we have extrapolated the results described in the previous section to one year. The yearly value added can be compared to the costs of the DR technology for a full evaluation (compare Chapter 6.1).

		Base Case costs EUR		OPTI costs EUR		Savings (OPTI) EUR		
#inst	Price Scenario	Selection	Full year	Selection	Full year	Selection	Full year	Factor
1'000	1	135'650	3'097'359	135'634	3'097'210	16	149	**9.39**
1'000	2	138'971	3'178'773	138'578	3'171'512	393	7'261	**18.47**
1'000	3	145'614	3'341'600	144'467	3'320'085	1'147	21'514	**18.76**
1'000	4	271'299	6'194'719	270'902	6'187'358	398	7'361	**18.52**
1'000	5	277'942	6'357'546	276'789	6'335'923	1'154	21'623	**18.74**
1'000	6	291'227	6'683'199	288'567	6'633'068	2'660	50'131	**18.84**
1'000	7	542'599	12'389'439	541'435	12'367'597	1'163	21'841	**18.77**
1’000	8	555'884	12'715'091	553'213	12'664'745	2'671	50'347	**18.85**
1'000	9	582'455	13'366'399	576'767	13'259'036	5'687	107'363	**18.88**

Table 14: Derivation of the scaling factor based on the 1'000 households one year optimisation for all price scenarios.

To have a point of reference, we simulated for one aggregation level the nine price scenarios for a whole year based on the same principles above. From this 365 days of optimisation, we could then derive the total costs as we did for the representative days. The total costs from the optimisation were then compared to the base case costs for one full year as shown in Table 12. From the ratio between the savings from the representative days and the fully year saving, we derived the scaling-factor. The scaling factor was then used to extrapolate the representative day savings of the other simulations to one year. While the scaling factors for the most scenarios are relatively constant, the factor for the first scenario is half the size of the others. This can be due to precision effects for this scenario. The savings in price scenario one was so small that optimisation errors become very high. Thus, the significance of the first price scenario is questionable. The scaling factor is smaller than the proportional multiplier between the representative days and the days of the year (365:18), which would be approximately 20.3.

The value added (savings) for the optimisation were then divided by the number of households for each scenario, so we receive the value added of flexibility per installation. The number are presented in Table 13. We see the same pattern as we did in the previous chapter, since we scaled the results by a not strongly varying factor that is the same within each price scenario. Therefore, we see again only little variation between the different aggregation levels but much difference between the price level and spread scenarios.

However, the numbers are much more interpretable and give us a good idea of how much value can be created in each household. On average the value added is approximately 37 EUR while the median is at approximately 28 EUR. The spread of the possible value is large and the value added can go from almost zero up to a 113 EUR. The standard deviation is about 31 EUR. Considering a mean of 37 EUR, a standard deviation of 31 is high.

level	low	low	low	mid	mid	mid	high	high	high
spread	low	mid	high	low	mid	high	low	mid	high
#inst									
1’000	0.15	7.26	21.51	7.36	21.62	50.13	21.84	50.35	107.36
2’000	2.35	11.43	25.65	11.73	25.80	54.15	26.22	54.52	111.12
5’000	3.17	13.18	27.56	13.40	27.68	56.28	28.09	56.60	113.68
10’000	3.36	13.40	27.39	13.60	27.52	55.42	27.92	55.72	111.43
20’000	3.49	13.68	27.83	13.90	27.95	56.05	28.33	56.35	112.44
50’000	4.98	16.44	30.40	16.64	30.50	58.20	30.88	58.49	113.91
200’000	5.09	16.59	30.31	16.79	30.34	57.80	30.79	58.09	112.78
500’000		16.49			30.30			57.89	

Table 15: The value added by the SEMIAH technology per installation for a full year (in EUR).

Considering that we only control for boiler and the use of some batteries, this is not a bad result. We can assume that the integration of heating or cooling systems should at least bring the same if not more value. Especially an increasing price volatility and a higher demand for electricity (rising prices) are promising to make the value of DR larger. It seems that so far the most important to evaluate the value of flexibility is to know the characteristics of the future electricity price. Especially knowledge about the future volatility would be of a great help.

To sum up the results section, we can say that we derived some interesting findings about the value added from the SEMIAH DR technology. First, optimising boiler flexibility against the power prices does not create enormous revenue streams. However, continuously optimising boiler consumption and a large enough aggregation allows to create some potential savings and some additional income from ROM. The integration of more batteries and more rooftop solar panels could definitively improve the situation. Power balancing effects are relatively small, which lies to some extent in the nature of the optimisation. From the investigated effects, we can see that the largest impact on the value comes from the price volatility, followed by price level and then by aggregation level of households. It makes sense that higher differences in prices also lead to higher incentives for shifting consumption. It also seems clear that the higher the prices the more attractive it is to change consumption behaviour. The aggregation level is mostly beneficial for the provision of control power bands at ROM. Since this is difficult with boilers only (and some batteries), the benefits of aggregation are small. For the price optimisation, the aggregation level gives the households the opportunity to provide its own generated PV excess power to other houses (within groups). This is more likely to happen the more houses participate. Thus, we have a small effect from the aggregation of houses. The put the value added in context, we consider now the cost side, so that we can assess the value of flexibility in Chapter 6.2.

To improve the accuracy of the optimisation, we have made a second optimisation where we improved the base case scenario. For that residual load within the households was adjusted by a seasonal factor based on the real transformer load data in Engene Norway (ten-year average), which is almost only reflecting household patterns. From that we had more realistic consumption patterns for the households in the base case that take seasonal fluctuation better into account. The improved yearly optimisation was executed for the 1000 household aggregation level. The outcome can be seen in Table 1. We achieved an improvement between 101% to 108%. In the first scenario, we have an improvement of 436%, which is mostly to explain by precision effects. Since the savings for the selection is only 149 EUR, small absolute errors can have a huge effect in relative terms. The improvement with the refined results are good but they not change the overall picture or tendencies, especially when we are going to compare the value added to the costs side.

		Base Case costs EUR		OPTI costs EUR		Savings (OPTI) EUR		
#inst	Price scenario	Full year	Full year (improved)	Selection	Full year (improved)	Selection	Full year (Improved)	Improvement
1'000	1	3'097'359	3'024'015	3'097'210	3'023'367	149	648	**436%**
1'000	2	3'178'773	3'105'017	3'171'512	3'097'210	7'261	7'807	**108%**
1'000	3	3'341'600	3'267'021	3'320'085	3'244'855	21'514	22'165	**103%**
1'000	4	6'194'719	6'048'031	6'187'358	6'040'135	7'361	7'896	**107%**
1'000	5	6'357'546	6'210'034	6'335'923	6'187'804	21'623	22'230	**103%**
1'000	6	6'683'199	6'534'041	6'633'068	6'483'111	50'131	50'930	**102%**
1'000	7	12'389'439	12'096'062	12'367'597	12'073'670	21'841	22'392	**103%**
1'000	8	12'715'091	12'420'069	12'664'745	12'368'996	50'347	51'073	**101%**
1'000	9	13'366'399	13'068'084	13'259'036	12'959'625	107'363	108'459	**101%**

Table 16: Improved results of yearly optimisation in comparison to the previous yearly results.

6 Demand & Response in an economic context

We have gone through the assessment of individual topic that influence the feasibility of DR concepts in the future such as the current set up of electricity markets in Europe, possible market frameworks and business layers, as well as a quantitative assessment of the possible value that can be created. In this last chapter, it is the aim to unite all those topics and derive the value of flexibility dealt with in this paper. Further, topics such potential business models, market frameworks and regulations are assessed.

6.1 The costs of DR

To put the simulation results into the right context, we calculated the cost of the SEMIAH technology depending on the level of aggregation. This allows us to get a feeling for the economic feasibility of DR on a household level. The costs calculated are for a household only controlling hot water boilers. Some households are equipped with rooftop solar. A small share of the rooftop solar houses also includes a battery to store the self-generate electricity.

To calculate the CAPEX, we start with the derivation of the installation costs per households with and without PV as seen in Table 1Table 10. For the houses without PV the material costs are around 95 EUR and for houses with PV about 160 EUR based on information from DEV. The prices are estimates for large quantities (>1000). The houses with PV need a more sophisticated prosumer meter instead the normal meter reader. For the installation of the hardware, we assumed 1 hour for the houses without PV and 1.5 hours for the houses without PV. To calibrate the software remotely, we assume work of 0.75 hour for the houses without PV and one hour for the houses with PV. The times are based on experiences from the SEMIAH pilot installations, assuming some learning effects will appear. The salaries are Norwegian average plus a surcharge (Salaries WIki, 2017). We did not consider Swiss salaries, since they are so much higher than the European average. As an installation costs per household we receive 147.5 EUR without PV and 295 EUR with PV. For the houses including batteries, we take the PV installations as a starting point and add a fix surcharge of 100 EUR. This will cover additional material costs for a smart batters control device and the additional time used for installation and calibration. Thus, a household equipped with the SEMIAH DR system including PV and battery is expected to cost 245 EUR.

Installation costs including PV			Installation costs boiler control only		
Boiler installation material cost (Gateway, smart Relay, temperature sensor, prosumer meter)	160	EUR	Boiler installation material cost (Gateway, smart Relay, temperature sensor, meter reader)	95	EUR
Time for installation	1.5	h	Time for installation	1	h
Hourly rate electrician	30	EUR/h	Hourly rate electrician	30	EUR/h
Time for remote calibration	1	h	Time for remote calibration	0.75	h
Hourly rate IT technician	40	EUR/h	Hourly rate IT technician	40	EUR/h
Costs per installation	**245**	**EUR**	**Costs per installation**	155	**EUR**

Table 17: Costs for the installation of the SMEMIAH households including rooftop PV and not including rooftop PV. The material expenses are based on prices for large quantities from DEV.

After estimating the installation costs per household, we calculate the aggregated CAPEX and OPEX for the SEMIAH technology. To receive the total CAPEX per aggregation level, we summed up the costs for the three different types of installations multiplied by an efficiency factor (compare Table 10). The costs for the different types of installations are multiplied by the total number of households and the share of simulation type. The efficiency factor decreases in the number of households and corrects the costs for economics of scales. As a maximum, we assume a 20% decrease of the total CAPEX when aggregating 500’000 households. We consider this as justified since an installation for 500’000 households is leading to a high level of standardisation and efficiency. Thus, we get an installation cost per household from 237 EUR to 185 EUR. The costs are relatively low but we should keep in mind that we are only controlling boilers and the batteries, which are only installed in about 5% of the houses. Adding an additional controllable element as heating, can increase the CAPEX significantly.

Scenario	Efficiency Factor	CAPEX [EUR]	CAPEX per installation [EUR]	OPEX [EUR]	OPEX per installation
1000	100%	236'940.00	**236.94**	149'000.00	**149.00**
2000	100%	463'890.00	**231.95**	150'000.00	**75.00**
5000	100%	1'145'840.00	**229.17**	221'000.00	**44.20**
10000	95%	2'167'076.00	**216.71**	276'000.00	**27.60**
20000	95%	4'328'603.00	**216.43**	454'000.00	**22.70**
50000	90%	10'304'483.00	**206.09**	784'000.00	**15.68**
200000	85%	39'092'929.50	**195.46**	2'570'000.00	**12.85**
500000	80%	92'187'860.00	**184.38**	6'074'000.00	**12.15**

Table 18: Aggregated and average CAPEX and OPEX estimations for the SEMIAH DR technology defined for the simulation.

To calculate the OPEX, we first must estimate a certain kind of licence fee, which is payed to the entity providing the SEMIAH technology. We assume the SEMIAH DR technology will be offered as a Saas. The licence fee assumed here is consisting of a fixed and a variable part. The fixed part equals 30’000 EUR and the variable part is 1 EUR per installation. Secondly, we estimate a certain number of technicians and computer technicians working for the Aggregator. If 5% of the installations will be corrupt over one year, we are left with 250 cases for 500 clients. A single technician is usually able to solve more than one case a day. Hence, we allow for one full time technician per 5000 clients, what leaves us with 100 technicians for 500’000 households. To run the software and do the administrational things a certain amount of computer technicians is required. However, those tasks are highly automated and only require a few resources, since also most issues can be dealt with by the technicians themselves. To handle the system for 500’000 people, we assume 8 full time positions. Based on those estimations, we get OPEX between 149 EUR and 12.15. From only looking at the OPEX per installation, we see that its starts to become interesting for DR with at least 10’000 households.[15]

The costs shown here are the direct cost a SEMIAH DR system would cause without any overhead costs. Depending on who would integrate the OPEX are varying. So could for example a new entity have to employ additional people for trading, marketing or sales, while an existing energy supplier already has that in place. For the business cases in Chapter 6.3 the cost described here are applying to all players. Depending on the business model and player some additional costs can appear but this is difficult to define.

6.2 The value of flexibility

To calculate the true value of flexibility, we must consider the benefits and the costs side. In the previous two chapter, we have derived estimates for both. Based on a NPV calculation, we will now see whether an investment into the SEMIAH technology with boiler only control is profitable.

[15] More detailed numbers can be found in Annex C.

As an investment costs at time zero, we use the CAPEX for each scenario calculated before. The cashflows are the sum of the yearly value added and the OPEX. The investment horizon is chosen to be 5 years. Even though the devices can last much longer, they probably are going to be replaced by new hardware after a certain time. We can compare it to the router at home for the internet. They also often get replaced before they do not work anymore due updates of hardware and software. Cash flows are considered as constant since we are looking at five years only and we assume we have a solid customer base that does not fluctuate too much. As an interest rate we have chosen 3.5%, which are common capital cost in the energy industry in 2016/2017 (PWC, 2017).

The results of the NPV calculations are presented in Table 17.[16] Only a very few of the optimistic scenarios regarding price level and spread turn out to be positive. In most of the times we would not implement the DR technology given the circumstances and assumptions described here. Applying the improved model with a revenue of 108% from the initial one does not change the picture. The result seems first a bit disappointing but when looking at it closer it starts to become more promising.

level	low	low	low	mid	mid	mid	high	high	high
spread	low	mid	high	low	mid	high	low	mid	high
#inst									
1000	-877'298.4	-799'737.9	-644'286.2	-798'644.0	-643'107.3	-332'199.7	-640'721.1	-329'844.5	291'973.5
2000	-1'051'308.1	-853'265.3	-543'185.1	-846'787.7	-539'878.8	78'450.2	-530'746.2	86'537.8	1'321'080.6
5000	-1'898'062.4	-1'352'207.6	-568'220.3	-1'340'528.5	-561'667.1	997'912.8	-539'397.9	1'015'465.9	4'127'923.9
10000	-2'931'140.5	-1'836'687.9	-310'386.0	-1'814'981.1	-296'015.8	2'746'361.5	-253'349.5	2'779'088.7	8'855'075.9
20000	-5'402'000.0	-3'177'974.0	-91'916.9	-3'130'951.5	-67'017.7	6'063'024.8	16'901.6	6'128'768.0	18'362'904.8
50000	-10'661'631.8	-4'411'702.1	3'198'425.5	-4'302'211.3	3'255'554.2	18'359'353.5	3'460'017.3	18'517'422.6	48'739'083.8
200000	-37'883'147.1	-12'794'143.0	17'139'989.1	-12'366'767.7	17'203'623.6	77'084'845.8	18'176'451.0	77'712'291.3	197'007'299.6
500000		-25'674'936.6			49'643'067.7			200'097'518.8	

Table 19: NPV calculation results for the SEMIAH DR technology over a five-year investment horizon.

To see how much more revenue is needed that the SEMIAH technology starts to becomes profitable, we multiplied the yearly revenue by a factor. Table 18 shows the NPV values for the scenario with a revenue of 250%. The DR technology already looks much more attractive, especially from an aggregation level of 50’000 households upwards. In optimistic price scenarios, even the aggregation of 2’000 households is profitable.

level	low	low	low	mid	mid	mid	high	high	high
spread	low	mid	high	low	mid	high	low	mid	high
#inst									
1000	-877'298.4	-799'737.9	-644'286.2	-798'644.0	-643'107.3	-332'199.7	-640'721.1	-329'844.5	291'973.5
2000	-1'051'308.1	-853'265.3	-543'185.1	-846'787.7	-539'878.8	78'450.2	-530'746.2	86'537.8	1'321'080.6
5000	-1'898'062.4	-1'352'207.6	-568'220.3	-1'340'528.5	-561'667.1	997'912.8	-539'397.9	1'015'465.9	4'127'923.9
10000	-2'931'140.5	-1'836'687.9	-310'386.0	-1'814'981.1	-296'015.8	2'746'361.5	-253'349.5	2'779'088.7	8'855'075.9
20000	-5'402'000.0	-3'177'974.0	-91'916.9	-3'130'951.5	-67'017.7	6'063'024.8	16'901.6	6'128'768.0	18'362'904.8
50000	-10'661'631.8	-4'411'702.1	3'198'425.5	-4'302'211.3	3'255'554.2	18'359'353.5	3'460'017.3	18'517'422.6	48'739'083.8
200000	-37'883'147.1	-12'794'143.0	17'139'989.1	-12'366'767.7	17'203'623.6	77'084'845.8	18'176'451.0	77'712'291.3	197'007'299.6
500000		-25'674'936.6			49'643'067.7			200'097'518.8	

Table 20: NPV calculation results for the SEMIAH DR technology over a five-year investment horizon with a revenue increased by the factor 2.5.

[16] More detailed results can be found in Annex D.

All low-price scenarios are still not profitable. The 250% revenue might seem high but we are only looking at boiler. When looking at households with electric heating (e.g. heat pumps), boilers are not a that large fraction of consumption. In Norway, hot water contributes only to about 16% of the electricity consumption in a household, while space heating is about 63% (Bjørn Grinden, 2009). Even though number are not in all countries as high as in Norway, the tendency is clear. Hence, an increase in revenue by 2.5 times seems realistic when including the heating system into DR. In addition, the possibility of providing ROM at a lower level could lead to a jump in revenue.

In integrating additional devices into the DR system, additional costs appear. The additional costs will be lower than the one calculated above. Most of the system and resources are already in place, so that the new costs mostly consist out of the material costs and some installation and calibration time. Consequently, we are optimistic that if more devices are integrated into the service it will become profitable. A large factor is also the future price development and the importance of non-monetary benefits to the end consumer.

6.3 Possible business models

We are now describing three different business models, with their benefits and challenges for parties involved. The models are derived from the knowledge and findings accumulated in this work. The business models are based on USEF and the business layers identified in Chapter 4. Each business model focus on mainly one specific layer of exploiting flexibility. In principle, an Aggregator could offer all kinds of services. However, the amount of flexibility and the potential revenue from it is limited. There are several services that offered in all presented models, e.g. remote heating control or consumption insight services. For many aspects of the business models presented, there is already some examples of companies realising them. We will then give an example.

6.3.1 Option 1: Balancing the grid

The first business model is about aggregating flexibility of households to sell them to DSOs and DSOs. TSOs will use the flexibility services to balance the transmission grid and provide security of supply. For DSOs, new flexibility markets will be created as described in Chapter 4. The DSO will buy flexibility from an aggregator to balance the grid in times of congestion or he can purchase flexibility to do peak-shaving. The latter option will allow him to reduce grid costs to the TSO, avoid or postpone investments and increase its overall efficiency. The potential of peak shaving even only with boilers could be seen in Funk & Wood (2017).

Consequently, we assume that the flexibility of the participating households is fully utilized by the Aggregator. The Aggregator sells the flexibility to TSO and DSOs and provides the households some energy services in return. The services can be a smart home network, remote control of several devices or possibilities to increase the efficiency level of the house. There are many possibilities but the most effective benefits are usually monetary. Thus, it could be very practical for an energy supplier to take over that role. He could offer his costumer privileged tariffs if they become part of the DR network. The role is not limited to the supplier though. It can be taken over by an independent player, and ICT company or even by the DSO itself. Especially for an ICT company it could be interesting, since they already have an existing connection to the houses and they are not in a conflict with themselves. The ICT company does not benefit from making the household buying electricity to prices when it is cheaper on the whole sale market, even though it makes an end consumer worse off.

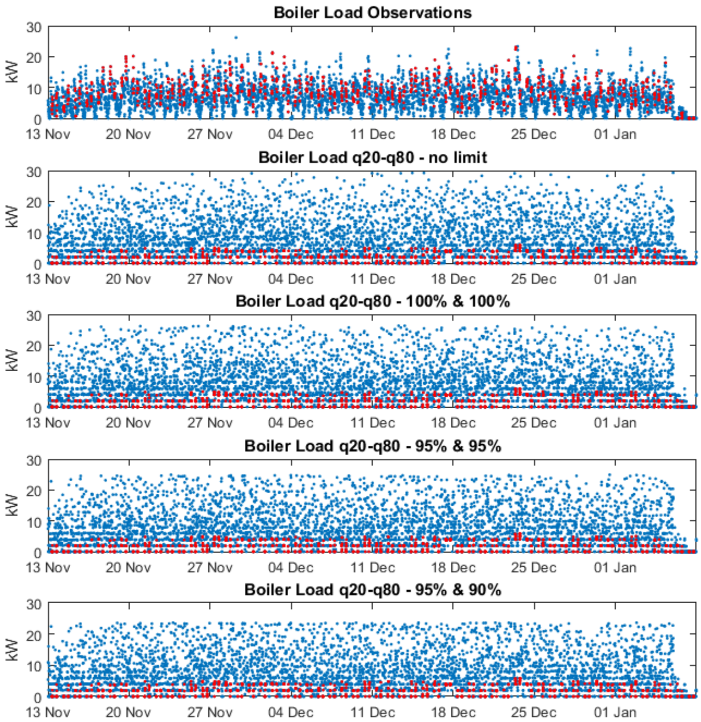


Figure 53:The potential of peak shaving shown during specific hours of the day. The red dots are all the aggregated boiler for each time step from the optimisation in Funk & Wood (2017). The first plot is the observed data while the other four plots show the optimisation against the price while putting a constraint on certain of the day. As we see it is possible to reduce the boiler consumption during those hours to a minimum.

The business model is only exploiting the grid layer and combines the market for ancillary services, stability services for DSOs and peak shaving. While we could show in WP9 that peak-shaving is a feasible business case (compare Figure 53), the provision of ancillary services cannot yet be verified. At least with boilers only, it is not possible to participate at ROM. From other Projects, MIS knows that there is a good chance to deliver control power if heat pumps and batteries are included as well.

The CAPEX can roughly be compared to the estimation in Chapter 6.1. In case the Aggregator will be a complete new start up, those costs will be a lot higher since even more infrastructure and so on must be established. The same is true for the OPEX. In case, an existing energy supplier is implementing such a system, the trading team can take over certain tasks. For a new company, however, for those tasks new people need to be hired. If the energy services provide are a very strong value added, the aggregator could even create income by charging them a fee to be part of the whole system.

To implement the business models as of today is difficult since there is no such a thing as flexibility markets for DSOs yet. Regulators and DSO would have to start required pilots to effectively test the approach and to work out the policy required. At least and Aggregator can already participate at ROM and provide the energy services to its customers. The company Swisscom Energy Solutions has already such a concept in place called tiko. The concept is based on providing smart energy services to their clients while they are part of the tiko pool. The pool is used to participate at the Swiss tertiary control reserve market. Interesting is that the prosumers pay for the installation of the required software upfront. If they would like to not participate in the pool, the can but the installation costs are even higher (Swisscom Energy Solutions, 2017).

6.3.2 Option 2: Procurement costs minimisation

The second business model targets the minimisation of the electricity procurement costs. Consumption of the aggregated households is shifted to times with low power prices. Since it is not profitable to install such a system for one single household individually, it will be managed by an Aggregator. The Aggregator has two options to deal with the benefits from the household flexibility. One is that the Aggregator passes the profits on to the households and takes a share or a fixed fee for himself. The other would be that the households get a better electricity tariff and the Aggregator can keep all the profits for himself.

Households do not need to be prosumers but they can be. In this business model, the Aggregator needs to be the energy supplier since otherwise the end consumer would not profit from the optimisation. One exception is when energy supplier provides energy tariffs coupled to the market prices to his customers. In such a case, a new party, an ESCo could equip households with the necessary technology to follow the energy tariffs from the supplier. The households would have to pay a fee to the ESCs or share their savings with them. ESCo could be started by any company, i.e. an ICT company, which again has already a connection to the households.

DSOs could also play a role in the whole game if the offer the right tariffs so that the consumer have an incentive to change consumption in a way they increase their grid utilisation. Tariffs can either can be based on time of the day or the maximal capacity used over a certain period. Important is that the grid tariff is based on capacity or time of consumption rather than energy volumes.

The benefits for households are simply saving on the energy bill. Again, the provider of the technology could also give the households further incentives with smart energy services. The Aggregator can create additional income from making the end consumer better off. In a fully liberalized electricity market this could be very essential to increase customer loyalty. DSO could increase their efficiency and avoid congestion as well as grid overload. The concept bases the sense on USEF that it takes over most of the roles, even though it does not include a new decentralized flexibility market. Option one and two could easily exists next to each other. While some households rather contribute to grid stability, others rather profit from price advantages. Even a mix of both is possible but unlikely.

From this work and Funk & Wood (2017), we know that boiler DR is not the best for market price optimisation. New grid tariffs could increase the incentives for boiler price optimisation. For this approach the most benefits will come from heating and cooling system since they contribute the most to power consumption of households. This approach could also be very attractive for larger residence buildings with high energy costs or small to medium sized businesses.

6.3.3 Option 3: Self-Sufficiency

The third approach base on the idea to make certain subgroups or individual households of the grid as independent as possible. This would increase the decentralisation of electricity markets and take away some pressure on the grid. For version A the self-sufficiency of single households is tried to be maximised. For version B the self-sufficiency of whole neighbourhoods and communities is maximised while the individual houses can be highly dependent on their partners.

6.3.3.1 Version A: Self-sufficient Prosumers

For the first version of the self-sufficiency business model only prosumers can be considered. It is a necessity that some electricity is generated by the household itself, so that the it can become more independent from the grid. The technology used for electricity production is irrelevant but likely to be solar panels. An installation of the battery helps a lot as well. The prosumer then has two possibilities to increase its self-sufficiency level. The first way is to consume electricity then when it is consumed and the second ways is to store energy in batteries or with hot-water boilers. Both will reduce the amount of power consumed or feed-into the grid. However, a total independence from the grid is unlikely but smaller or at least not larger connections are required.

The DR technology can then be provided by an ESCo that get a periodic or fixed fee for the service. Another option is the Aggregator that uses left-over flexibility to optimise the procurement costs on the markets or by distributing excess supply among its clients. This could increase the efficiency of the energy supplier or, in case the service is sold to the prosumer, additional revenue streams.

This time the role of the Aggregator could be taken over by any entity such as energy supplier, ICT, the ESCo, or even a complete new player. In case, the energy supplier was the Aggregator, he may improve again client loyalty. The role of the DSO is similar as in model number two. The DSO should target his tariffs more on capacity than energy. Because self-sufficiency increases, the pressure on their gird lower as well, what is appreciated. Due to the situation that less people will pay for the gird, tariffs are likely to rise and people with not a higher self-sufficiently will need to pay for it. To some extent this makes sense since grid tariffs are based on the cost-by-cause principle. Consequently, more and more people will start increasing their level of self-sufficiency. Eventually, we end up in a situation where only a very few households pay most of the grid costs, what is also not the idea. Thus, a situation like this is to avoid.

To increase the level of self-sufficiency for households is definitively possible by a smart system. A battery helps a lot. We saw that boiler can be shifted over time significantly and can be reheated when there is also energy produced. But also, other processes such as charging an EV can be postponed or delayed by a certain time.

6.3.3.2 Version B: Self-sufficient neighbourhoods

The second option of the self-sufficiency business model is aiming to increase the independence from whole communities or neighbourhoods or even make them complete autonomous from the grid. The idea behind is decentralisation of the electricity production and less reliability on the grid. It is easier to arrange the consumption between a little community than for a whole city. Is security of supply guaranteed on such a low level, it is also much higher in the grid layers above.

To make the concept work, many of the participants one neighbourhood need to be prosumers but not all of them. The target of the group is to purchase as little energy from the grid as possible or none. Some households or buildings produce more than they can consume some less. The idea is not any direct cost optimisation. The objective is to meet local demand by local supply. The electricity can be either traded between the houses or the whole power system belong to everybody and people just contribute with payments depending on the amount of energy consumed.

The Aggregator functions as a market facilitator and provides the DR system and deals with the optimal allocation within the group. In case, the households can sell electricity with each other, the Aggregator provides the right platform for the participants to do so. This time it is rather unlikely that the role of the Aggregator is taken over by an energy supplier especially in the beginning. Over time, when markets change and energy supplier look for new business model they could start offering services like this as well. Better to not sell that much energy but earn money via another channel than losing all the customers.

The role of the Aggregator/Market Facilitator is more likely to be taken over by an ICT company or an ESCo. If such a framework would become reality, DSO must update the structure of their distribution grids, since they have new requirements. DSO would still be maintaining the local grid and the connections in-between. In case the communities become relatively large, the DSOs could even organise a grid balancing market/system. Even though, the last idea is oriented at USEF, the rest of the concept is not something that is well covered by the highly advanced future power market framework.

The possibility of such a concept is not easy to assess, even though it could be the future of our energy markets at least residentially. It definitively is not a short-term concept that can be implemented in a few years. It rather is a long-term process that would slowly change the structure of our power market. The consequences of such as system would definitively help to reduce the need for ancillary services and other system balancing mechanisms. The approach would also help to raise awareness for electricity production because people can see where it is produced and with what technology.

6.4 A comment on policy and regulations

Power markets in the EU and all over Europe are about to become more integrated. Nevertheless, policy and regulation frameworks are still significantly different even after years of harmonisation. The feasibility of a business model still depends massively on the market framework and regulation in each country. Some differences are due to different circumstances and requirements to the grid what therefore makes sense. Some of them are just based on historical differences but do not necessary play a role anymore. Such differences should be removed and harmonised. The easier it is to apply a business model to different countries; the faster new technology will become marketable.

The full market liberalisation in whole Europe, will also help to drive the development of smart services and technologies since energy suppliers are exposed to competition. The need to provide more service and a cheap tariff lead to more innovation. Also, new market oriented tariffs are popping up in countries with fully liberalized markets such as Norway and Germany. DSO tariffs vary a lot among countries. Most of them should be more capacity based. To change that the initiative from the regulator is required. In some countries DSO are not able to change their tariffs even if they want to, since the regulation does it not allow. In other countries, DSOs have become passive. When capacity or dynamic tariffs are in place, people who rely on the grid most will pay more for it.

Dynamic energy and grid tariffs and more harmonized markets will already create an environment that is much more DR friendly. Another factor that will drive the development of smart solutions for DR is the continuous electrification of devices such as heating systems, transportation or manufacturing. The more devices are electrified the higher demand, the higher prices. The more electrification the more possibilities to increase the efficiency for their consumption. The regulator should drive this, since it will also reduce CO_2 consumption (assuming the additional generation is based on green technologies). Thereby governments should not necessarily provide subsidies for certain technologies but they should ban or at least increase taxes polluting systems such as oil heating, fossil fuel based cars or polluting industries. Many of those things are happening or at least in the pipeline in some countries. Most of the countries are not progressing in these things yet.

Even though most markets in Europe are mostly liberalised now, the underlying framework does not much differ from the centralised one from 30 years ago. Most countries have not tackled yet the issue of decentralised electricity generation. Still many unclarities are in the industry where to go also regarding regulation. Not only are current policies often a huge burden for DR or do not even allow for it, a clear strategy where to go is missing as well. There are a few countries that are role models like Germany and Denmark but many let the industry wait and too much room for speculation. Clear progress regarding market frameworks would accelerate the development in the energy industry a lot.

Concluding, it can be said that the renewing and updating of regulation and policies in all European countries would be valuable to the industry and to drive the energy transition forward. However, regulators should not be throwing around with bans and subsidies. More effective would be the creation of a policy environment that does not have many burdens in place to move forward. Market should be able to allow for innovation and come over old and dusty structures. New and contemporary concept should be given a chance to establish themselves if successful.

7 Conclusion

The focus on WP9 was to connect SEMIAH to the market perspective. The understanding of markets is crucial for most technologies to become successful. For people of some fields profitability and marketability of a certain product are not of great importance to them. They are interested in the technical and or physical characteristics. People from other fields are exactly the opposite and do only care about the profitability of the product. Fact is that one cannot go without the other. To create the understanding for both sides is key and not always straight forward. Many companies, research institution and project know that issue. So, do we in SEMIAH.SEMIAH was in the first place very much focused on the development of a new, highly complex technology. Through the project interests from several side more and more also shifted to the business and economic side of the technology. In this report, we have tried to bring together the data from the pilots and their DR technology used with the business aspects. As with every new technology, the answer if it will work or not in the real world can only be answered when it is successfully placed and used. The SEMIAH technology has not reached marketability yet. As every other project, SEMIAH has over the last three years faced different challenges and is undergone some consecutive adjustments. Under this premise, it is obviously not possible to get a simple yes or not to the question if SEMIAH is profitable or not. In D9.2 and the master thesis from Funk & Wood (2017), it was however possible to derive some insights about important factors of DR and to get a realistic feeling, what is required to implement DR systems under different circumstances.

In the beginning of the D9.2, we have described in detail the electricity markets and their market frameworks in Denmark, Germany, Norway and Switzerland as they are in 2017. An even more detailed description of the Norwegian Power market is provided by Funk & Wood (2017). From the analysis of the different power markets, we have seen that they all look the same on the surface. When starting to look a bit closer, one realises how many small exists though and how difficult it is to define a typical European electricity market without being superficial. Especially for business models, the small distinctions are important. From the four SEMIAH member countries, only the Swiss power market is not liberalised yet. Ancillary services are quite country specific, even though the underlying principle is basically the same. The Nordic power exchange NordPool and the Central Power exchange EPEX are very similar and do not differ a lot. Balance energy pricing, subsidies and tariffs are differing a lot in all countries.

To have a common framework for electricity market, we were supposed to develop business model based on one of three market models based developed by EG3 in their first-year report. The models suggested were mostly dealing with the handling of smart grid data but not providing a full future market framework. Thus, we have described the models in the report but we did not use them as underlying models for business cases. Instead MIS has introduced USEF, a market framework for the integration of renewables and smart grid technology into the power market. USEF defines different roles, balancing mechanisms and flexibility markets. Some aspects of USEF are described in D9.2, while some other insights have been given in earlier deliverables.

Based on USEF, the market analysis and the needs of the SEMIAH members, we have introduced three different business layers that are describing on what levels and how flexibility can be exploited. This shows what value flexibility contains and how it could be exploited which is covering the first overall objectives of WP9 defined in the DOW. The layers have been identified by the SEMIAH consortium at the project meeting in Neuchatel in September 2015. The three business case layers are divided into service layer, grid layer and trading layer. The service layer stands for new services that can be created by the Aggregator or ESCOs for the end consumer. The services can increase a prosumers self-sufficiency or provide him monitoring or remote-control services. The service layer creates value added that is not monetary based for the household. For the provider of the services, it can be an additional revenue stream or increase the customer loyalty. The grid layer deal with exploitation of flexibility for balancing the grid or increasing the level of grid utilisation so investments can be avoided. The trading layer is addressing the benefits that can be made from selling flexibility on the different existing markets, power exchanges or ancillary service market. Hence, procurement costs are minimized or income is created.

After defining the three business case layers, we defined two different market frameworks that were underlying in the later simulation and the potential business models. The two possibilities for an aggregator to sell flexibility in a market as it is today and in a framework like USEF. The main difference is that USEF includes an additional market for flexibility with DSOs, while the current market frameworks provides opportunity to simply sell flexibility on the existing markets.

Following the analysis of the European power market and the identification of possibilities for flexibility exploitation, we executed the simulation to evaluate the economic value of flexibility. The idea was to simulate many households based on the SEMIAH pilot data to then optimize the controllable devices against the market and so exploit flexibility. Because there was almost none household with a connected heating system available, we had to focus on controllable hot water boilers. Thus, we simulated 1’000, 2’000, 5’000, 10’000, 20’000, 50’000, 200’000 and 500’000 households representing the SEMIAH pilot. Some of them included rooftop PV and batteries. The households were then aggregated to groups between 20 and 1000 households so that an optimisation in a realistic time could process the amount of data in a reasonable amount of time, and a solution could be found. The controllable devices of the aggregated groups such as batteries and boilers where then optimised against the power markets, ancillary service market and to minimize balance power. In a first step, the optimisation has only been run for representative days (weekdays/season/weekends). In a second step, we have done an example of a full year optimisation and extrapolated the rest of the results to yearly data. The optimisation was run for three different price level and three different price spread scenarios. This allowed us to assess the sensitivity of the optimisation against price level, price volatility and the level of aggregation.

The results showed that the optimisation outcome is most sensitive to the price volatility followed by the price level and only in third place the aggregation level. The number of households used for the aggregation only made a difference up to 5’000. After, the scaling effects were mostly linear except from 10’000 to 50’000 households. The reason for this is that from 50’000 on, the Aggregator could participate at the ancillary services (ROM) market. A huge importance for the value of DR therefore have the characteristic of the future power price. The higher volatility and level, the more interesting DR becomes. Especially volatility is of high significance. Due to the ongoing electrification and the transition towards renewable energies (reduction in conventional electricity generations), one could expect that power prices will rise again in the long term. A prognosis is very difficult and experts are not sure into what direction the power price will develop. The increase in volatility seems likely though, which is good news for the value of SEMIAH technology.

After extrapolating the data from the representative days to a full year, monetary earned per installation per year, what equals the second overall objective of WP9 according to the DOW. The variation was large and went from nearly zero to a 113 EUR with a mean of 37 EUR and a standard deviation of 31 EUR. 37 EUR per installation per year is not nothing but it is also not a lot. Hence, to assess the profitability of the technology, we had to consider the cost side as well. We estimated the CAPEX and OPEX for a set up as defined in the optimisation. Based on the value added and the costs, we calculated the NPV for the different scenarios and checked if it would be worth to invest or not. Except in a few very optimistic cases it turned not to be worth to invest into the technology. Therefore, examined by what factor we would have to increase the yearly revenue so the DR system starts to become profitable. At 250% of the initial revenue, it started to become interesting to invest. What first seems like an unrealistic goal is not unlikely. When other devices such as heating systems or EVS are integrated into the DR system, much more of the consumption of a household is controlled and can be shifted. Boiler consumption is rather small compared to heating and EV consumption. Not only could with the integration of more devices be more energy shifted to optimise against the price, also would it be much easier to participate at the ancillary service market and therefore benefits form jumps in revenue. Thus, a revenue of 250% of the initial one is possible.

The master thesis of Funk & Wood (2017), which is part of D9.2, mostly assed the possibility of peak-shaving to save the DSO grid investment costs. In their work, they found the same effects with boilers and that it is difficult to earn much on optimising them against the electricity price and ancillary service market. They found however, that boilers are very suitable for the use of peak shaving. Especially for specific individual hours, it does not seem to be a problem to cut boiler consumption entirely.

Also, very good results were found when boiler consumption during certain hours of the day for the whole optimisation period. Hence, peak shaving definitively is a highly interesting concept for DSOs but likely needs to be combined with other DR services so it becomes profitable to offer.

Based on all the findings above, we derived three specific business models for the SEMIAH technology, which corresponds the third overall objective of WP9 described in the DOW. The first model was called balancing the gird and uses flexibility to be traded to provide ancillary service markets, DSO balancing markets and DSO peak shaving. The business model is based on the USEF framework and requires an adjustment of the market as they are now. The consumers would be offered smart energy services or better electricity energy tariffs, depending on who would take over the role of the Aggregator. The second model is called procurement costs minimisation. The Aggregator uses the flexibility in this model to minimise the procurement costs at the wholesale market. The households can then benefit from a profit participation, a fixed participation fee or/and energy services. The business model can be applied as of today or in a market based on USEF. Depending on the revenue model, the service can be provided from an Aggregator or an ESCo. The third business case focuses on the level of self-sufficiency of certain grid subgroups. We defined to variations of the business model. One to increase the self-sufficiency level of individual prosumers and one to maximise the level of self-sufficiency for whole neighbourhoods and communities. The first option simply is provided by an ESCo to help prosumers to become as independent from the gird as possible. The service could also be provided form an Aggregator if the feed-in electricity from the prosumer is optimally allocated within its customers. For both options, the prosumers would pay a fee to the service provider. For the second variation of the self-sufficiency model, the individual's need is not the first priority. The aim of the Aggregator is to make the whole participating independent from the grid if possible. The participants do not all have to be prosumer but there needs to be sufficient, so that the model could work. The community then pays a fee to the Aggregator and only purchases electricity if not avoidable. Within the community houses would then basically trade electricity with each other. The business model would run with a highly sophisticated technology and could most likely be implemented under USEF.

We can sum up that there definitively is a value for DR in Europe and it is more than possible that it will contribute to the introduction of renewables. The energy transition is unlikely to be completed without DR. It still is difficult to evaluate exact numbers for any kind of DR services, since there is a lot of unknows and the technology is still developing fast. There are more and more companies focusing on smart technology in all countries. There are still improvements in technology required so that all the visions can be realised. A lot of work is still ahead for the regulators to smooth the way for a truly smart grid.

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Annex A

Swiss Grid tariff calculation:

Calculation of energy costs

$$Energy\ tariff = AP \times MLR \times EO/EC$$

AP = Area price (kr/MWh)
MLR = Marginal loss rate (%)
EO/EC = Energy Output / Energy Consumption (MWh)
The marginal loss rate is calculated on a weekly basis. It is distributed and posted on the State website by Friday 12:00 pm the week before the new rates become valid.

Calculation of Consumption Costs
Normal consumers pay:

$$Consumption\ costs = k \times consumption\ tariff$$

Flexible consumers pay:

$$Consumption\ costs = k_{Category\ n} \times consumption\ tariff_{Category\ n}$$

Large consumers pay:

$$Consumption\ costs = k \times (consumption\ tariff - individual\ reducation)$$

A large customer is defined as one big plant that consumes more than 15 MW in more than 5000 out of 8760 hours a year.

Calculation of k:

$$k = \frac{F^s}{(P_t + F^s_{tot})}$$

If the formula gives $k < 0.5$, k is set to 0.5.

F^S = A single customer's average consumption in MWh during the peak load hour in the preceding 5 years.
F^s_{tot} = Sum of all customer's average consumption in MWh during the peak load hour in the preceding 5 years.
P_t = Total of available winter capacity per joint

Winter capacity
Water power: The highest amount of power that can be produced in a continuous 6-hour period during the highest consumption peak during winter.
Wind power: 50% of available capacity
Thermal power: 100% of available capacity

Annex B

Detailed optimisation results

						consumption over 1y					**consumption over selected days**			
						GWh				MWh	GWh			
level	spread	scenario	sim	#installations	#groups	boiler	resid	grid_resid	PV	BAT	boiler	resid	grid_resid	PV
low	low	1	1	1'000	5	5.1	19.1	182.4	1.4	0.115	0.252	0.941	8.342	0.070
		1	2	2'000	11	10.2	38.8	333.6	5.4	0.675	0.502	1.909	15.891	0.281
		1	3	5'000	25	25.4	96.9	943.8	18.3	3.163	1.250	4.771	44.410	0.938
		1	4	10'000	44	50.6	194.6	1'758.1	37.2	5.571	2.488	9.575	82.240	1.940
		1	5	20'000	84	101.4	383.8	3'787.5	76.0	11.149	4.987	18.884	178.229	3.926
		1	6	50'000	197	252.6	962.5	10'910.5	177.7	24.449	12.424	47.341	524.478	9.248
		1	7	200'000	701	1'012.0	3'853.1	41'770.6	702.0	98.051	49.773	189.529	1'986.489	35.797
		1	8	500'000	1755	2'531.5	9'623.9	105'213.5	1'724.5	235.163	124.502	473.383	4'997.814	88.042
	mid	2	1	1'000	5	5.1	19.1	182.4	1.4	0.115	0.252	0.941	8.342	0.070
		2	2	2000	11	10.2	38.8	333.6	5.4	0.675	0.502	1.909	15.891	0.281
		2	3	5000	25	25.4	96.9	943.8	18.3	3.163	1.250	4.771	44.410	0.938
		2	4	10000	44	50.6	194.6	1'758.1	37.2	5.571	2.488	9.575	82.240	1.940
		2	5	20000	84	101.4	383.8	3'787.5	76.0	11.149	4.987	18.884	178.229	3.926
		2	6	50000	197	252.6	962.5	10'910.5	177.7	24.449	12.424	47.341	524.478	9.248
		2	7	200000	701	1'012.0	3'853.1	41'770.6	702.0	98.051	49.773	189.529	1'986.489	35.797
		2	8	500000	1755	2'531.5	9'623.9	105'213.5	1'724.5	235.163	124.502	473.383	4'997.814	88.042
	high	3	1	1000	5	5.1	19.1	182.4	1.4	0.115	0.252	0.941	8.342	0.070
		3	2	2000	11	10.2	38.8	333.6	5.4	0.675	0.502	1.909	15.891	0.281
		3	3	5000	25	25.4	96.9	943.8	18.3	3.163	1.250	4.771	44.410	0.938
		3	4	10000	44	50.6	194.6	1'758.1	37.2	5.571	2.488	9.575	82.240	1.940
		3	5	20000	84	101.4	383.8	3'787.5	76.0	11.149	4.987	18.884	178.229	3.926
		3	6	50000	197	252.6	962.5	10'910.5	177.7	24.449	12.424	47.341	524.478	9.248
		3	7	200000	701	1'012.0	3'853.1	41'770.6	702.0	98.051	49.773	189.529	1'986.489	35.797
		3	8	500000	1755	2'531.5	9'623.9	105'213.5	1'724.5	235.163	124.502	473.383	4'997.814	88.042

						consumption over 1y					consumption over selected days			
						GWh				MWh	GWh			
level	spread	scenario	sim	#installations	#groups	boiler	resid	grid_resid	PV	BAT	boiler	resid	grid_resid	PV
mid	low	4	1	1000	5	5.1	19.1	182.4	1.4	0.115	0.252	0.941	8.342	0.070
		4	2	2000	11	10.2	38.8	333.6	5.4	0.675	0.502	1.909	15.891	0.281
		4	3	5000	25	25.4	96.9	943.8	18.3	3.163	1.250	4.771	44.410	0.938
		4	4	10000	44	50.6	194.6	1'758.1	37.2	5.571	2.488	9.575	82.240	1.940
		4	5	20000	84	101.4	383.8	3'787.5	76.0	11.149	4.987	18.884	178.229	3.926
		4	6	50000	197	252.6	962.5	10'910.5	177.7	24.449	12.424	47.341	524.478	9.248
		4	7	200000	701	1'012.0	3'853.1	41'770.6	702.0	98.051	49.773	189.529	1'986.489	35.797
		4	8	500000	1755	2'531.5	9'623.9	105'213.5	1'724.5	235.163	124.502	473.383	4'997.814	88.042
	mid	5	1	1'000	5	5.1	19.1	182.4	1.4	0.115	0.252	0.941	8.342	0.070
		5	2	2'000	11	10.2	38.8	333.6	5.4	0.675	0.502	1.909	15.891	0.281
		5	3	5'000	25	25.4	96.9	943.8	18.3	3.163	1.250	4.771	44.410	0.938
		5	4	10'000	44	50.6	194.6	1'758.1	37.2	5.571	2.488	9.575	82.240	1.940
		5	5	20'000	84	101.4	383.8	3'787.5	76.0	11.149	4.987	18.884	178.229	3.926
		5	6	50'000	197	252.6	962.5	10'910.5	177.7	24.449	12.424	47.341	524.478	9.248
		5	7	200'000	701	1'012.0	3'853.1	41'770.6	702.0	98.051	49.773	189.529	1'986.489	35.797
		5	8	500'000	1755	2'531.5	9'623.9	105'213.5	1'724.5	235.163	124.502	473.383	4'997.814	88.042
	high	6	1	1000	5	5.1	19.1	182.4	1.4	0.115	0.252	0.941	8.342	0.070
		6	2	2000	11	10.2	38.8	333.6	5.4	0.675	0.502	1.909	15.891	0.281
		6	3	5000	25	25.4	96.9	943.8	18.3	3.163	1.250	4.771	44.410	0.938
		6	4	10000	44	50.6	194.6	1'758.1	37.2	5.571	2.488	9.575	82.240	1.940
		6	5	20000	84	101.4	383.8	3'787.5	76.0	11.149	4.987	18.884	178.229	3.926
		6	6	50000	197	252.6	962.5	10'910.5	177.7	24.449	12.424	47.341	524.478	9.248
		6	7	200000	701	1'012.0	3'853.1	41'770.6	702.0	98.051	49.773	189.529	1'986.489	35.797
		6	8	500000	1755	2'531.5	9'623.9	105'213.5	1'724.5	235.163	124.502	473.383	4'997.814	88.042

						consumption over 1y					consumption over selected days			
						GWh				MWh	GWh			
level	spread	scenario	sim	#installations	#groups	boiler	resid	grid_resid	PV	BAT	boiler	resid	grid_resid	PV
high	low	7	1	1000	5	5.1	19.1	182.4	1.4	0.115	0.252	0.941	8.342	0.070
		7	2	2000	11	10.2	38.8	333.6	5.4	0.675	0.502	1.909	15.891	0.281
		7	3	5000	25	25.4	96.9	943.8	18.3	3.163	1.250	4.771	44.410	0.938
		7	4	10000	44	50.6	194.6	1'758.1	37.2	5.571	2.488	9.575	82.240	1.940
		7	5	20000	84	101.4	383.8	3'787.5	76.0	11.149	4.987	18.884	178.229	3.926
		7	6	50000	197	252.6	962.5	10'910.5	177.7	24.449	12.424	47.341	524.478	9.248
		7	7	200000	701	1'012.0	3'853.1	41'770.6	702.0	98.051	49.773	189.529	1'986.489	35.797
		7	8	500000	1755	2'531.5	9'623.9	105'213.5	1'724.5	235.163	124.502	473.383	4'997.814	88.042
	mid	8	1	1000	5	5.1	19.1	182.4	1.4	0.115	0.252	0.941	8.342	0.070
		8	2	2000	11	10.2	38.8	333.6	5.4	0.675	0.502	1.909	15.891	0.281
		8	3	5000	25	25.4	96.9	943.8	18.3	3.163	1.250	4.771	44.410	0.938
		8	4	10000	44	50.6	194.6	1'758.1	37.2	5.571	2.488	9.575	82.240	1.940
		8	5	20000	84	101.4	383.8	3'787.5	76.0	11.149	4.987	18.884	178.229	3.926
		8	6	50000	197	252.6	962.5	10'910.5	177.7	24.449	12.424	47.341	524.478	9.248
		8	7	200000	701	1'012.0	3'853.1	41'770.6	702.0	98.051	49.773	189.529	1'986.489	35.797
		8	8	500000	1755	2'531.5	9'623.9	105'213.5	1'724.5	235.163	124.502	473.383	4'997.814	88.042
	high	9	1	1000	5	5.1	19.1	182.4	1.4	0.115	0.252	0.941	8.342	0.070
		9	2	2000	11	10.2	38.8	333.6	5.4	0.675	0.502	1.909	15.891	0.281
		9	3	5000	25	25.4	96.9	943.8	18.3	3.163	1.250	4.771	44.410	0.938
		9	4	10000	44	50.6	194.6	1'758.1	37.2	5.571	2.488	9.575	82.240	1.940
		9	5	20000	84	101.4	383.8	3'787.5	76.0	11.149	4.987	18.884	178.229	3.926
		9	6	50000	197	252.6	962.5	10'910.5	177.7	24.449	12.424	47.341	524.478	9.248
		9	7	200000	701	1'012.0	3'853.1	41'770.6	702.0	98.051	49.773	189.529	1'986.489	35.797
		9	8	500000	1755	2'531.5	9'623.9	105'213.5	1'724.5	235.163	124.502	473.383	4'997.814	88.042

													PB PRICE	0	100
							BASE	OPTIM	OPTIM	OPTIM	OPTIM	OPTIM	OPTIM	OPTIM	OPTIM
					added value of smart control		**cost over selected days**							**PB over selected days**	
					over selected days	(vs #inst)	EUR	EUR						MWh	
level	spread	scenario	sim	#installations	EUR	EUR/inst	BASE	TOTAL	TRLU	TRLD	PEX	PBlong	PBshort	long	short
low	low	1	1	1'000	16	0.02	135'650	135'634	-	-	135'267	-	367	3.555	3.67
		1	2	2'000	500	0.25	255'428	254'928	-	-	254'666	-	262	2.479	2.621
		1	3	5'000	1'690	0.34	705'566	703'876	-	-	703'636	-	240	1.814	2.403
		1	4	10'000	3'580	0.36	1'320'324	1'316'744	-	-	1'316'561	-	182	1.5	1.823
		1	5	20'000	7'429	0.37	2'827'970	2'820'542	-	-	2'820'384	-	158	0.871	1.578
		1	6	50'000	26'507	0.53	8'148'083	8'121'577	-	- 8'050	8'129'488	-	139	0.832	1.391
		1	7	200'000	108'381	0.54	31'127'842	31'019'461	- 1'027	- 34'725	31'055'073	-	140	0.642	1.4
		1	8	500'000	NaN	Nan	78'322'659	NaN	NaN	NaN	NaN	NaN	NaN	NaN	NaN
	mid	2	1	1'000	393	0.39	138'971	138'578	-	-	138'211	-	367	3.529	3.67
		2	2	2000	1'237	0.62	261'504	260'267	-	-	259'988	-	279	2.39	2.79
		2	3	5000	3'569	0.71	723'474	719'905	-	-	719'658	-	247	1.964	2.47
		2	4	10000	7'253	0.73	1'355'016	1'347'763	-	-	1'347'578	-	185	1.634	1.851
		2	5	20000	14'816	0.74	2'902'687	2'887'871	-	-	2'887'692	-	179	1.208	1.787
		2	6	50000	44'498	0.89	8'356'766	8'312'269	-	- 7'701	8'319'823	-	146	0.873	1.459
		2	7	200000	179'632	0.90	31'927'797	31'748'165	- 905	- 33'792	31'782'696	-	165	0.531	1.654
		2	8	500000	446'212	0.89	80'349'575	79'903'363	- 2'346	- 82'613	79'988'176	-	146	0.424	1.459
	high	3	1	1000	1'147	1.15	145'614	144'467	-	-	144'100	-	367	3.554	3.67
		3	2	2000	2'733	1.37	273'656	270'922	-	-	270'643	-	279	2.427	2.795
		3	3	5000	7'344	1.47	759'290	751'945	-	-	751'701	-	244	2.078	2.443
		3	4	10000	14'599	1.46	1'424'401	1'409'802	-	-	1'409'590	-	212	1.827	2.118
		3	5	20000	29'666	1.48	3'052'120	3'022'454	-	-	3'022'300	-	154	1.333	1.543
		3	6	50000	80'994	1.62	8'774'134	8'693'140	-	- 7'530	8'700'525	-	145	1.13	1.447
		3	7	200000	323'117	1.62	33'527'714	33'204'596	- 279	- 32'802	33'237'531	-	147	0.626	1.469
		3	8	500000	NaN	Nan	84'403'425	NaN	NaN	NaN	NaN	NaN	NaN	NaN	NaN

													PB PRICE	0	100
							BASE	OPTIM	OPTIM	OPTIM	OPTIM	OPTIM	OPTIM	OPTIM	OPTIM
					added value of smart control		**cost over selected days**							**PB over selected days**	
					over selected days	(vs #inst)	EUR	EUR						MWh	
level	spread	scenario	sim	#installations	EUR	EUR/inst	BASE	TOTAL	TRLU	TRLD	PEX	PBlong	PBshort	long	short
mid	low	4	1	1000	398	0.40	271'299	270'902	-	-	270'534	-	368	3.565	3.681
		4	2	2000	1'267	0.63	510'856	509'590	-	-	509'327	-	263	2.359	2.627
		4	3	5000	3'618	0.72	1'411'132	1'407'514	-	-	1'407'266	-	249	1.775	2.487
		4	4	10000	7'343	0.73	2'640'648	2'633'305	-	-	2'633'122	-	183	1.486	1.827
		4	5	20000	15'014	0.75	5'655'939	5'640'926	-	-	5'640'776	-	150	0.983	1.501
		4	6	50000	44'935	0.90	16'296'165	16'251'229	-	- 7'723	16'258'808	-	145	0.768	1.445
		4	7	200000	181'325	0.91	62'255'674	62'074'350	- 852	- 33'890	62'108'946	-	146	0.448	1.457
		4	8	500000	NaN	Nan	156'645'295	NaN	NaN	NaN	NaN	NaN	NaN	NaN	NaN
	mid	5	1	1'000	1'154	1.15	277'942	276'789	-	-	276'425	-	364	3.597	3.637
		5	2	2'000	2'752	1.38	523'008	520'255	-	-	519'975	-	280	2.392	2.804
		5	3	5'000	7'384	1.48	1'446'948	1'439'564	-	-	1'439'318	-	246	1.944	2.464
		5	4	10'000	14'684	1.47	2'710'032	2'695'349	-	-	2'695'151	-	198	1.611	1.977
		5	5	20'000	29'818	1.49	5'805'373	5'775'555	-	-	5'775'388	-	167	1.217	1.667
		5	6	50'000	81'357	1.63	16'713'533	16'632'176	-	- 7'534	16'639'551	-	159	0.833	1.593
		5	7	200'000	323'759	1.62	63'855'593	63'531'834	- 277	- 32'832	63'564'782	-	161	0.66	1.611
		5	8	500'000	808'155	1.62	160'699'150	159'890'996	- 1'045	- 80'373	159'972'278	-	136	0.579	1.361
	high	6	1	1000	2'660	2.66	291'227	288'567	-	-	288'200	-	367	3.554	3.67
		6	2	2000	5'746	2.87	547'311	541'565	-	-	541'285	-	279	2.427	2.795
		6	3	5000	14'933	2.99	1'518'579	1'503'646	-	-	1'503'402	-	244	2.078	2.443
		6	4	10000	29'409	2.94	2'848'801	2'819'392	-	-	2'819'180	-	212	1.827	2.118
		6	5	20000	59'486	2.97	6'104'239	6'044'753	-	-	6'044'599	-	154	1.333	1.543
		6	6	50000	154'414	3.09	17'548'265	17'393'851	-	- 7'246	17'400'950	-	146	1.203	1.462
		6	7	200000	613'400	3.07	67'055'414	66'442'014	- 57	- 31'968	66'473'910	-	129	0.675	1.293
		6	8	500000	NaN	Nan	168'806'818	NaN	NaN	NaN	NaN	NaN	NaN	NaN	NaN

													PB PRICE	0	100
							BASE	OPTIM	OPTIM	OPTIM	OPTIM	OPTIM	OPTIM	OPTIM	OPTIM
					added value of smart control		cost over selected days							PB over selected days	
					over selected days	(vs #inst)	EUR	EUR						MWh	
level	spread	scenario	sim	#installations	EUR	EUR/inst	BASE	TOTAL	TRLU	TRLD	PEX	PBlong	PBshort	long	short
high	low	7	1	1000	1'163	1.16	542'599	541'435	-	-	541'068	-	367	3.579	3.67
		7	2	2000	2'793	1.40	1'021'713	1'018'920	-	-	1'018'657	-	263	2.414	2.63
		7	3	5000	7'482	1.50	2'822'265	2'814'783	-	-	2'814'534	-	249	1.827	2.49
		7	4	10000	14'870	1.49	5'281'297	5'266'426	-	-	5'266'244	-	182	1.468	1.825
		7	5	20000	30'184	1.51	11'311'881	11'281'697	-	-	11'281'546	-	150	0.933	1.504
		7	6	50000	82'235	1.64	32'592'334	32'510'099	-	- 7'571	32'517'532	-	138	0.675	1.375
		7	7	200000	328'032	1.64	124'511'367	124'183'335	- 267	- 32'961	124'216'422	-	141	0.437	1.408
		7	8	500000	NaN	Nan	313'290'637	NaN	NaN	NaN	NaN	NaN	NaN	NaN	NaN
	mid	8	1	1000	2'671	2.67	555'884	553'213	-	-	552'846	-	367	3.579	3.67
		8	2	2000	5'785	2.89	1'046'016	1'040'231	-	-	1'039'950	-	280	2.393	2.804
		8	3	5000	15'017	3.00	2'893'896	2'878'879	-	-	2'878'633	-	246	1.886	2.459
		8	4	10000	29'565	2.96	5'420'065	5'390'500	-	-	5'390'308	-	192	1.688	1.915
		8	5	20000	59'801	2.99	11'610'747	11'550'946	-	-	11'550'781	-	165	1.315	1.654
		8	6	50000	155'168	3.10	33'427'066	33'271'898	-	- 7'270	33'279'025	-	143	0.829	1.432
		8	7	200000	616'393	3.08	127'711'187	127'094'794	- 56	- 32'002	127'126'688	-	163	0.545	1.633
		8	8	500000	1'535'770	3.07	321'398'300	319'862'530	- 144	- 78'172	319'940'707	-	139	0.498	1.388
	high	9	1	1000	5'687	5.69	582'455	576'767	-	-	576'400	-	367	3.554	3.67
		9	2	2000	11'772	5.89	1'094'623	1'082'851	-	-	1'082'571	-	279	2.427	2.795
		9	3	5000	30'111	6.02	3'037'159	3'007'049	-	-	3'006'804	-	244	2.078	2.443
		9	4	10000	59'030	5.90	5'697'603	5'638'574	-	-	5'638'362	-	212	1.827	2.118
		9	5	20000	119'127	5.96	12'208'483	12'089'356	-	-	12'089'202	-	154	1.333	1.543
		9	6	50000	301'709	6.03	35'096'542	34'794'833	-	- 7'222	34'801'907	-	148	1.156	1.475
		9	7	200000	1'194'834	5.97	134'110'878	132'916'044	- 48	- 31'565	132'947'526	-	131	0.62	1.309
		9	8	500000	NaN	Nan	337'613'760	NaN	NaN	NaN	NaN	NaN	NaN	NaN	NaN

Annex C

Cost for the implementation of SEMIAH technology

Scenario	Efficiency Factor	Share of PV installations	Share of installations with PV and battery	CAPEX	CAPEX per installation (average)	Number of technicans	Number of computer technicans	Costs ressources	Licence costs	OPEX	OPEX per installation
1000	1	0.104	0.013	236940	236.94	1	1	118000	31000	149000	149
2000	1	0.1945	0.0445	463890	231.945	1	1	118000	32000	150000	75
5000	1	0.2648	0.08	1145840	229.168	1	2	186000	35000	221000	44.2
10000	0.95	0.2688	0.0694	2167076	216.7076	2	2	236000	40000	276000	27.6
20000	0.95	0.2707	0.06825	4328603	216.43015	4	3	404000	50000	454000	22.7
50000	0.9	0.25314	0.06094	10304483	206.08966	10	3	704000	80000	784000	15.68
200000	0.85	0.246985	0.06109	39092929.5	195.464648	40	5	2340000	230000	2570000	12.85
500000	0.8	0.24329	0.058926	92187860	184.37572	100	8	5544000	530000	6074000	12.148

Annex D

NPV Revenue Factor 1 Scenario

					Revenue Factor =	1.00	Interest rate =	Income in Year						
level	spread	sim	CAPEX	OPEX Yearly	Yearly Revenue	Yearly Profit		0	1	2	3	4	5	NPV
low	low	1	-236'940.00	-149'000.00	148.74	-148'851.26	-	-236'940	-148'851.26	-148'851.26	-148'851.26	-148'851.26	-148'851.26	-878271.72
		2	-463'890.00	-150'000.00	4'699.30	-145'300.70	-	-463'890	-145'300.70	-145'300.70	-145'300.70	-145'300.70	-145'300.70	-1082058.23
		3	-1'145'840.00	-221'000.00	15'873.30	-205'126.70	-	-1'145'840	-205'126.70	-205'126.70	-205'126.70	-205'126.70	-205'126.70	-2001930.24
		4	-2'167'076.00	-276'000.00	33'620.87	-242'379.13	-	-2'167'076	-242'379.13	-242'379.13	-242'379.13	-242'379.13	-242'379.13	-3151140.53
		5	-4'328'603.00	-454'000.00	69'754.83	-384'245.17	-	-4'328'603	-384'245.17	-384'245.17	-384'245.17	-384'245.17	-384'245.17	-5858444.49
		6	-10'304'483.00	-784'000.00	248'900.33	-535'099.67	-	-10'304'483	-535'099.67	-535'099.67	-535'099.67	-535'099.67	-535'099.67	-12290324.66
		7	-39'092'929.50	-2'570'000.00	1'017'711.95	-1'552'288.05	-	-39'092'930	-1'552'288.05	-1'552'288.05	-1'552'288.05	-1'552'288.05	-1'552'288.05	-44542600.36
		8	-92'187'860.00	-6'074'000.00	NaN	NaN	-	-92'187'860	NaN	NaN	NaN	NaN	NaN	-89070396.14
	mid	1	-236'940.00	-149'000.00	7'260.52	-141'739.48	-	-236'940	-141'739.48	-141'739.48	-141'739.48	-141'739.48	-141'739.48	-847247.51
		2	-463'890.00	-150'000.00	22'858.49	-127'141.51	-	-463'890	-127'141.51	-127'141.51	-127'141.51	-127'141.51	-127'141.51	-1002841.13
		3	-1'145'840.00	-221'000.00	65'924.52	-155'075.48	-	-1'145'840	-155'075.48	-155'075.48	-155'075.48	-155'075.48	-155'075.48	-1783588.31
		4	-2'167'076.00	-276'000.00	133'974.84	-142'025.16	-	-2'167'076	-142'025.16	-142'025.16	-142'025.16	-142'025.16	-142'025.16	-2713359.48
		5	-4'328'603.00	-454'000.00	273'683.09	-180'316.91	-	-4'328'603	-180'316.91	-180'316.91	-180'316.91	-180'316.91	-180'316.91	-4968834.10
		6	-10'304'483.00	-784'000.00	821'976.94	37'976.94	1.00	-10'304'483	37'976.94	37'976.94	37'976.94	37'976.94	37'976.94	-9790352.76
		7	-39'092'929.50	-2'570'000.00	3'318'205.23	748'205.23	1.00	-39'092'930	748'205.23	748'205.23	748'205.23	748'205.23	748'205.23	-34506998.73
		8	-92'187'860.00	-6'074'000.00	8'242'538.16	2'168'538.16	1.00	-92'187'860	2'168'538.16	2'168'538.16	2'168'538.16	2'168'538.16	2'168'538.16	-79610431.51
	high	1	-236'940.00	-149'000.00	21'514.40	-127'485.60	-	-236'940	-127'485.60	-127'485.60	-127'485.60	-127'485.60	-127'485.60	-785066.82
		2	-463'890.00	-150'000.00	51'290.77	-98'709.23	-	-463'890	-98'709.23	-98'709.23	-98'709.23	-98'709.23	-98'709.23	-878809.04
		3	-1'145'840.00	-221'000.00	137'810.90	-83'189.10	-	-1'145'840	-83'189.10	-83'189.10	-83'189.10	-83'189.10	-83'189.10	-1469993.38
		4	-2'167'076.00	-276'000.00	273'926.47	-2'073.53	-	-2'167'076	-2'073.53	-2'073.53	-2'073.53	-2'073.53	-2'073.53	-2102838.73
		5	-4'328'603.00	-454'000.00	556'653.81	102'653.81	1.00	-4'328'603	102'653.81	102'653.81	102'653.81	102'653.81	102'653.81	-3734411.27
		6	-10'304'483.00	-784'000.00	1'519'774.57	735'774.57	1.00	-10'304'483	735'774.57	735'774.57	735'774.57	735'774.57	735'774.57	-6746301.73
		7	-39'092'929.50	-2'570'000.00	6'062'964.25	3'492'964.25	1.00	-39'092'930	3'492'964.25	3'492'964.25	3'492'964.25	3'492'964.25	3'492'964.25	-22533345.87
		8	-92'187'860.00	-6'074'000.00	NaN	NaN	-	-92'187'860	NaN	NaN	NaN	NaN	NaN	-89070396.14

level	spread	sim	CAPEX	OPEX Yearly	Yearly Revenue	Yearly Profit		0	1	2	3	4	5	NPV
					Revenue Factor =	1.00	Interest rate =	Income in Year						
mid	low	1	-236'940.00	-149'000.00	7'360.82	-141'639.18	-	-236'940	-141'639.18	-141'639.18	-141'639.18	-141'639.18	-141'639.18	-846809.97
		2	-463'890.00	-150'000.00	23'452.45	-126'547.55	-	-463'890	-126'547.55	-126'547.55	-126'547.55	-126'547.55	-126'547.55	-1000250.05
		3	-1'145'840.00	-221'000.00	66'995.42	-154'004.58	-	-1'145'840	-154'004.58	-154'004.58	-154'004.58	-154'004.58	-154'004.58	-1778916.65
		4	-2'167'076.00	-276'000.00	135'965.20	-140'034.80	-	-2'167'076	-140'034.80	-140'034.80	-140'034.80	-140'034.80	-140'034.80	-2704676.77
		5	-4'328'603.00	-454'000.00	277'994.73	-176'005.27	-	-4'328'603	-176'005.27	-176'005.27	-176'005.27	-176'005.27	-176'005.27	-4950025.12
		6	-10'304'483.00	-784'000.00	832'016.51	48'016.51	1.00	-10'304'483	48'016.51	48'016.51	48'016.51	48'016.51	48'016.51	-9746556.45
		7	-39'092'929.50	-2'570'000.00	3'357'392.69	787'392.69	1.00	-39'092'930	787'392.69	787'392.69	787'392.69	787'392.69	787'392.69	-34336048.57
		8	-92'187'860.00	-6'074'000.00	NaN	NaN	-	-92'187'860	NaN	NaN	NaN	NaN	NaN	-89070396.14
	mid	1	-236'940.00	-149'000.00	21'622.50	-127'377.50	-	-236'940	-127'377.50	-127'377.50	-127'377.50	-127'377.50	-127'377.50	-784595.25
		2	-463'890.00	-150'000.00	51'593.93	-98'406.07	-	-463'890	-98'406.07	-98'406.07	-98'406.07	-98'406.07	-98'406.07	-877486.52
		3	-1'145'840.00	-221'000.00	138'411.78	-82'588.22	-	-1'145'840	-82'588.22	-82'588.22	-82'588.22	-82'588.22	-82'588.22	-1467372.12
		4	-2'167'076.00	-276'000.00	275'244.12	-755.88	-	-2'167'076	-755.88	-755.88	-755.88	-755.88	-755.88	-2097090.65
		5	-4'328'603.00	-454'000.00	558'936.90	104'936.90	1.00	-4'328'603	104'936.90	104'936.90	104'936.90	104'936.90	104'936.90	-3724451.59
		6	-10'304'483.00	-784'000.00	1'525'012.89	741'012.89	1.00	-10'304'483	741'012.89	741'012.89	741'012.89	741'012.89	741'012.89	-6723450.24
		7	-39'092'929.50	-2'570'000.00	6'068'799.10	3'498'799.10	1.00	-39'092'930	3'498'799.10	3'498'799.10	3'498'799.10	3'498'799.10	3'498'799.10	-22507892.08
		8	-92'187'860.00	-6'074'000.00	15'148'693.66	9'074'693.66	1.00	-92'187'860	9'074'693.66	9'074'693.66	9'074'693.66	9'074'693.66	9'074'693.66	-49483229.80
	high	1	-236'940.00	-149'000.00	50'130.64	-98'869.36	-	-236'940	-98'869.36	-98'869.36	-98'869.36	-98'869.36	-98'869.36	-660232.21
		2	-463'890.00	-150'000.00	108'290.56	-41'709.44	-	-463'890	-41'709.44	-41'709.44	-41'709.44	-41'709.44	-41'709.44	-630154.90
		3	-1'145'840.00	-221'000.00	281'414.79	60'414.79	1.00	-1'145'840	60'414.79	60'414.79	60'414.79	60'414.79	60'414.79	-843540.16
		4	-2'167'076.00	-276'000.00	554'209.70	278'209.70	1.00	-2'167'076	278'209.70	278'209.70	278'209.70	278'209.70	278'209.70	-880139.74
		5	-4'328'603.00	-454'000.00	1'121'020.66	667'020.66	1.00	-4'328'603	667'020.66	667'020.66	667'020.66	667'020.66	667'020.66	-1272434.59
		6	-10'304'483.00	-784'000.00	2'909'929.91	2'125'929.91	1.00	-10'304'483	2'125'929.91	2'125'929.91	2'125'929.91	2'125'929.91	2'125'929.91	-681930.52
		7	-39'092'929.50	-2'570'000.00	11'559'505.28	8'989'505.28	1.00	-39'092'930	8'989'505.28	8'989'505.28	8'989'505.28	8'989'505.28	8'989'505.28	1444596.79
		8	-92'187'860.00	-6'074'000.00	NaN	NaN	-	-92'187'860	NaN	NaN	NaN	NaN	NaN	-89070396.14
high	low	1	-236'940.00	-149'000.00	21'841.29	-127'158.71	-	-236'940	-127'158.71	-127'158.71	-127'158.71	-127'158.71	-127'158.71	-783640.81
		2	-463'890.00	-150'000.00	52'431.34	-97'568.66	-	-463'890	-97'568.66	-97'568.66	-97'568.66	-97'568.66	-97'568.66	-873833.46
		3	-1'145'840.00	-221'000.00	140'453.72	-80'546.28	-	-1'145'840	-80'546.28	-80'546.28	-80'546.28	-80'546.28	-80'546.28	-1458464.41
		4	-2'167'076.00	-276'000.00	279'156.34	3'156.34	1.00	-2'167'076	3'156.34	3'156.34	3'156.34	3'156.34	3'156.34	-2080024.11
		5	-4'328'603.00	-454'000.00	566'631.74	112'631.74	1.00	-4'328'603	112'631.74	112'631.74	112'631.74	112'631.74	112'631.74	-3690883.88
		6	-10'304'483.00	-784'000.00	1'543'760.78	759'760.78	1.00	-10'304'483	759'760.78	759'760.78	759'760.78	759'760.78	759'760.78	-6641665.00
		7	-39'092'929.50	-2'570'000.00	6'158'000.85	3'588'000.85	1.00	-39'092'930	3'588'000.85	3'588'000.85	3'588'000.85	3'588'000.85	3'588'000.85	-22118761.10
		8	-92'187'860.00	-6'074'000.00	NaN	NaN	-	-92'187'860	NaN	NaN	NaN	NaN	NaN	-89070396.14
	mid	1	-236'940.00	-149'000.00	50'346.59	-98'653.41	-	-236'940	-98'653.41	-98'653.41	-98'653.41	-98'653.41	-98'653.41	-659290.16
		2	-463'890.00	-150'000.00	109'032.14	-40'967.86	-	-463'890	-40'967.86	-40'967.86	-40'967.86	-40'967.86	-40'967.86	-626919.86
		3	-1'145'840.00	-221'000.00	283'024.29	62'024.29	1.00	-1'145'840	62'024.29	62'024.29	62'024.29	62'024.29	62'024.29	-836518.90
		4	-2'167'076.00	-276'000.00	557'210.57	281'210.57	1.00	-2'167'076	281'210.57	281'210.57	281'210.57	281'210.57	281'210.57	-867048.85
		5	-4'328'603.00	-454'000.00	1'127'048.87	673'048.87	1.00	-4'328'603	673'048.87	673'048.87	673'048.87	673'048.87	673'048.87	-1246137.30
		6	-10'304'483.00	-784'000.00	2'924'423.79	2'140'423.79	1.00	-10'304'483	2'140'423.79	2'140'423.79	2'140'423.79	2'140'423.79	2'140'423.79	-618702.88
		7	-39'092'929.50	-2'570'000.00	11'617'037.83	9'047'037.83	1.00	-39'092'930	9'047'037.83	9'047'037.83	9'047'037.83	9'047'037.83	9'047'037.83	1695575.03
		8	-92'187'860.00	-6'074'000.00	28'944'357.04	22'870'357.04	1.00	-92'187'860	22'870'357.04	22'870'357.04	22'870'357.04	22'870'357.04	22'870'357.04	10698550.62
	high	1	-236'940.00	-149'000.00	107'363.13	-41'636.87	-	-236'940	-41'636.87	-41'636.87	-41'636.87	-41'636.87	-41'636.87	-410562.95
		2	-463'890.00	-150'000.00	222'231.43	72'231.43	1.00	-463'890	72'231.43	72'231.43	72'231.43	72'231.43	72'231.43	-133102.73
		3	-1'145'840.00	-221'000.00	568'415.81	347'415.81	1.00	-1'145'840	347'415.81	347'415.81	347'415.81	347'415.81	347'415.81	408464.31
		4	-2'167'076.00	-276'000.00	1'114'337.82	838'337.82	1.00	-2'167'076	838'337.82	838'337.82	838'337.82	838'337.82	838'337.82	1563346.05
		5	-4'328'603.00	-454'000.00	2'248'837.10	1'794'837.10	1.00	-4'328'603	1'794'837.10	1'794'837.10	1'794'837.10	1'794'837.10	1'794'837.10	3647517.42
		6	-10'304'483.00	-784'000.00	5'695'547.29	4'911'547.29	1.00	-10'304'483	4'911'547.29	4'911'547.29	4'911'547.29	4'911'547.29	4'911'547.29	11469961.58
		7	-39'092'929.50	-2'570'000.00	22'555'589.44	19'985'589.44	1.00	-39'092'930	19'985'589.44	19'985'589.44	19'985'589.44	19'985'589.44	19'985'589.44	49413578.34
		8	-92'187'860.00	-6'074'000.00	NaN	NaN	-	-92'187'860	NaN	NaN	NaN	NaN	NaN	-89070396.14

NPV Revenue Factor 2.5 Scenario

					Revenue Factor =	2.50	Interest rate =	Income in Year						
level	spread	sim	CAPEX	OPEX Yearly	Yearly Revenue	Yearly Profit		0	1	2	3	4	5	NPV
low	low	1	-236'940.00	-149'000.00	148.74	-148'628.15	-	-236'940	-148'628.15	-148'628.15	-148'628.15	-148'628.15	-148'628.15	-877298.44
		2	-463'890.00	-150'000.00	4'699.30	-138'251.75	-	-463'890	-138'251.75	-138'251.75	-138'251.75	-138'251.75	-138'251.75	-1051308.09
		3	-1'145'840.00	-221'000.00	15'873.30	-181'316.75	-	-1'145'840	-181'316.75	-181'316.75	-181'316.75	-181'316.75	-181'316.75	-1898062.44
		4	-2'167'076.00	-276'000.00	33'620.87	-191'947.81	-	-2'167'076	-191'947.81	-191'947.81	-191'947.81	-191'947.81	-191'947.81	-2931140.52
		5	-4'328'603.00	-454'000.00	69'754.83	-279'612.91	-	-4'328'603	-279'612.91	-279'612.91	-279'612.91	-279'612.91	-279'612.91	-5401999.95
		6	-10'304'483.00	-784'000.00	248'900.33	-161'749.17	-	-10'304'483	-161'749.17	-161'749.17	-161'749.17	-161'749.17	-161'749.17	-10661631.85
		7	-39'092'929.50	-2'570'000.00	1'017'711.95	-25'720.14	-	-39'092'930	-25'720.14	-25'720.14	-25'720.14	-25'720.14	-25'720.14	-37883147.11
		8	-92'187'860.00	-6'074'000.00	NaN	NaN	-	-92'187'860	NaN	NaN	NaN	NaN	NaN	-89070396.14
	mid	1	-236'940.00	-149'000.00	7'260.52	-130'848.70	-	-236'940	-130'848.70	-130'848.70	-130'848.70	-130'848.70	-130'848.70	-799737.91
		2	-463'890.00	-150'000.00	22'858.49	-92'853.77	-	-463'890	-92'853.77	-92'853.77	-92'853.77	-92'853.77	-92'853.77	-853265.34
		3	-1'145'840.00	-221'000.00	65'924.52	-56'188.69	-	-1'145'840	-56'188.69	-56'188.69	-56'188.69	-56'188.69	-56'188.69	-1352207.61
		4	-2'167'076.00	-276'000.00	133'974.84	58'937.09	-	-2'167'076	58'937.09	58'937.09	58'937.09	58'937.09	58'937.09	-1836687.88
		5	-4'328'603.00	-454'000.00	273'683.09	230'207.72	-	-4'328'603	230'207.72	230'207.72	230'207.72	230'207.72	230'207.72	-3177973.98
		6	-10'304'483.00	-784'000.00	821'976.94	1'270'942.36	1.00	-10'304'483	1'270'942.36	1'270'942.36	1'270'942.36	1'270'942.36	1'270'942.36	-4411702.10
		7	-39'092'929.50	-2'570'000.00	3'318'205.23	5'725'513.08	1.00	-39'092'930	5'725'513.08	5'725'513.08	5'725'513.08	5'725'513.08	5'725'513.08	-12794143.05
		8	-92'187'860.00	-6'074'000.00	8'242'538.16	14'532'345.41	1.00	-92'187'860	14'532'345.41	14'532'345.41	14'532'345.41	14'532'345.41	14'532'345.41	-25674936.55
	high	1	-236'940.00	-149'000.00	21'514.40	-95'214.00	-	-236'940	-95'214.00	-95'214.00	-95'214.00	-95'214.00	-95'214.00	-644286.18
		2	-463'890.00	-150'000.00	51'290.77	-21'773.08	-	-463'890	-21'773.08	-21'773.08	-21'773.08	-21'773.08	-21'773.08	-543185.13
		3	-1'145'840.00	-221'000.00	137'810.90	123'527.25	-	-1'145'840	123'527.25	123'527.25	123'527.25	123'527.25	123'527.25	-568220.30
		4	-2'167'076.00	-276'000.00	273'926.47	408'816.18	-	-2'167'076	408'816.18	408'816.18	408'816.18	408'816.18	408'816.18	-310386.03
		5	-4'328'603.00	-454'000.00	556'653.81	937'634.53	1.00	-4'328'603	937'634.53	937'634.53	937'634.53	937'634.53	937'634.53	-91916.91
		6	-10'304'483.00	-784'000.00	1'519'774.57	3'015'436.42	1.00	-10'304'483	3'015'436.42	3'015'436.42	3'015'436.42	3'015'436.42	3'015'436.42	3198425.46
		7	-39'092'929.50	-2'570'000.00	6'062'964.25	12'587'410.62	1.00	-39'092'930	12'587'410.62	12'587'410.62	12'587'410.62	12'587'410.62	12'587'410.62	17139989.11
		8	-92'187'860.00	-6'074'000.00	NaN	NaN	-	-92'187'860	NaN	NaN	NaN	NaN	NaN	-89070396.14

					Revenue Factor =	2.50	Interest rate =	Income in Year						
level	spread	sim	CAPEX	OPEX Yearly	Yearly Revenue	Yearly Profit		0	1	2	3	4	5	NPV
mid	low	1	-236'940.00	-149'000.00	7'360.82	-130'597.95	-	-236'940	-130'597.95	-130'597.95	-130'597.95	-130'597.95	-130'597.95	-798644.04
		2	-463'890.00	-150'000.00	23'452.45	-91'368.87	-	-463'890	-91'368.87	-91'368.87	-91'368.87	-91'368.87	-91'368.87	-846787.65
		3	-1'145'840.00	-221'000.00	66'995.42	-53'511.44	-	-1'145'840	-53'511.44	-53'511.44	-53'511.44	-53'511.44	-53'511.44	-1340528.47
		4	-2'167'076.00	-276'000.00	135'965.20	63'913.00	-	-2'167'076	63'913.00	63'913.00	63'913.00	63'913.00	63'913.00	-1814981.12
		5	-4'328'603.00	-454'000.00	277'994.73	240'986.83	-	-4'328'603	240'986.83	240'986.83	240'986.83	240'986.83	240'986.83	-3130951.52
		6	-10'304'483.00	-784'000.00	832'016.51	1'296'041.29	1.00	-10'304'483	1'296'041.29	1'296'041.29	1'296'041.29	1'296'041.29	1'296'041.29	-4302211.31
		7	-39'092'929.50	-2'570'000.00	3'357'392.69	5'823'481.72	1.00	-39'092'930	5'823'481.72	5'823'481.72	5'823'481.72	5'823'481.72	5'823'481.72	-12366767.65
		8	-92'187'860.00	-6'074'000.00	NaN	NaN	-	-92'187'860	NaN	NaN	NaN	NaN	NaN	-89070396.14
	mid	1	-236'940.00	-149'000.00	21'622.50	-94'943.75	-	-236'940	-94'943.75	-94'943.75	-94'943.75	-94'943.75	-94'943.75	-643107.25
		2	-463'890.00	-150'000.00	51'593.93	-21'015.17	-	-463'890	-21'015.17	-21'015.17	-21'015.17	-21'015.17	-21'015.17	-539878.82
		3	-1'145'840.00	-221'000.00	138'411.78	125'029.45	-	-1'145'840	125'029.45	125'029.45	125'029.45	125'029.45	125'029.45	-561667.14
		4	-2'167'076.00	-276'000.00	275'244.12	412'110.31	-	-2'167'076	412'110.31	412'110.31	412'110.31	412'110.31	412'110.31	-296015.82
		5	-4'328'603.00	-454'000.00	558'936.90	943'342.25	1.00	-4'328'603	943'342.25	943'342.25	943'342.25	943'342.25	943'342.25	-67017.70
		6	-10'304'483.00	-784'000.00	1'525'012.89	3'028'532.22	1.00	-10'304'483	3'028'532.22	3'028'532.22	3'028'532.22	3'028'532.22	3'028'532.22	3255554.20
		7	-39'092'929.50	-2'570'000.00	6'068'799.10	12'601'997.75	1.00	-39'092'930	12'601'997.75	12'601'997.75	12'601'997.75	12'601'997.75	12'601'997.75	17203623.57
		8	-92'187'860.00	-6'074'000.00	15'148'693.66	31'797'734.15	1.00	-92'187'860	31'797'734.15	31'797'734.15	31'797'734.15	31'797'734.15	31'797'734.15	49643067.72
	high	1	-236'940.00	-149'000.00	50'130.64	-23'673.40	-	-236'940	-23'673.40	-23'673.40	-23'673.40	-23'673.40	-23'673.40	-332199.65
		2	-463'890.00	-150'000.00	108'290.56	120'726.39	-	-463'890	120'726.39	120'726.39	120'726.39	120'726.39	120'726.39	78450.23
		3	-1'145'840.00	-221'000.00	281'414.79	482'536.97	1.00	-1'145'840	482'536.97	482'536.97	482'536.97	482'536.97	482'536.97	997912.76
		4	-2'167'076.00	-276'000.00	554'209.70	1'109'524.25	1.00	-2'167'076	1'109'524.25	1'109'524.25	1'109'524.25	1'109'524.25	1'109'524.25	2746361.46
		5	-4'328'603.00	-454'000.00	1'121'020.66	2'348'551.64	1.00	-4'328'603	2'348'551.64	2'348'551.64	2'348'551.64	2'348'551.64	2'348'551.64	6063024.81
		6	-10'304'483.00	-784'000.00	2'909'929.91	6'490'824.79	1.00	-10'304'483	6'490'824.79	6'490'824.79	6'490'824.79	6'490'824.79	6'490'824.79	18359353.50
		7	-39'092'929.50	-2'570'000.00	11'559'505.28	26'328'763.21	1.00	-39'092'930	26'328'763.21	26'328'763.21	26'328'763.21	26'328'763.21	26'328'763.21	77084845.76
		8	-92'187'860.00	-6'074'000.00	NaN	NaN	-	-92'187'860	NaN	NaN	NaN	NaN	NaN	-89070396.14
high	low	1	-236'940.00	-149'000.00	21'841.29	-94'396.77	-	-236'940	-94'396.77	-94'396.77	-94'396.77	-94'396.77	-94'396.77	-640721.14
		2	-463'890.00	-150'000.00	52'431.34	-18'921.66	-	-463'890	-18'921.66	-18'921.66	-18'921.66	-18'921.66	-18'921.66	-530746.17
		3	-1'145'840.00	-221'000.00	140'453.72	130'134.31	-	-1'145'840	130'134.31	130'134.31	130'134.31	130'134.31	130'134.31	-539397.87
		4	-2'167'076.00	-276'000.00	279'156.34	421'890.86	1.00	-2'167'076	421'890.86	421'890.86	421'890.86	421'890.86	421'890.86	-253349.46
		5	-4'328'603.00	-454'000.00	566'631.74	962'579.34	1.00	-4'328'603	962'579.34	962'579.34	962'579.34	962'579.34	962'579.34	16901.58
		6	-10'304'483.00	-784'000.00	1'543'760.78	3'075'401.95	1.00	-10'304'483	3'075'401.95	3'075'401.95	3'075'401.95	3'075'401.95	3'075'401.95	3460017.29
		7	-39'092'929.50	-2'570'000.00	6'158'000.85	12'825'002.12	1.00	-39'092'930	12'825'002.12	12'825'002.12	12'825'002.12	12'825'002.12	12'825'002.12	18176451.02
		8	-92'187'860.00	-6'074'000.00	NaN	NaN	-	-92'187'860	NaN	NaN	NaN	NaN	NaN	-89070396.14
	mid	1	-236'940.00	-149'000.00	50'346.59	-23'133.53	-	-236'940	-23'133.53	-23'133.53	-23'133.53	-23'133.53	-23'133.53	-329844.52
		2	-463'890.00	-150'000.00	109'032.14	122'580.34	-	-463'890	122'580.34	122'580.34	122'580.34	122'580.34	122'580.34	86537.83
		3	-1'145'840.00	-221'000.00	283'024.29	486'560.73	1.00	-1'145'840	486'560.73	486'560.73	486'560.73	486'560.73	486'560.73	1015465.89
		4	-2'167'076.00	-276'000.00	557'210.57	1'117'026.42	1.00	-2'167'076	1'117'026.42	1'117'026.42	1'117'026.42	1'117'026.42	1'117'026.42	2779088.69
		5	-4'328'603.00	-454'000.00	1'127'048.87	2'363'622.17	1.00	-4'328'603	2'363'622.17	2'363'622.17	2'363'622.17	2'363'622.17	2'363'622.17	6128768.03
		6	-10'304'483.00	-784'000.00	2'924'423.79	6'527'059.48	1.00	-10'304'483	6'527'059.48	6'527'059.48	6'527'059.48	6'527'059.48	6'527'059.48	18517422.61
		7	-39'092'929.50	-2'570'000.00	11'617'037.83	26'472'594.58	1.00	-39'092'930	26'472'594.58	26'472'594.58	26'472'594.58	26'472'594.58	26'472'594.58	77712291.34
		8	-92'187'860.00	-6'074'000.00	28'944'357.04	66'286'892.61	1.00	-92'187'860	66'286'892.61	66'286'892.61	66'286'892.61	66'286'892.61	66'286'892.61	200097518.76
	high	1	-236'940.00	-149'000.00	107'363.13	119'407.82	-	-236'940	119'407.82	119'407.82	119'407.82	119'407.82	119'407.82	291973.51
		2	-463'890.00	-150'000.00	222'231.43	405'578.57	1.00	-463'890	405'578.57	405'578.57	405'578.57	405'578.57	405'578.57	1321080.65
		3	-1'145'840.00	-221'000.00	568'415.81	1'200'039.51	1.00	-1'145'840	1'200'039.51	1'200'039.51	1'200'039.51	1'200'039.51	1'200'039.51	4127923.92
		4	-2'167'076.00	-276'000.00	1'114'337.82	2'509'844.55	1.00	-2'167'076	2'509'844.55	2'509'844.55	2'509'844.55	2'509'844.55	2'509'844.55	8855075.94
		5	-4'328'603.00	-454'000.00	2'248'837.10	5'168'092.76	1.00	-4'328'603	5'168'092.76	5'168'092.76	5'168'092.76	5'168'092.76	5'168'092.76	18362904.82
		6	-10'304'483.00	-784'000.00	5'695'547.29	13'454'868.21	1.00	-10'304'483	13'454'868.21	13'454'868.21	13'454'868.21	13'454'868.21	13'454'868.21	48739083.76
		7	-39'092'929.50	-2'570'000.00	22'555'589.44	53'818'973.60	1.00	-39'092'930	53'818'973.60	53'818'973.60	53'818'973.60	53'818'973.60	53'818'973.60	197007299.62
		8	-92'187'860.00	-6'074'000.00	NaN	NaN	-	-92'187'860	NaN	NaN	NaN	NaN	NaN	-89070396.14